JCPT

West Delta Block 84—Methodology and Analysis of a Previously Orphaned Field

W.C. KIMBRELL
Kimbrell and Associates, LLC & Louisiana State University
A.K. WOJTANOWICZ
Louisiana State University

Abstract

This paper describes the effort to justify, document, and confirm proven, unproven, undeveloped, and bypassed remaining oil and gas reserves in West Delta Block 84 Field; at one time an orphaned field off the coast of Louisiana. The methodology used for the evaluation provides an insight into how to quickly and efficiently identify worthwhile and economic marginal properties, even with incomplete or missing information. This methodology is being used as a part of the development of an expert system for the evaluation of marginal and/or orphaned wells, reservoirs, and fields.

West Delta Block 84 is located off the coast of Plaquemines Parish, Louisiana, near the mouth of the Mississippi River in about 20 ft of water. Conoco discovered it in 1955 with the drilling of the SL 2551 No. 1 well to a total depth of 14,500 ft. It has produced over 9.8 MMSTB of oil and 21 BCF of gas. It was shut in for a period of almost ten years while languishing in and out of bankruptcy court from 1990 to 2000, and was actually orphaned by the state at one point during this time.

Available data was organized and pieced together for the field, but was still lacking in completeness. As in most cases when dealing with older marginal fields, an ability to deal with missing and incomplete information was necessary to complete the analysis.

Introduction

There are reportedly 343,030 inactive, shut-in, and/or orphaned wells nationwide, of which 34,355 are in Louisiana. In many cases, these wells are idle and orphaned, not because their resources have been depleted, but because of other factors. These factors might include low product price, high cost of operations, unrelated financial problems, or the inability or lack of resources to properly describe the reservoir and identify the potential for additional recovery, among other things. It is simply not known, with any accuracy to an outside party looking in, exactly why a well is shut in or orphaned.

Historically, small and large independent producers have entered into fields previously operated and owned by the major oil companies. These underfinanced and understaffed independents find themselves working off cash flow and unable to find the financial resources to work over the idle wells, much less do the research that many of the wells and reservoirs deserve and need. The wells may have potential, but no one has the time or the money to pursue these presumably marginal targets.

There is an incentive to identify potential in these shut-in/orphaned wells since their plugging would be terminal and, in the case of orphaned wells, would cost taxpayers money. In a period of four years, from 1996 to 2000, there were reportedly 712 wells plugged in Louisiana for US$14,090,000, which is an average cost of US$17,890 per well. Presently, there is a new powerful incentive for not plugging wells that might be returned to production as the processing price of oil has reached US$56/STB with no signs of leveling or dropping in the future.

Several Interstate Oil & Gas Commission (IOGCC) and U.S. Department of Energy (DOE) surveys revealed that the oil-producing states know the number of idle wells, but are unable to estimate potential production associated with those wells. Thus, there is a need for a method for assigning economic value to those wells.

Discussion of Methodology

A method is being developed at LSU for assigning value to inactive wells. To accomplish this task efficiently within its boundaries or limitations, an expert system is being built comprising rules of logic, computations, and an algorithm for computer programming. In this paper, a generic methodology that has been conceptually developed is demonstrated by using a real case history. It was developed as a logic base for an eventual expert system.

The design of the methodology and logic relies somewhat on original work done on the "Prospector" program written in the late 1970s. Prospector was "designed primarily to assist exploration geologists in interpreting and evaluating data on specific mineralized sites or prospects[1]." The Prospector software was specifically designated for identifying ore deposits and designed "to reduce the risk of overlooking unfamiliar possibilities[1]."

In much the same way, the logic of this methodology seeks out wells and reserves that are not considered for economic development because the opportunist possibilities have been overlooked. The simple basic problem is that there is a shut-in, orphaned, or marginal well. Future plans for the well call either for plugging it, or leaving it as a shut-in/marginal well, or bringing it back to production and reasonable commerce using a new technology.

