PROPRIETARY

UNITED STATES GOVERNMENT
MEMORANDUM

To: File

Through: Supervisor, Operations Review and Approval
Supervisor, Operations Unit

From: Geologist

Subject: Log Analysis in Support of Reserve Estimate

I have completed log analysis of the first three Kuvlum wells. The results of the last two Kuvlum wells, Y-0865 #1 and Y-0866 #2, indicated that ARCO Alaska, Inc. (ARCO), has substantially overestimated the extent and productivity of the field. This is indicated by the drastic decrease in reservoir quality reported in the second well, Y-0865 #1, and by the lack of reservoir in Y-0865 #2 where presumably it has been removed by erosion. However, in drilling Y-0865 #1, ARCO discovered a second reservoir overlying the first. This result strongly supported the interpretation of Kuvlum reservoir presented by Chevron U.S.A. during the creation of the Kuvlum Unit. While this second reservoir is not as thick as the first encountered in the Kuvlum #1 well, Y-0866 #1, it could also add to the reserve estimate of the Kuvlum Unit. Since the log analysis indicates that the Kuvlum sands vary laterally, additional drilling is necessary to accurately define the reservoir and estimate reserves. If ARCO is asked to provide an estimate of the size of the Kuvlum accumulation, they should be advised to include in their estimate the size and geographic extent of the new reservoir and also predict where both reservoirs will be removed by erosion. This could result in either or both expansion and contraction of the Kuvlum Unit.

bcc: File OCS Y-0866 Well No. 1, 5A

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PROPRIETARY

MEMO

TO:
ENGINEER'S FILE, 5A, OCS Y-0866 WELL NO. 1

THRU:
SUPERVISOR, OPERATIONS UNIT
SUPERVISOR, ORA

FROM: GEOLOGIST

SUBJECT:
LOG ANALYSIS IN SUPPORT OF RESERVE ESTIMATE

I have completed log analysis of the first three Kuvlum wells. The results of the last two Kuvlum wells, Y-0865#1 and Y-0866#2 indicate that Arco has substantially overestimated the extent and productivity of the field. This is indicated by the drastic decrease in reservoir quality reported in the second well, Y-0865#1, and by the lack of reservoir in Y-0865#2 where presumably it has been removed by erosion. However, in drilling Y-0865#1 Arco discovered a second reservoir overlying the first. This result strongly supported the interpretation of Kuvlum reservoir presented by Chevron during the creation of the Kuvlum Unit. While this second reservoir is not as thick as the first encountered in the Kuvlum #1 well, Y-0866#1, it could also add to the reserve estimate of Kuvlum Unit. Since the log analysis indicates that the Kuvlum sands vary laterally, additional drilling is necessary to accurately define the reservoir and estimate reserves. If Arco is asked to provide an estimate of the size of the Kuvlum accumulation, they should be advised to include in their estimate the size and geographic extent of the new reservoir and also predict where both reservoirs will be removed be erosion. This could result in either or both expansion and contraction of the Kuvlum Unit.

Details forthcoming? If not, what is this?

OPRIETARY

MEMO

August 5, 1994

TO: KUVLUM UNIT FILE

THROUGH: REGIONAL SUPERVISOR, FIELD OPERATIONS
SUPERVISOR, ORA
SUPERVISOR, OPERATIONS UNIT

FROM: GEOLOGIST

SUBJECT: PETROPHYSICAL ANALYSIS OF KUVLUM PROSPECT, Y-0866 No.1

This memo will present a preliminary petrophysical analysis of the Kuvlum Prospect. The discovery well, OCS-Y 0866 No.1 (Kuvlum No.1), was drilled by ARCO during the 1992 open water drilling season. The well was logged and tested productive over a 155 foot interval.(see attachment No.1) Subsequently, during the 1993 open-water drilling season, two additional wells, OCS-Y 0865 No.1 (Kuvlum No.2) and OCS-Y 0866 No.2 (Kuvlum No.3) tested the limits of the field. Discouraging results from those wells were reported by ARCO. Currently, no additional drilling is planned for Kuvlum Prospect.

Stratigraphy:

The Kuvlum reservoir consists of Oligo-Miocene shelfal sands and underlying channel sands of the advancing delta front. These sediments were deposited into the Kaktovik sedimentary basin and resemble the sands encountered in the Hammerhead No.1 well which occurs along depositional strike to the northwest. The reservoir sands overly the silts and coal-rich muds of the advancing delta front. The top of the reservoir is sealed by a well consolidated, dark grey, silty, micaceous mudstone with local pyrite and sparse coal. To the northeast in the Kuvlum No.3 well, erosion was observed to have removed the entire interval of Kuvlum reservoir sands. While to the southwest in well Kuvlum No.2 the shelfal sands grade to silts and muds.

Lithology:

The sandstones of the Kuvlum reservoir are described as moderately consolidated, structureless to mottled to crudely laminated with internal grading, light grey, moderate- to well-sorted, subangular, very fine-grained, cherty, quartz sand to silty sand. Where the sandstones occur with mudstones they are described as well- to poorly sorted and contain wood/coal fragments some of which are pyritized.

