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KENTUCKY GEOLOGICAL SURVEY

UNIVERSITY OF KENTUCKY, LEXINGTON SERIES XI, 1982

Donald C. Haney, Director and State Geologist

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PROCEEDINGS OF THE TECHNICAL SESSIONS KENTUCKY OIL AND GAS ASSOCIATION FORTY-FIRST ANNUAL MEETING JUNE 15-17, 1977

In cooperation with Kentucky Oil & Gas Association

SPECIAL PUBLICATION 5

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CONTENTS

THE POTENTIAL OF THE KNOX DOLOMITE IN THE ILLINOIS BASIN FOR PETROLEUM PRODUCTION

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ABSTRACT

The petroleum of the Knox dolomite is dependent on: (1) the presence of reservoir rocks within the section, (2) the presence of barriers to fluid migration, and (3) the presence of petroleum source rocks.

Reservoir rock is indicated by the presence of secondary crystal growth on rock chips in drill cuttings, zones of oolitic chert and silicified oolites in a carbonate matrix, and sandstone stringers. The ease with which the Knox accepts injected fluids and the loss of circulation when mud is used for drilling indicate excellent reservoir properties.

Anhydrite found in drill cuttings suggests that the rock may contain beds of anhydrite which restrict upward migration of petroleum. Insoluble residue studies indicate that potassium feldspar, which occurs within the Knox, could restrict lateral and vertical migration. Also, interfingering of reservoir and nonreservoir beds could provide a barrier to fluid migration.

The Knox has been found to contain as much as 0.85 percent organic carbon by weight. Further testing remains to be done, but as much as 100 billion barrels of hydrocarbons could be contained in the Knox Megagroup.

INTRODUCTION

The Knox Megagroup includes the predominantly dolomite section of Upper Cambrian and Lower Ordovician rocks in the Illinois Basin (Fig. 1). The top of the Knox is immediately below the St. Peter Sandstone; the base is at the base of the Cambrian dolomites. Therefore, it varies from place to place, depending on the lithology of the Franconia and Eau Claire Formations. Where these units are dolomite, the Knox can be considered to include all rocks between the St. Peter and Mt. Simon Sandstones (Swann and Willman, 1961, p. 477; Willman and others, 1975). The potential of the Knox Dolomite Megagroup to produce petroleum is dependent on three rock properties essential to hydrocarbon accumulation: (1) the presence of reservoir rocks within the section, (2) the presence of barriers to fluid migration, and (3) the presence of petroleum source rocks.

RESERVOIR ROCKS

The most positive evidence of porosity and permeability in subsurface rocks is found in core samples. The few Knox cores available show porosity in a combination of vugs and fractures that, if sufficiently extensive, could accommodate a reservoir. These vugs and fractures are not clearly apparent in drill cuttings; however, the cuttings often indicate voids by the presence of secondary crystal growth on the surfaces of rock chips. Because these crystals need open space in which to grow, their presence constitutes indirect evidence of porosity and permeability. Studies of insoluble residues of the Knox indicate that well formed crystals, usually quartz and anhydrite, are common throughout the unit (Stevenson and others, 1975, p. 10).

Abundant zones of oolitic chert and silicified oolites in a carbonate matrix in the insoluble residues provide further evidence of potential reservoir rock throughout the Knox. Sandstone stringers are also common, as shown by clusters of sand grains in the residues. Although oolites and sandstones generally are not porous until acid dissolves the carbonate matrix, they can possess reservoir properties if deposition and diagenesis

