CORE ANALYSIS FOR OPTIMUM RESERVOIR EXPLOITATION

W. M. HENSEL, JR.
Sun Oil Company

INTRODUCTION

Core data can play a vital role in development drilling programs and recovery planning operations. Well-conceived field coring programs and subsequent laboratory testing procedures can strengthen log interpretation criteria, aid in completion/stimulation operations, provide a sound basis for reserves estimates and reservoir modeling, and supply much-needed guidance in secondary and tertiary recovery programs.

This paper presents the need for pre-planning during the development phase of the reservoir so that necessary parameters are properly evaluated. Coring methods, coring fluids, preservation techniques, and basic laboratory testing procedures are discussed. Suggestions are given for selecting samples for special analysis test work.

THE FIELD CORING PROGRAM

The special core study actually begins during the development drilling program of the field. Failure on the part of all concerned to recognize this can severely encumber the proper planning of pressure maintenance, secondary and tertiary recovery programs. After all of the wells have been drilled it is too late to recognize the need for representative cores. A handful of sophisticated suites of logs is poor consolation to the reservoir engineer charged with designing the most efficient means for the recovery of millions of barrels of oil.

The development drilling program gets a lot of attention in its early stages. Drilling problems are encountered and ways are sought to lower the per footage costs. Coring can only increase such costs. Logs provide a quick, clean way to identify producing intervals. Cores, although helpful, have a longer turn-around time and may cause delays in assigning perforations. The impetus for coring must come from those responsible for the long-range look at the reservoir. A logical choice is the reservoir engineering staff. Through their guidance an orderly plan for coring operations may be followed, thus ensuring that proper data will be available for future studies.

So how may effective plans be made for the coring program to maximize the return on the data dollar invested? Some companies reportedly use rules-of-thumb based on the estimated oil-in-place. Certainly the worth of the reservoir should be a part of the consideration, but it is also important to look ahead and plan the coring to provide guidance in certain areas. What are these areas and how can cores and core data contribute?

1. Log Interpretation
   a. Information derived from cores sets critical grain density values unobtainable by other means. Many sandstone formations do not have a grain density of 2.65 gm/cc and carbonates can vary over a wide range. a wide range.
   b. Water saturation data from cores taken with oil-base muds are used to confirm log-derived water values.
   c. Core porosities help provide a base line for logs.
   d. Formation Factor and Resistivity Index values obtained from cores can mean better log interpretations.
   e. Permeability relationships can be measured on cores and these, in turn, used to calculate permeability from logs. This can be a significant refinement over empirically-calculated permeability values.

2. Completion/Stimulation Operations
   a. Drilling and completion fluids can be

better designed by having representative core material on which to perform tests.

b. Proper acid formulas can be specified through a knowledge of the mineralogy obtained from cores.

c. Fracturing techniques can be designed around testing programs performed on cores.

d. Gas/oil and water/oil contacts can be picked from core analyses.

e. Thin sands interbedded with shales are difficult, if not impossible, to pinpoint by logs. Cores are the firsthand evidence needed for these difficult completions.

3. Estimation of Primary Reserves

   a. Net pay criteria (porosity, permeability cutoffs) can be established from core data.

   b. Core/log relationships can be established on a few wells and noncored wells evaluated, with added confidence, using logs only.

   c. Unit displacement efficiencies of gas cap and bottom water drives can be evaluated.

   d. Net-to-gross sand ratios can be established by cores on interbedded formations. Logs tend to yield "average" data which can be misleading.

4. Secondary and Tertiary Recovery Planning

   a. Gas drive and waterflood residual oil values can be obtained through core analyses.

   b. Formation wettability can be estimated and this, in turn, used as guidance in planning recovery techniques.

   c. Fireflood planning can be improved by having core material to use in test programs.

   d. Water quality and treating requirements during waterflood operations can be investigated with representative water samples and core material.

   e. The choice of chemicals used in polymer and similar floods can be influenced by flow tests conducted on representative cores.

   f. Diagnostic wells can be cored behind the flood fronts and the data obtained used to evaluate the project.

   g. Recovery techniques such as wettability alterations, surfactant or emulsion flooding must be planned through laboratory core testing programs.