In order to attempt new technology on marginal wells, candidates must be generated. No one will make the required investment for new technology into a shut-in, orphaned, or marginal well if the potential is not known. Questions must be answered and analysis must be performed. However, analysis is time-consuming and expensive and has a distinct possibility of being a waste of time if no candidates are identified.

A decision tree for this task follows three basic rules. They are mostly common sense, but they provide excellent guidance in the development of the basic methodology. They are as follows:

- Rule One—Speed at the expense of detail initially;
- Rule Two—No multi-tasking; and,

PEER REVIEWED PAPER ("REVIEW AND PUBLICATION PROCESS" CAN BE FOUND ON OUR WEB SITE)

- Rule Three—Proceed even when there is missing information.

Methodology

Rule One: Speed at the Expense of Detail Initially

Speed must be the priority at the expense of detail, initially. This rule must be followed in order to quickly arrive at a conclusion concerning potential for success. Details come later through further study such as simulation, if needed or required.

Rule Two: No Multi-Tasking

Multi-tasking is inefficient. From experience, it is very easy to review too much at one time.

Rule Three: Proceed Even When There is Missing Information

Marginal wells and reservoirs typically are older ones, which may have had multiple operators and have inconsistent, missing, or unrecorded data.

Whatever data is available should be used and analyzed quickly. If candidates are identified based on substandard data, once it has been screened, then detailed data recovery may be performed, if warranted.

The methodology allows for interpolation, extrapolation, analogical comparisons, and assumptions in order to move forward quickly, whenever reasonable. By using consistent deductive reasoning or analogies to generate necessary data, the analysis may proceed.

Physical Steps

While adhering to the above rules, chronological physical steps are necessary for efficiency. The analysis must be performed at a reservoir level, initially. Once the reservoir is identified, the following steps should be taken:

1. Identify sources of information and data. Gather the accessible data and organize it;
2. Describe the general stratigraphy and regional structural geology;
3. Identify all productive sands and separate reservoirs within the field and prepare structural and isopachous maps[2]. Reduce focus to most likely candidates based on size if dealing with an area or field.
4. Measure the bulk volume of the candidate reservoirs;
5. Determine or assign average porosity, saturation, permeability, API gravity, viscosity, initial pressure, present pressure, bubble point pressure, initial solution gas-oil ratio, and the formation volume factors for oil and gas of each reservoir;
6. Calculate initial oil and/or gas in place;
7. Summarize the history of each well within a reservoir and separate all production and tests by well and reservoir into manageable spreadsheets to determine the oil and gas produced to present. Attempt to collect the entire history of production for each reservoir. In some cases, older production records will be difficult to obtain, and if this is the case, then concentrate on recent history going back in time only so far as is easily manageable;
8. Determine remaining oil and gas in place and determine the drive mechanism either by pressure/production analysis through material balance or analogy based on decline curves; and,
9. If remaining oil and gas is favourable, continue with more detailed analysis and economic valuation. Once the remaining oil and gas in place are identified, one can begin to analyze the potential reserves, if warranted. Based on the volumetric analysis outline above, one can identify which reservoirs deserve further analysis without considering potential reserves whatsoever. An incremental recovery of the initial oil and gas in place is the only concern. Once chosen for further study, target reservoirs and wells may be further analyzed by computer simulation, geologic modelling, physical well inefficiencies, well completion design, and/or specific implementation of a new technology.

West Delta Block 84 Field—An Example

As an example and case history for the implementation of this methodology, West Delta Block 84 Field is described. The initial evaluation of this field took only two weeks. The potential was recognized and the studies grew in detail.

West Delta Block 84 is located off the coast of Plaquemines Parish, Louisiana, near the mouth of the Mississippi River. Conoco discovered the field in 1955. It was operated by CATCO, which included working interest partners of Conoco, Chevron, and Texaco, until September 1988 when a very small independent, S. Parish Oil Co., bought out CATCO's interest and took over operations. To date, the field has produced over 10 MMSTB of oil and 21 BCF of natural gas.