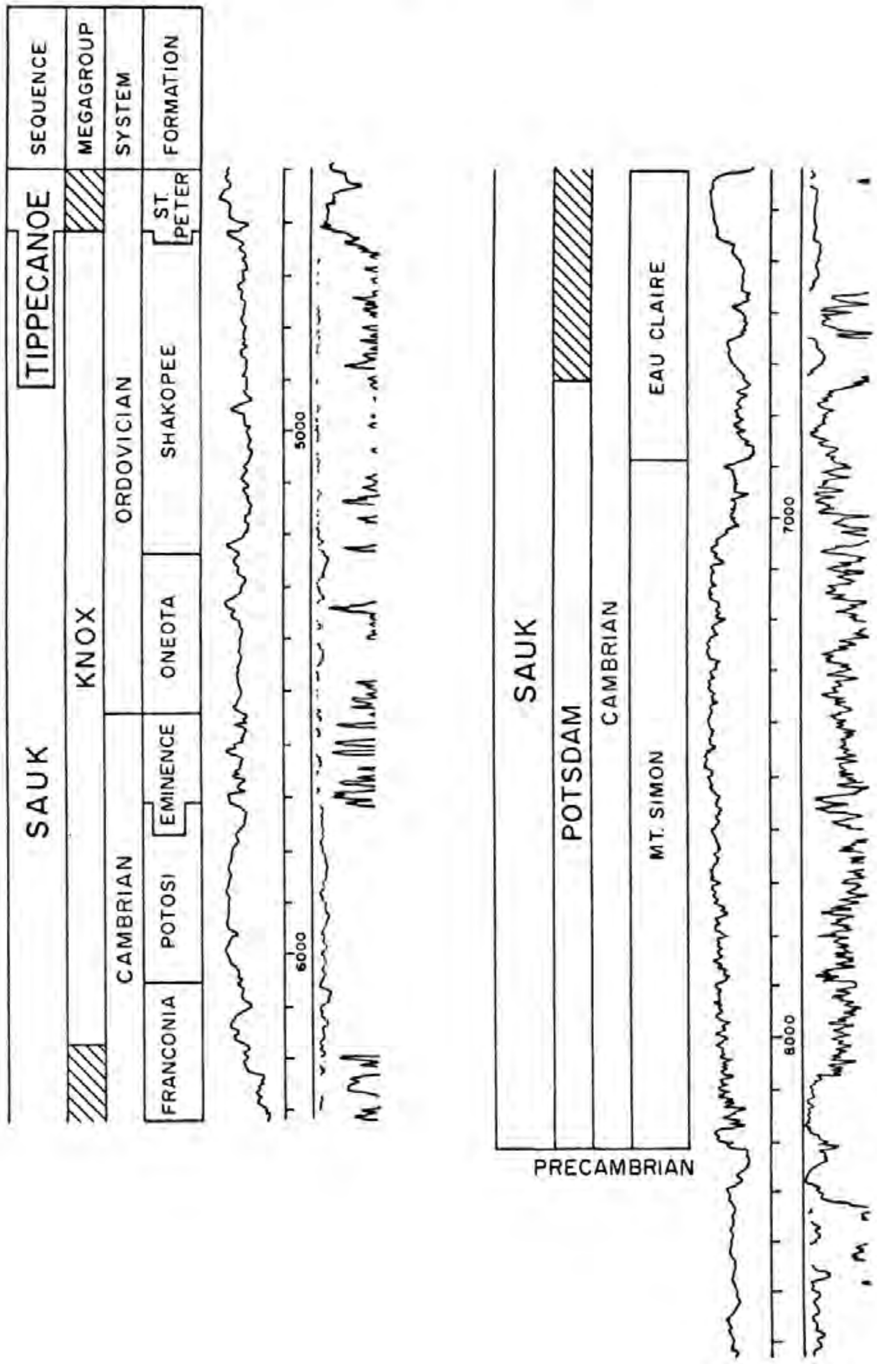

Figure 1. Stratigraphic column and electric log of Upper Cambrian and Lower Ordovician strata in the Humble No. 1 Weaber-Horn, Fayette County, Illinois. (From Stevenson and others, 1975.)

took place under favorable conditions.

A drill-stem test, another method of evaluating reservoir properties of a rock, was made of the Knox from the C. E. Brehm No. 1 Bochantin Community in Washington County, Illinois. A summary of the test follows:

DST 5,849-6,476 feet, open 1 hour
Recovered: 370 feet mud, 5,038 feet sulfur water
Bottom hole pressure: 2618 psi.

Flow pressures increased from an initial pressure of 1730 psi to a final pressure of 2596 psi. If petroleum were found there, this zone would present few production problems.

The Knox is commonly drilled with air. Sometimes water has been encountered in sufficiently large quantities to prohibit air drilling, as when Texas Pacific drilled the No. 1 Farley in Johnson County, Illinois. Texas

Pacific switched from mud to air after penetrating the top of the Knox. After drilling about 150 feet, the company was forced to revert to drilling with mud because a large amount of water flowed into the hole. The Atlantic Richfield No. 77 Lewis deep test in Lawrence County also recovered large volumes of water from the Knox; a drill-stem test of an interval from 7,484 to 7,600 feet recovered 7,037 feet of fluid, most of which was salt water.