The sandstones were encountered between 6507' and 6662' for a total thickness of 155'. Sidewall cores collected within this interval were described as consisting of sands and mud. From the results of the coring no internal subdivisions of the reservoir were evident.

Logging Tools:

The suite of logs utilized for the petrophysical analysis included: the Array Induction Log in place of the standard resistivity suite; the Dipole Sonic Log; and the Lithodensity/Neutron Log. The Array Induction Tool is a recent addition which permits the identification of zones of deep invasion and directly reads both R_{XO} and R_T. Additionally, a Formation Microimager log was obtained to permit an estimation of the sand count.

Log Editing:

The gamma ray traces of each logging tool were compared and no depth adjustment was performed. The neutron logs were compensated with the procedure of Elphick (Elphick,1987). Gamma ray traces were compensated for mud weight and hole volume.

Shale Analysis:

The gamma ray index of the formation was calculated assuming a maximum response, in shales, of 88.7 API units and a minimum response, in sands, of 30.0 API units. The clay volume was calculated from the gamma ray index using the Clavier formula.

$$V_{CL} = (1.7-(3.38-(GR+0.7))^2)^{1/2}$$

where V_{CL} = volume of clay
and GR = gamma ray index

Porosity:

Total and effective porosities were determined from the density-neutron crossplot. (see attachment No. 2) Total porosities were calculated as the numerical average (except in the presence of gas) of the density and neutron log readings.

The total porosity was calculated as the numerical average of the uncorrected log readings.

where $\Phi_{Density}$ = the density log response
and $\Phi_{Neutron}$ = the neutron log response
then Φ_{Total} = the total porosity

$$\Phi_{Total} = (\Phi_{Density} + \Phi_{Neutron}) / 2$$

Effective porosities were determined by first removing the effects of shale and then averaging the shale-corrected porosities. The density log had a response of 13.5% porosity in shale; while the neutron log (corrected) had a response of 35.8% in shale. Both log readings were corrected for shale using the clay volume.

where Φ_{Shale} is the porosity observed in shales
and V_{CL} is the shale volume
and $\Phi_{Uncorrected}$ is the uncorrected porosity
then $\Phi_{Shale\ Corrected}$ is the shale corrected porosity

$$\Phi_{Shale\ Corrected} = \Phi_{Uncorrected} - (V_{CL} * \Phi_{Shale})$$

The effective porosity was taken as the numerical average of the shale corrected density and shale corrected neutron log readings.

where $\Phi_{DensitySC}$ = the density log response corrected for shales
and $\Phi_{NeutronSC}$ = the neutron log response corrected for shales
then $\Phi_{Effective}$ = the effective porosity

$$\Phi_{Effective} = (\Phi_{DensitySC} + \Phi_{NeutronSC}) / 2$$

Where the presence of gas was inferred from $\Phi_{Density} > \Phi_{Neutron}$ (the crossover effect), Φ_{Total} and $\Phi_{Effective}$ were calculated from a the root mean square formula.

$$\Phi_{Total} = ((\Phi_{Density}{}^2 + \Phi_{Neutron}{}^2)/2)^{1/2}$$

$$\Phi_{Effective} = ((\Phi_{DensitySC}{}^2 + \Phi_{NeutronSC}{}^2)/2\ )^{1/2}$$

Formation Water Resistivity:

The formation water resistivity was determined by analysis of well Y-0866#1 which penetrated the formation beneath the oil/water contact. The resistivity of the formation water at the formation temperature was 0.153 ohms. This value was determined from the chemical analysis of formation water in Kuvlum #2 and agrees well with the value of 0.155 ohms derived from the spontaneous potential log using the modified method of Bates & Konen (1977)(see Asquith).

Dispersed Clay Analysis:

Oil saturations within the formation were determined by both a dual water and a dispersed clay analyses. Dispersed clay within the sandstones was reported by the sidewall core analysis. However, the high water resistivity, in excess of 0.1 ohms, indicated that these values be treated with caution and compared with results obtained via the dual water method. The amount of dispersed clay within the formation was calculated from the "Q" factor (the ration of dispersed to total clay). The equation chosen to calculate Q did not require the sonic log.

$$Q = (\Phi_{Total} - \Phi_{Effective})/\Phi_{Total}$$

The volume of dispersed clay (V_{Disp}) may then be determined.

$$V_{Disp} = Q * V_{Clay}$$

and the volume of shale (V_{Sh}) is taken as the remainder of the clay.

$$V_{Sh} = (1-Q) * V_{Clay}$$

Water Saturations with Dispersed Clay Method:

When Q is known, the water saturation of the reservoir is calculated from the dispersed clay equation.

$$S_{we}= ((((0.8/\Phi^2)*(R_W/R_T))+(Q/2)^2)^{1/2})/(1-Q)$$

Water Saturations with Dual Water Analysis:

A Dual Water Analysis may be necessary when dispersed clay is associated with high formation water resistivities (> 0.10 ohm-m). In the current petrophysical analysis a dual water analysis was also performed. The total porosity of the adjacent shale was first calculated.

$$\Phi_{TSH} = \delta\Phi_{DSH} + (1-\delta)\Phi_{NSH} = 0.202\ (20.2\%)$$

Where Φ_{TSH} is the total porosity of the adjacent shale,
Φ_{DSH} is the density log porosity of that shale,
Φ_{NSH} is the neutron log porosity of that shale,
and δ is a proportional constant generally equal to 0.7.