Step One—Identify Sources of Information and Data

Initially, for West Delta Block 84 Field, the majority of the data was obtained from a public source, the Louisiana Department of Natural Resources (DNR). Examples of such data include:

1. Production data: reported on a lease-unit-well (LUW) basis (several wells and reservoirs may be included in one report). Information includes oil and gas production for the lease-unit-well;
2. Individual well tests: in the past, these were taken approximately every quarter, whereas now they are biannual. Information from these tests include daily production rates, gravity, flowing tubing pressures, and sometimes shut-in tubing pressures and bottomhole pressures;
3. Well histories: includes depths of perforated intervals, directional surveys, casing programs, initial tests, and other miscellaneous information;
4. Electric well logs; and,
5. Various reports filed in regard to the KF-1 reservoir waterflood. Information included various particulars and maps on the KF-1 reservoir characteristics.

Step Two—Describe the General Stratigraphic and Regional Structural Geology

Stratigraphy

The GR sand is the shallowest interval which has produced within the West Delta 84 Field. It is Bulminella 1 section, Lower Pliocene in age. It was deposited in an inner to middle neritic environment (that part of the sea floor which extends from the low tide line to a depth of 60 m or 200 ft)[3]. The KE and KF sands are Robulus E, Upper Miocene in age. The depositional environment for these sands was also middle neritic. Inner and middle neritic environments are characterized by a series of meandering channels and point bars. This type of system migrates laterally through time giving it a shingled effect and places numerous trough shaped cross-bedded sand channels in communication with one another. Permeability barriers, both complete and partial, are characteristic in this type of depositional sequence.

Structural Geology

The regional subsurface geology is defined by gentle synclines and anticlines and faulting which trend east-west. The structure dips to the west at approximately 10 degrees and is trapped to the north and south by down-to-the-south normal faults with approximate vertical displacements of 30 m or 100 ft each. Reservoir limits are defined either by its structure (oil-water and gas-oil contacts), or faulting, or stratigraphy in the form of shale-outs.

Step Three—Identify All Productive Sands and Separate Reservoirs Within the Field and Prepare Structural and Isopachous Maps

At the present time, the field contains five productive Lower Pliocene and Upper Miocene aged sands: KE, KF, GR, KP, and JM. Initial geologic and engineering studies placed the four sands into eight individual reservoirs (KEKF-1, KE-9, KE-A10, GR, KP, KE-5, KE-2, and JM) containing a total of 30 completions. Two of the sands, the KE and KF, were quickly determined to be in possible communication through deductive reasoning based on a thick channel sequence cutting through the middle of the reservoir. It was also recognized that there are numerous sands above and below these four known producing sands that have never been fully evaluated, leaving a large amount of upside potential to the acreage.

The reservoirs are trapped by structure, faulting, and stratigraphic mechanisms. Two of the reservoirs, the KE-KF-1 and the KE-A10, were waterflooded to some extent. The KE-2, KEKF-5, and KE-9 are smaller reservoirs and are set aside at this point for future assessment if more detailed evaluation is warranted based on the larger reservoirs. If the larger reservoirs do not support a more detailed study of the field, then the smaller ones are very unlikely to become productive. Focus at this point, therefore, moves to the most likely economically successful larger reservoirs within the field.

Step Four—Measure the Bulk Volume of the Candidate Reservoirs

Oil-water and gas-oil contacts were estimations based on all available data. Acre-feet of bulk reservoir volume were obtained by planimeter and use both the trapezoidal and pyramidal formulas as simply described by Craft and Hawkins[4].

Step Five—Determine Average Porosity, Saturation, Permeability, API Gravity, Viscosity, Bubble Point Pressure, Initial Solution Gas-Oil Ratio of Each Reservoir, and the Formation Volume Factors for Oil and Gas

Table 1 presents the raw, measured, or calculated data for the KEKF-1, KEA10, and GR reservoirs.

TABLE 1: Engineering data.