The ease with which the Knox accepts injected fluids indicates excellent reservoir properties. A good example of this quality was at a waste-disposal well operated by the Cabot Corporation near Tuscola, Illinois. The results of two injection tests completed on an interval in the Potosi are given in Table 1. Another indication of good reservoir properties in the Knox is loss of circulation when mud is used for drilling.

Table 1.—Results of Injection Tests in a Deep Waste Disposal Well (Cabot Corporation No. 2 Cabot Tuscola, Sec. 31, T. 16 N., R. 8 E., Douglas County, Illinois).

	Pump Rate		Bottom Hole Pressure
	(bbl/min)	(gpm)	(in psi)
Test 1	3.98	167	
At start of test			2189
After 1 minute			2191
After 61 minutes			2191
Pumping stopped			
After 1 minute			2189
After 3 hours			2189
Test 2	6.80	284	
At start of test			2189
After 1 minute			2191
After 3 minutes			2200
After 61 minutes			2200
Pumping stopped			
After 1 minute			2189
After 3 hours			2189

PERMEABILITY BARRIERS

Although evidence is abundant that the Knox is porous and permeable, these properties do not exist everywhere in the unit. In some holes, such as the Texas Pacific No. 1 Streich Community test in Pope County, Illinois, the entire Knox was drilled satisfactorily with air without significant encroachment of water. A large part of the Knox is dense and tight. Some of the rock types found in the study of insoluble residues suggest that effective barriers to fluid migration exist within the dolomite. For example, abundant anhydrite was found in the Texaco No. 1 Cuppy test in Hamilton County, Illinois. The anhydrite was found in drill cuttings in sufficient quantities to suggest anhydrite beds, which restricted upward migration of any petroleum that might have been in the rocks. Brehm (1971, p. 64) suggested that a saline basin with reef and algal development may exist in the deep part of the Illinois Basin. Algal mounds with anhydrite caps could be attractive objectives for oil and gas tests.

Potassium feldspar, which is abundant in insoluble residues, could also reduce permeability in the Knox. This type of feldspar is common in Cambrian and Ordovician rocks of North America (Buyce and Friedman, 1971). Potassium feldspar, which is thought to be authigenic, occurs as very fine grains filling pore spaces of Knox dolomites and sandstones. Insoluble residue studies of the Knox indicate that potassium feldspar occurs in varying amounts and could restrict both lateral and vertical fluid migration.

Work with insoluble residues in the Illinois Basin indicates that the Knox is not a homogeneous wedge of dolomite. Figure 2 shows the location of four deep holes in or near the Fairfield Basin. These holes, listed in Table 2, are shown in the two cross sections included in a report on an insoluble residue study (Stevenson and others, 1975). The cross sections (Figs. 3 and 4) illustrate the interfingering relationship of various lithologies within the Knox. Interfingering of reservoir beds and nonreservoir beds such as sandy dolomites with shaly dolomites or porous dolomites with dense dolomites

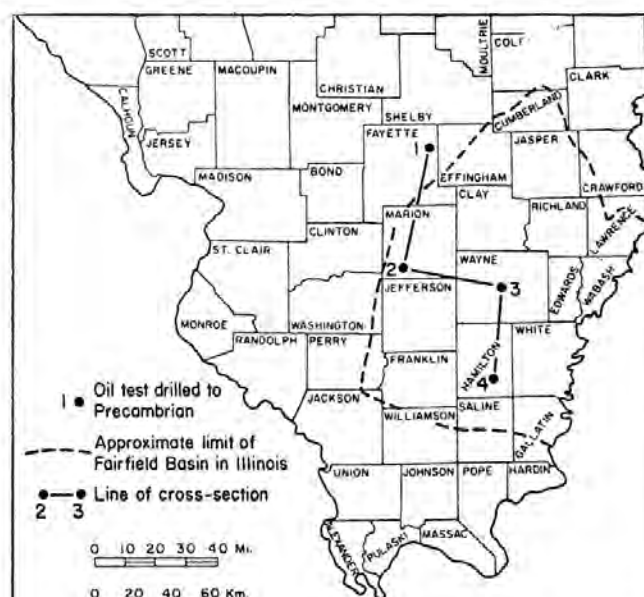

Figure 2. Location of four drill holes shown in Figures 3 and 4. (From Stevenson and others, 1975.)