In order to provide the necessary guidance in these areas, there is the need to: (1) core early in the drilling program, (2) core a cross-section of wells, (3) core across fluid contacts if practical, (4) core at least one well with an oil-base fluid, and (5) core at least one well in which wettability preservation is considered.

By coring early in the drilling program, core material will be available for tests designed to assist in drilling and completion operations. Also, core/log relationships can be established and these guidelines used for the remainder of the well evaluations.

There is a need for coring a cross-section of wells in order to define the lithology and to know with confidence what is truly representative of the formation. This is extremely important in later core study planning and reservoir modeling.

Cores are firsthand evidence as to the presence and location of gas/oil and/or water/oil contacts. Transition zones can be defined which can guide perforation and stimulation operations. The decision as to the location of field development wells can be affected by fluid contact information and pressure maintenance and secondary recovery operations are likewise influenced.

The primary purpose of coring with an oil-base fluid is to provide water saturation information. Since no water contacts the formation, the water saturations obtained by this coring method may be considered as minimal values. If mobile waters are not present at the time of coring, the water saturations may be used as true in-place values. These water saturations may be compared with log-derived values, values from cores taken with water-base fluids and restored state values obtained through core testing procedures.

Wettability considerations may be overlooked during the hustle and bustle of the field development program. One key well, properly engineered to provide formation wettability information, can pay handsome dividends in future reservoir operations.[1]

CORING METHODS

Several innovations in coring have come about in recent years. Conventional core barrels are no longer limited to 50-ft cores. It is now possible to select the length of core barrel in multiples of 30 feet, and it is common to cut and recover as much as 90 feet of full diameter core in one trip. The obvious advantage is the saving of several round trips when coring hundreds of continuous feet of formation.

There are several commercially available means for recovering cores from unconsolidated or extremely soft and friable formations. Some of these devices provide a three-inch diameter core encased in reinforced rubber tubing.[2] Others recover the core material in heavy-wall plastic sleeves. Generally speaking, shorter cores are attempted with these devices; twenty feet is usually the maximum possible core length. There are other advantages of these coring techniques such as providing a core suitably preserved for transporting to the lab. On tight-hole type wells cores recovered in such a fashion prevent unauthorized persons from viewing them. Most of the devices encapsulate the core on a foot-by-foot basis so that the last foot cut does not have the weight of the full column of cores bearing down on it. This, of course, is of great value in that unconsolidated cores are not compacted and upon arrival at the surface have a much better chance of representing the in situ formation condition. This ability to recover suitable core material from these types of formations has prompted new techniques of core analysis. These will be discussed later.

Vertically fractured formations also present problems in coring. Conventional barrels that require the core to be fed up into the inner barrel are frequently jammed by the wedging action of vertically fractured cores. These formations also lend themselves to the rubber tube technique and full recoveries are commonplace.

The most difficult task to accomplish is that of recovering cores in such a manner that the fluid saturations are unaltered from those existing at bottomhole conditions. The filtrates of various coring fluids more often than not invade the pore spaces and change the fluid content. This is thought to occur immediately at the bit face, and the degree of flushing is a function of several variables which will be discussed under CORING FLUIDS. Subsequent changes take place as the core is brought to the surface as it undergoes a reduction in pressure. Dissolved gases come out of solution and may expel fluids from the pore spaces until relative permeability relationships are satisfied. The end results can be a set of fluid saturations completely unlike the bottomhole saturations. The pressure core barrel[3] can eliminate the gas expansion/pressure reduction phase. This device incorporates a means of sealing off the core after the last foot has been cut. The core barrel is brought to the surface and the whole assembly is frozen using dry ice. The core may then be removed from the barrel and suitably preserved for transportation to the lab. Obviously special testing techniques are required.