KEKF-1 Reservoir		
Gas gravity	0.6	
Temperature	668	Rankin
Pressure	5,950	psi
Porosity	30.5	%
Water saturation	24	%
Boi	1.6	bbl/STB
Bg	12,700	MCF/Ac-Ft
Rp	1,273	SCF/STB
KE-A10 Reservoir		
Gas gravity	0.63	
Temperature	669	Rankin
Pressure	6,005	psi
Porosity	29.2	%
Water saturation	25	%
Boi	1.66	bbl/STB
Bg	12,681	MCF/Ac-Ft
Rp	2,713	SCF/STB
GR Reservoir		
Porosity	29	%
Water saturation	25	%
Boi	1.38	bbl/STB
Rp	522	SCF/STB

Step Six—Calculate Initial Oil and/or Gas In Place

Using volumetrics, the original oil and gas in place is calculated for the KEKF-1, KEA10, and GR reservoirs. Table 2 summarizes these calculations.

Step 7—Summarize the History of Each Well Within a Reservoir and Separate All Production and Tests by Well and Reservoir Into Manageable Spreadsheets

Target reservoirs within the field originally contained 30.7 MMSTB of oil and 53.8 BCF of gas. To date, from these target reservoirs, the field has produced 9.0 MMSTB of oil (29.3% of oil in place) and 17.7 BCF of gas (32.9% of gas in place). Table 3 summarizes the historical production for the KEKF-1, KE-A10, and GR reservoirs.

Step 8—Determine Remaining Oil and Gas In Place and Drive Mechanism

KE-KF-1 Reservoir

It is determined through material balance that the KE-KF-1 is a gas cap/solution gas driven reservoir with a partial water drive through artificial waterflood[5]. Cumulative production from the

TABLE 2: Original oil and gas in place.

KEKF-1 OOIP (STB)	14,740,551
KEKF-1 OGIP (MMCF)	28,340
KE-A10 OOIP (STB)	5,639,202
KE-A10 OGIP (MMCF)	19,723
GR OOIP (STB)	11,149,731
GR OGIP (MMCF)	5,819

TABLE 3: Historical production.

KEKF-1			
Well	**Total STB**	**Total MMCF**	**Total Water**
#1	536,000	1,308	40,117
#A3	809,000	1,992	264,840
#12	49,002	962	0
#15	786,000	1,168	319,916
#A1D	2,843	3	180
#A4	442,000	474	173,766
#A11	350,000	735	795,120
#18	732,898	1,375	859,781
SL2553 #3		1	0
#A1	224,000	290	17,580
#4	663,000	2,976	51,526
#A13	43,000	48	4,140
#A5	0	0	0
Total	**4,637,743**	**11,332**	**2,526,966**
KE-A10			
Well	**Total STB**	**Total MMCF**	**Total Water**
#A10	9,273	656	655,852
#A7	504,394	1,986	38,091
#A12	370,562	989	91,219
#A6D	719,571	899	182,649
#A8D	65,321	81	18,219
Total	**1,669,121**	**4,610**	**986,030**
GR			
Well	**Total BBLS**	**Total MMCF**	**Total Water**
#10	606,837	417	258,248
#13	566,300	483	105,974
#6	1,380,785	781	1,108,384
#9AD	100,433	126	
#11D	16,872		653
Total	**2,671,227**	**1,807**	**1,473,259**

reservoir is 4.638 MMSTB, 11.3 BCF, and 2.5 MMBW. This represents 31% of the original oil in place and 40% of the original gas in place. Based on the drive type mechanism and placement of existing wells, potential reserves are in the neighbourhood of 1.4 MMSTB of oil and 8 BCF of gas.

KE-A10 Reservoir

It is determined through material balance that the KE-A10 is pressure depletion with a weak gas cap expansion driven reservoir with a partial water drive through artificial waterflood. Cumulative production from the KE-A10 reservoir is 1.7 MMSTB, 4.6 BCF, and 9.9 MMBW. This represents 30% of the original oil in place and 23.4% of the original gas in place. Based on the drive type mechanism and placement of existing wells, potential reserves are in the neighbourhood of 9.4 MMSTB of oil and 3.2 BCF of gas.