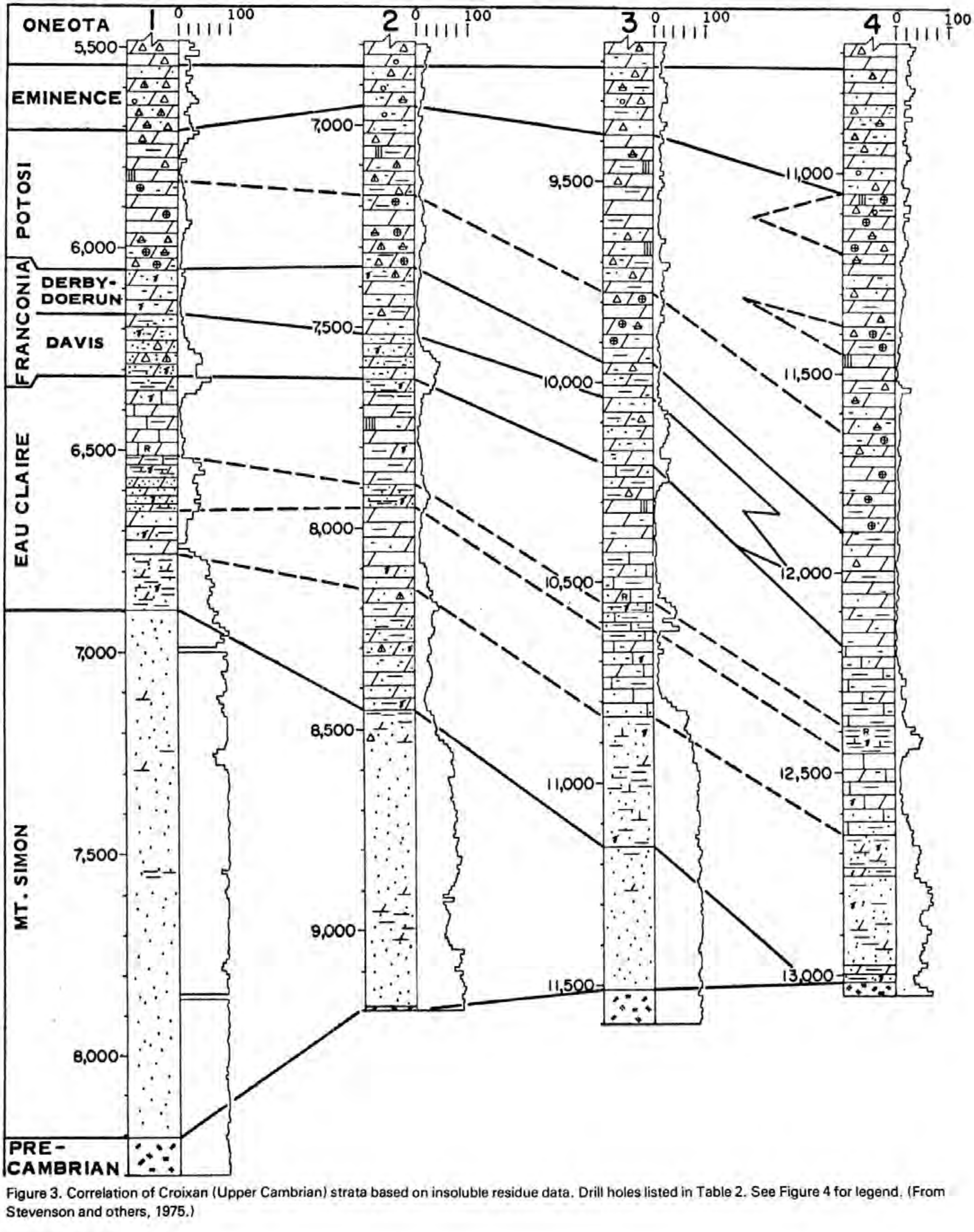

Figure 3. Correlation of Croixan (Upper Cambrian) strata based on insoluble residue data. Drill holes listed in Table 2. See Figure 4 for legend. (From Stevenson and others, 1975.)