CORING FLUIDS

The literature contains many articles on the subject of the invasion and flushing of the core pore spaces by the filtrates of the various coring fluids.[4,5,6,7,8] Reference is made to the effect on air permeability values by the swelling of formation clays due to the cores being invaded by a fresh water drilling fluid filtrate.[8] Oil-base fluids likewise are documented as having invaded cores.[7] In either case the invasion occurs when the pressure at the bottom of the column of drilling fluid exceeds the reservoir pressure. The degree of flushing appears to be controlled by several variables.[5] These may include:

1. The filtrate loss properties of the drilling fluid
2. The viscosities of the associated fluids
3. The diameter of the core
4. The horizontal permeability of the core
5. The rate of bit penetration
6. The vertical permeability of the formation
7. The formation pressure
8. The pressure at the bottom of the column of drilling fluid
9. The type of porosity development
10. The chemical composition of the drilling fluid.

Complete flushing of the pore spaces by the filtrates may not be of serious consequence providing certain saturation conditions exist in situ. For instance, if the formation contains minimum or irreducible water saturation, the pore spaces containing oil may be flushed completely by an oil filtrate and the recovered cores will contain the same water saturation existing in the reservoir. Likewise, if a formation contains minimum or residual oil saturation and has been pressure depleted, the pore spaces containing water may be completely flushed by a water filtrate and the recovered cores will contain the same oil saturation existing in the reservoir.

Compressibility and/or temperature corrections could be required in either case.

Intermediate saturation conditions of either oil or water make the selection of the proper drilling fluid a difficult one. In an attempt to solve this problem, special coring fluids have been designed.[5] These fluids are tailored to provide low invasion into the cores and borehole wall by rapidly building up an impermeable filter cake consisting of suspended solid matter in the drilling fluid. The suspended solids may be as simple as calcium carbonate (limestone) ground to a particle size determined by the formation pore size distribution. Dynamic core flow studies conducted under simulated reservoir conditions can yield data to assist in planning the drilling fluid formula.

Saturations may not be a major consideration in coring a particular well. Preserving the integrity of the chemical and physical properties of the rock may be the prime objective. Water-base fluids can have effects on certain minerals. Water-sensitive clays need to be protected from swelling and/or dispersion. The fluid system that satisfies core mineral protection requirements may also provide protection to the formation affording a better, less involved well completion. Sodium chloride, calcium chloride or potassium chloride mud systems may efficiently stabilize formation clays. One of the newer mud systems involves the use of DAP (Diammonium Phosphate) as an additive.[9]

Under certain conditions lease crude may satisfy formation-core protection requirements while at the same time providing other useful data from the cores. The main advantage is that foreign fluids would not contaminate the cores or formation. Formation pressures could preclude a pure lease crude system. Certain crudes might not lend themselves to use as a coring fluid. Also, there might be the element of danger associated with the use of lease crude due to the potential explosion and fire hazards present.

ON-LOCATION CORE HANDLING AND PRESERVATION PROCEDURES

It has previously been pointed out that fluids within the porous network of cores are subjected to changing conditions due to the coring processes and subsequent pressure changes upon bringing the cores to the surface. After the cores have been removed from the conventional core barrel further changes may occur due to evaporation of fluids, further pressure reduction and chemical or physical changes due to exposure to the elements.[10] Under ordinary circumstances it is impractical to completely control these latter changes; however, certain precautions and procedures, if followed, will minimize them and therefore allow for better and more meaningful analyses of the cores.

Cores should be handled as quickly and efficiently as possible to reduce the amount of time they are exposed to atmospheric conditions. Even under the most ideal of conditions the fluids in the cores may evaporate fairly rapidly. Obviously, hot and windy days afford the maximum chance for evaporation. On the other hand, rain and/or high humidity conditions might contribute to fluid changes by affording an opportunity for the cores to take on water. Only under certain conditions should cores be washed down with a hose or the like. If the cores are to be preserved for saturation analysis, excess drilling mud may be removed by wiping with waste material.

After the cores have been layed out, measured and described, the preservation process should begin immediately. Normally, cores are preserved in one-foot increments. The most common short-term preservation method consists of placing the cores in heavy-duty plastic bags. The ends of the bags are sealed and the cores placed in cardboard boxes for transporting to the laboratory. Proper identification of the footage is extremely important as the data may be useless if the depth interval is not known.