The total porosity of the formation is then calculated from the effective porosity and the volume of shale.

$$\Phi_T = \Phi_e + (V_{SH} * \Phi_{TSH})$$

where Φ_T is the total porosity of the formation,
Φ_e is the effective porosity of the formation,
V_{SH} is the volume of shale,
and Φ_{TSH} is the total porosity of shale previously calculated.

Next, the clay-bound water saturation (S_b) is derived.

$$S_b = V_{CL} * (\Phi_{TSH}/\Phi_T)$$

The value of the bound water resistivity (R_b) is subsequently determined for the formation.

$$R_b = R_{SH} * \Phi_{TSH}^2 = 3.92*(0.202)^2 = 0.160 \text{ ohm-m.}$$

where R_{SH} is the resistivity of the dispersed shale phase determined from a crossplot of V_{CL} vs R_T.(see attachment No.3)

The apparent water resistivity in the shaly sand (R_{WA}) is found from the equation:

$$R_{WA} = R_T*\Phi_T^2$$

The total water saturation corrected for clay is then

$$S_{WT} = b + (b^2+(R_W/R_{WA}))^{1/2}$$

where $b = (S_b(1-(R_W/R_b))$.

The effective water saturation of the shaly sand (S_{we}) may now be determined from the equation:

$$S_{WE} = (S_{WT} - S_b)/(1-S_b)$$

PERMEABLE SANDS (sand count):

The agreement between the dispersed clay and dual water methods suggests that the dispersed clay model is valid for the Kuvlum reservoir. Producible sands may be determined for dispersed clay reservoirs from a crossplot of Q versus $\Phi_{Effective}$. From such a crossplot producible sands were distinguished. The actual equation used:

IF $2*\Phi_{Effective} - Q > 0.1$ THEN the sands are producible;
IF $2*\Phi_{Effective} - Q > 0.0$ THEN the sands are producible with stimulation;
IF $2*\Phi_{Effective} - Q < 0.0$ THEN the sands are non-producible.

This equation is only valid for sands with the field and represents an extrapolation from the crossplot of Dresser. (1979)

The calculated value of producible sands was 96.5 feet of producible sands in the interval between 6,507 to 6,662 ft. TVD. This value is also in close agreement with the 96 feet (corrected to 93 feet) obtained from the formation microscanner. This also appears to confirm the validity of the dispersed clay model.

Pay Determination:

Pay intervals within the formation were identified by the following criteria:

(1) Effective porosity (Φ) greater than 10%
(2) Water saturation (S_{we}) less than 50%
(3) $2*\Phi_{Effective} - Q > 0.1$

These criteria served to define three major potential zones of production. Additionally, two intervals appear capable of production only under stimulation. The intervals are numbered from the bottom to the top:

Zone 1 (6662-6608) 54 feet Major Zone of Production
Zone 2 (6608-6557) 51 feet producible under stimulation
Zone 3 (6557-6530) 27 feet Major Zone of Production
Zone 4 (6530-6519) 11 feet producible under stimulation
Zone 5 (6519-6507) 12 feet Major Zone of Production

Zone 1 is the largest producing interval within the well and additionally contains the highest porosity and lowest shale contents. The interval appears subdivided into two subintervals from 6662-6624 and 6624-6607 which may well act as distinct flow units. Minor producible intervals occur in Zone 2 which, however may not be laterally continuous in the vicinity of the well. The second and third major producible intervals, Zones 3 and 5, are probably continuous in the vicinity of the well due to their increased thickness. Zone 4 which separates these reservoirs may be non-productive due to reduced permeability and serve as a barrier to vertical fluid flow. Hence, the value of the gas/oil contact at 6518 feet TVD should only be considered an upper limit and gas may occur to 6530 feet TVD in other locations.

The calculated values for the total field as well as the respective zones are presented in Table 1.

Zone	Gross Ft.	Net Pay	$\Phi_{Effective}$	Swe	fluid
1	54.0 feet	51.5 feet	22.5%	34.9%	oil
2	51.0 feet	11.5 feet	18.2%	46.2%	oil
3	27.0 feet	23.5 feet	18.9%	43.6%	oil
4	11.0 feet	00.5 feet	17.3%	45.1%	oil ?
5	12.0 feet	09.5 feet	18.6%	39.9%	gas