GR Reservoir

It is determined through a near constant reservoir pressure throughout the productive history of the GR reservoir that it is a strong water drive reservoir. Cumulative production from the GR reservoir is 2.6 MMSTB, 1.8 BCF, and 1.5 MMBW. This represents 23.6% of the original oil in place and 31% of the original gas in place. Based on the drive type mechanism and placement of existing wells, potential reserves are in the neighbourhood of 1.4 MMSTB of oil and 0.9 BCF of gas.

Table 4 summarizes the reserves from all of the target reservoirs.

Step 9—If Remaining Oil and Gas is Favourable, Continue With More Detailed Analysis and Economic Valuation

It is decided that a more detailed study should be made. A simple value of reserves in the ground and a discounted cash flow (DCF) valuation is used to establish the initial economic value of the project.

Methods for Evaluating Oil Projects

Value per BOE

One must simply have an estimate of the in-place reserves. This method is based on determining a regional or national experience value per barrel of oil equivalent (BOE) reserve in the ground. The unit value is then multiplied by the proven reserves. Gas reserves are converted to oil-equivalent in accordance with the ratio of currently experienced prices per MCF as compared with the price per barrel of oil. Likewise, adjustment could be made for lifting costs, taxes, and net revenue interest when appraising a property and comparing it with recent sales of slightly different properties in the local area[6].

TABLE 4: Reserves.

KEKF-1 Reservoir	
% oil recovered	31%
% gas recovered	40%
Reserves: oil, STB	1,400,000
Reserves: gas, MCF	8,000,000
Ultimate recovery: oil	41%
Ultimate recovery: gas	68%
KE-A10 Reservoir	
% oil recovered	30%
% gas recovered	23.4%
Reserves: oil, STB	947,470
Reserves: gas, MCF	3,267,826
Ultimate recovery: oil	46%
Ultimate recovery: gas	40%
GR Reservoir	
% oil recovered	23.6%
% gas recovered	31%
Reserves: oil, STB	1,410,044
Reserves: gas, MCF	944,730
Ultimate recovery: oil	36.6%
Ultimate recovery: gas	47%

Discounted Cash Flow

A discounted cash flow analysis (DCF) is another simple method for valuating an oil and gas project. However, it can take various forms. These include Net Present Value, Risked Present Worth, Three-Year Cumulative Cash, and Present Worth at 25%, as described below. Gustavson actually takes these different forms and creates a methodology for arriving at a "fair market value" by averaging these and other simple methods[7].

Net Present Value

The Net Present Value (NPV) of an investment is calculated by discounting the future net cash flows to time zero and summing them[8]. In its simplest form, the equation for net present value can be expressed as:

$$NPV = \sum_{j=0}^{L} \frac{NCF_j}{\left(1+i\right)^j} \quad \text{.......... (1)}$$

The NPV is called the "Expected Value" when the calculation includes probability numbers to consider risk in a quantitative and explicit manner[6].

Risked Present Worth

This method is based on selecting a present worth out of the reserve report utilizing a discount rate close to the prime rate. This value must be adjusted for risk. The risk is further broken down into several factors reflecting both operator risk and mechanical risk of the well.

Three-Year Cumulative Cash

This amount is determined by adding up the cumulative net revenue to the property over the first three years of production.

Present Worth at 20%

This method utilizes the net present value of the future cash flow from a property discounted at the rate of 20%.

Economic Evaluation of West Delta 84 Target Reservoirs

Using the outlined techniques, it is established that the fair market value of the target reservoirs within West Delta Block 84 is US$43.7 MM. Table 5 outlines the breakdown and calculation of this figure. At the time this analysis was performed, the range of values for oil and gas was US$26.00 to US$28.50 and US$2.50 to US$4.75, respectively.

Conclusions

1. A simple method has been developed to identify primary candidates from a pool of inactive wells (orphaned, marginal, and/or shut-in) having potentially the highest value of property.
2. The logic of this method has been demonstrated step-by-step using data from an actual field with a large number of inactive wells. The example shows effective identification of valid well candidates. The candidates should be given the lowest priority in the plugging/abandonment program and the highest priority for an improved recovery program.