Other preservation methods may include (1) long plastic, metal or waxed fiberboard tubes in which several feet of core may be inserted, (2) tinned cans, sealed at the wellsite, (3) wax or plastic coating of the cores after first wrapping in Saran Wrap and aluminum foil, and (4) freezing with dry ice.[10] The choice of preservation method may vary due to several factors such as transportation time, type of analysis required, etc.

In summary, the attention and care the cores receive during the handling and preservation stages will affect the quality of the data determined from them. This in turn may greatly influence costly operations such as completions, reserves estimates, log correlations, and recovery methods.

BASIC LABORATORY TESTS

Too often the basic core testing phase is regarded lightly. This phase starts the data pool and can also provide the suite of prepared samples for future special analysis work. "Quickie" methods may satisfy the immediate urgency for some numbers, but later correlation attempts or history matches may suffer.

First, consider sampling. Normally, conventional plug-type analyses are conducted at a density of one sample per foot. Few, if any, formations are so homogeneous that sampling is not a problem. There are at least two schools of thought as to sampling technique. One school suggests sampling each foot at some predetermined location such as the exact midpoint of each foot. The theory is that on a statistical basis this sampling will prevent both high grading and low grading and will yield an overall proper average suite of samples. An argument against this method suggests that over a section of formation the total number of samples and their frequency are not sufficient to provide rigorous representation. Another school suggests that each foot be examined and a "representative" sample taken. If, for example, the foot is generally shale-streaked, the sample should contain a similar percentage of shale laminations. Sometimes a representative sample may not be possible due to a drastic change in lithology within a foot. In these cases it would be appropriate to subdivide the foot and then sample each increment on a representative basis.

"Whole Core" testing procedures eliminate, to a great extent, the problem of representative sampling. This type of analysis lends itself particularly well to carbonate formations that are fractured or whose porosity developments are associated with vugs or solution cavities.[11] Even though the complete cored section is tested, care should be taken in subdividing the interval for the whole core tests.

Conventional summation-of-fluids plug-type analyses actually employ three samples.[10] The first is a 100 to 200-gram crushed sample that is subjected to high temperature retorting to drive off the contained oil and water. The second is a small (20-30 gram) sample taken adjacent to the saturation sample location. This sample is used to measure the unoccupied or gas-filled pores by mercury injection. Mathematically the data measured on these two samples are combined for porosity and saturation values. The third sample is a small plug (usually one-inch in diameter) that is used for the permeability determination. A discussion of this third sample is in order. Most field laboratories employ "quickie" methods to prepare this sample for permeability determination. When the oil contained in the pore spaces is of a sufficiently high gravity, the plugs are merely heated to free them of oil and water. In some cases excessive temperatures are used to speed things up, and erroneous permeability values can result from the shrinkage of clays.[12] If low-gravity oils are present, extraction using solvents can also be a hit-or-miss operation. If proper extraction and drying procedures are used, the plugs will yield better permeability values. Also, a direct Boyle's Law type of porosity can be measured on these samples which, in many cases, will yield better porosity-permeability relationships than are afforded using the summation-of-fluids porosity values because the porosity and permeability are measured on the same increment of formation. This type of plug preparation also yields a suite of samples that are ready for use in detailed reservoir engineering studies.

Unconsolidated or extremely friable formations require special treatment. Normally, formations such as these are cored using the rubber sleeve or plastic sleeve barrels. The plugs are taken by either of two techniques. In the first a hollow, metal punch is used to withdraw a sample through a "window" cut in the sleeve material. The second procedure consists of drilling a core plug using liquid nitrogen as the bit coolant.[13] In either case the plug is inserted into a pre-formed thin-wall metal jacket, fine-mesh screens are affixed at the ends, and the excess metal is folded over the edges of the screens to hold them in place. The jacket is then seated to the plug by hydraulic means. Plugs so prepared are usually tested for fluid saturations using Dean-Stark procedures. Pore volume and/or grain volume may be determined by Boyle's Law or resaturation methods. Care should be exercised that proper overburden pressure requirements are met to ensure meaningful values.[14,15] Once again, these plugs, properly prepared, constitute a suite of samples that may be used in special core analysis work dealing with relative permeability, capillary pressure, etc.