TABLE 5: Fair market value.

KEKF-1 Reservoir	US$
1) Method One ($ Per BOE-in-the-ground): Method One value of property	$12,693,488
2) Method Two (return of purchase price): Method Two value of property	$24,786,324
3) Method Three (risk-disc present worth): Method Three value of property	$28,221,221
4) Method Four (20% present worth): Method Four value of property	$24,855,220
Fair market value Average of all four methods	**$22,639,063**
KE-A10 Reservoir	
1) Method One ($ Per BOE-in-the-ground): Method One value of property	$6,890,933
2) Method Two (return of purchase price): Method Two value of property	$11,313,015
3) Method Three (risk-disc present worth): Method Three value of property	$14,232,966
4) Method Four (20% present worth): Method Four value of property	$12,331,185
Fair market value Average of all four methods	**$11,192,025**
GR Reservoir	
1) Method One ($ Per BOE-in-the-ground): Method One value of property	$7,219,120
2) Method Two (return of purchase price): Method Two value of property	$8,735,369
3) Method Three (risk-disc present worth): Method Three value of property	$13,267,537
4) Method Four (20% present worth): Method Four value of property	$10,531,879
Fair market value Average of all four methods	**$9,938,476**

3. Further development of this methodology into an expert system is recommended.
4. The method is extremely time effective. Prior to using the method, there was absolutely no previous knowledge or data on West Delta Block 84. It took merely a period of two weeks of less than 40 hours per week to complete this discriminative analysis of the inactive wells.

Acknowledgements

The authors would like to acknowledge and thank IG Petroleum, LLC for permission to use their data for this paper, Mr. Paul Graham for his assistance in preparing some of the spreadsheets and volumetric calculations, and the Louisiana Board of Regents for their partial support through their grant, "Technology for Inactive Wells Valuation and Recovery of Bypassed Reserves From Water-drive Reservoirs in Louisiana."

NOMENCLATURE

STB = stock tank barrel
MMSTB = million stock tank barrels
MMBW = million barrels of water
SCF = standard cubic feet at 15.025 psi, 60˚ F
BCF = billion cubic feet
R_i = initial solution gas-oil ratio of each reservoir, SCF/STB
B_o = the formation volume factor for oil, reservoir barrels/STB
B_g = the formation volume factor for gas, reservoir cubic feet/SCF
NPV = net present value, US$
L = project life, years
NCF_j = net cash flow for the period j, US$
i = interest rate, decimal
MMUS$ = million US$

Conversion To SI Units

100˚ Fahrenheit = 37.78˚ Celsius
100˚ Rankin = -217.59˚ Celsius
100˚ Rankin = -359.67˚ Fahrenheit
1 pounds per square inch (psi) = 6.895 kilopascal (kPa)
1 foot (ft) = 0.3048 metres (m)
1 cubic foot (cf) = 0.02832 cubic metres (m^3)
1 barrel (bbl) = 0.159 cubic metres (m^3)

REFERENCES

1. DUDA, R.O., HART, P.E., BARRETT, P., GASCHNIG, J.G., KONOLIGE, K., REBOH, R., and SLOCUM, J., Development of the Prospector Consultation System for Mineral Exploration; *Final Report, USGS Contract No. 14-08-0001-15985 and NSF Grant No. AER77-04499, Projects 5821 and 6415, SRI International, Menlo Park, CA, October 1978.*
2. WHARTON J.B., Isopachous Maps of Sand Reservoirs; *Bulletin of the American Association of Petroleum Geologists, Vol. 32, No. 7, pp. 1331-1336, July 1948.*
3. AMERICAN GEOLOGICAL INSTITUTE, Dictionary of Geological Terms; *R.L. Bates and J.A. Jackson (eds), Anchor Press/Doubleday, Garden City, New York, NY, p. 571, 1976.*
4. CRAFT, B.C. and HAWKINS, M.F., Applied Petroleum Reservoir Engineering; *Prentice-Hall Inc., Englewood Cliffs, NJ, 1959.*
5. KIMBRELL, W.C., KEKF R1 Reservoir—West Delta Block 84, Plaquemines Parish, Louisiana—An Analysis and Confirmation of Bypassed Primary and Secondary Reserves; *Master's Thesis, Louisiana State University, Baton Rouge, LA, May 2002.*
6. SIMPSON, G.S., The Potential for State-of-the-Art Decision and Risk Analysis to Contribute to Strategies for Portfolio Management; *paper 77663, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, TX, September 29 – October 2, 2002.*
7. GUSTAVSON, J.B., Comparison of Methods for Determining Fair Market Values; *paper 13769, presented at the SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, TX, March 14 – 15, 1985.*
8. CHORN, L. and SHARMA, A., Project Valuation: Progressing From Certainty Through Passive Uncertainty to Active Project Management; *paper 77585, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, TX, September 29 – October 2, 2002.*

Provenance—Original Petroleum Society manuscript, **West Delta Block 84—Methodology and Analysis of a Previously Orphaned Field** (2005-235), first presented at the 6th Canadian International Petroleum Conference (the 56th Annual Technical Meeting of the Petroleum Society), June 7 - 9, 2005, in Calgary, Alberta. Abstract submitted for review December 16, 2004; editorial comments sent to the author(s) April 17, 2006; revised manuscript received May 15, 2006; paper approved for pre-press May 15, 2006; final approval July 7, 2006.

Authors' Biographies

William C. Kimbrell is a consulting registered petroleum engineer and certified professional geologist in Baton Rouge, Louisiana. He is also currently working toward a Ph.D. at Louisiana State University (LSU). His consulting business, Kimbrell and Associates LLC, provides multiple services to numerous operators within Louisiana and elsewhere. His operating company, Rapiere Resources Company, operates in south Louisiana. His research interests include bypassed oil, reservoir engineering, and risk analysis. He was the primary co-principle investigator for the Department of Energy Grant Number DE-FG22-95BC14802, "Improved Recovery From Gulf of Mexico Reservoirs," co-researcher and co-manager for the Department of Energy Grant Number FG07-89ID12842, "Development of Improved Methods for Locating Large Areas of Bypassed Oil in Louisiana," and the co-researcher and project manager for the Department of Energy Contract Number DE-AC22-92BC14831, "Assist in the Recovery of Bypassed Oil From Reservoirs in the Gulf of Mexico."

Andrew K. Wojtanowicz is the Texaco environmental chair and professor in the Petroleum Engineering Department at Louisiana State University. Dr. Wojtanowicz has held faculty positions at the New Mexico Institute of Mining and Technology and the University of Mining and Metallurgy in Krakow, Poland. A UN expert in drilling engineering, Wojtanowicz has worked as a drilling engineer, drilling supervisor, and drilling fluids technologist in Europe and Africa. He has conducted research in borehole mechanics, drilling bit modelling and optimization, drilling fluids solids control, well planning, casing design, formation damage, control of water coning, and environmental control technology for petroleum engineering. Wojtanowicz studies have been reported in 180 publications and four books. In 1992 – 1993, he worked for Conoco Inc. as an Environmental Research Fellow developing dewatering technology for closed-loop drilling systems. In 1996, Petroleum Engineer International awarded him a Special Meritorious Award for Engineering Innovation for water coning control technology with Downhole Water Sink (DWS). Since 1997, Wojtanowicz has directed a Joint Industry Project (JIP) concerning R&D and field implementation of DWS. He has also served as the 2003/2004 SPE Distinguished Lecturer of the Downhole Water Separation technology. Presently, he is an editor-in chief of ASME Transactions Journal of Energy Resources Technology. Wojtanowicz is a registered petroleum and environmental engineer in Louisiana and a petroleum engineer in Oklahoma. He holds an M.S. degree in mining/petroleum engineering, Ph.D. and D.Sc. degrees in petroleum engineering from the University of Mining and Metallurgy, and a Polish title of professor of technical sciences.