SELECTION OF SAMPLES FOR SPECIAL CORE ANALYSIS

Preliminary discussions of special core analysis studies generally include ideas regarding the sample selection and number required. Unfortunately, there are occasions when the cost of the study weighs heavily in deciding on the latter. Special core tests are expensive, but the overall purpose of the study and its consequences must be kept in perspective. Sufficient funds should be allotted to permit a reasonable effort toward representing the complete range of rock properties.

Consider the objective of the special core study. For example, the problem may involve the assignment of reserves particularly as relating to water saturation in a sandstone reservoir having a known oil/water contact. Full capillary pressure curve tests are in order. Hopefully, a sufficient number of wells were cored and analyzed so as to know with confidence the general rock properties. A good start is to make a simple semi-log plot of the basic porosity and permeability data. These plots typically show a great deal of point scatter but usually a trend is evident. A "best fit" line may be drawn or a least squares relationship calculated. One approach is to bracket the general grouping with two parallel lines after which the "average" line is more easily visualized. Normally, capillary pressure relationships can be correlated with permeability in sandstones, so a suite of plugs representing the permeability range of the reservoir in question is desired. It may be desirable to establish a lower limit or "cut-off" value for either porosity or permeability. This could affect the range of permeability over which the study is to be conducted, or the capillary pressure study itself may yield data to help establish the cut-offs. Once the permeability range has been determined, samples lying closest to the average line should be selected. The advantage of having properly prepared basic analysis plugs is now obvious. The plugs having the exact properties desired are ready and accessible for the special tests; otherwise, new plugs must be drilled, prepared, and evaluated for porosity and permeability in hopes that a suite of plugs can be found that conform to the established relationships.

The capillary pressure curves are determined and if everything goes well, it is reasonable to expect the curves to array themselves from right to left in order of increasing permeability. Since interpolation between curves is permissible, water saturations may be assigned to any given foot or vertical section throughout the complete reservoir.

Had the reservoir in question been composed of carbonate-type rocks, samples might have been chosen to represent a range of porosity values rather than permeability. It is not a hard and fast rule but carbonates, particularly vuggy, heterogeneous ones, are more apt to show reasonable capillary-pressure/porosity correlations.[16]

Selection of samples for other types of special core tests should be made in similar manners. In all cases the complete range of rock properties should be studied and some statistical considerations be given to the number and distribution of samples. A sufficient number of samples should be tested so that the nonconforming sample can be identified, and its data given the appropriate weight in the engineering study. Determining a reservoir's rock characteristics is not a simple, one-shot matter. Statistics are a vital part of the overall consideration and should be used in a constructive fashion.

CONCLUSIONS

The role of the data obtainable through representative core material should be recognized by everyone concerned with the reservoir. Engineers, geologists, and log analysts need to request coring programs in order to provide much-needed guidance in their respective fields of responsibility. Managers should seriously consider these requests by allotting neccessary funds. The long-range picture must be kept in mind.

The need for coring must be recognized early in the drilling program. A cross-section of wells needs to be cored. Water saturations should be confirmed by coring with oil-type fluids, and wettability-oriented coring procedures should be planned.

Long-term core preservation methods should be employed on selected samples in order that suitable material will be available for special studies later in the life of the reservoir.

Care should be exercised during the basic core testing phase. "Quickie" methods of core plug preparation should be avoided. Boyle's Law porosity values should be determined on the permeability plugs to provide for more meaningful porosity-permeability relationships. All plugs should be properly stored for future use in special core analysis programs.

Special preparation techniques are required for unconsolidated or extremely friable sandstone formations. Hydraulic loading conditions are needed for the determination of proper porosity and permeability values.

Special core analysis studies should be planned so that an adequate number of samples are tested.

The suite of samples should be selected from porosity-permeability correlations. The samples should cover the full range of known physical properties of the reservoir rock. Where possible, the core plugs prepared during the basic core testing should be used.

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