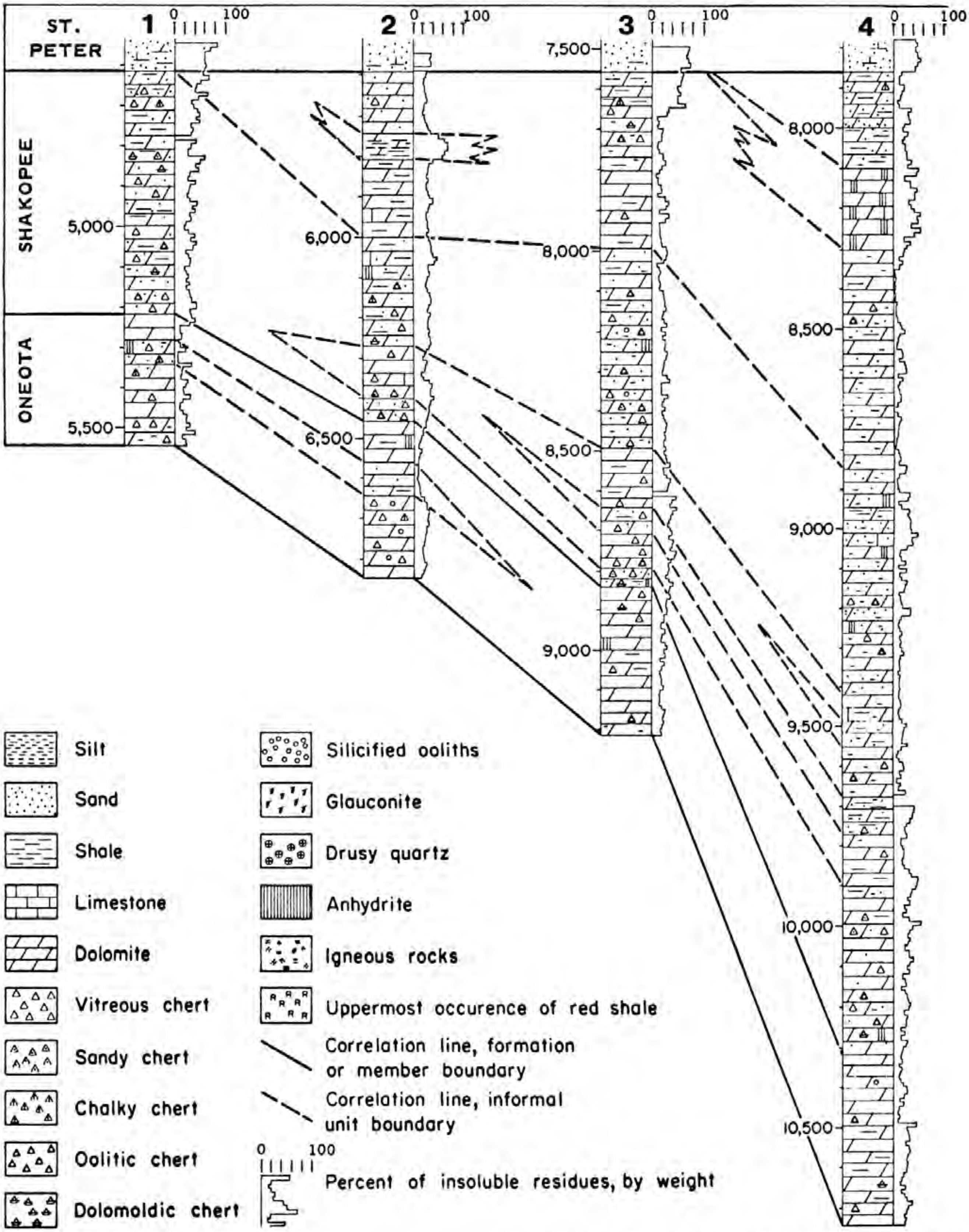

Figure 4. Correlation of Canadian (Lower Ordovician) strata based on insoluble residue data. Drill holes listed in Table 2. (From Stevenson and others, 1975.)

Table 2. — Deep Oil-Test Holes Used in Cross Sections (Figs. 3 and 4).

Hole No.	Company	Farm	No.	Sec	T.	R.	County	Total depth (ft.)	Completion date
1	Humble Oil and Refining Co.	Weaber-Horn Unit	1	28	8N	3E	Fayette	8,616	1960
2	Texaco Oil Co.	R. S. Johnson	1	6	1N	2E	Marion	9,210	1966
3	Union Oil Co. of California	Cisne Community	1	3	1S	7E	Wayne	11,614	1967
4	Texaco Oil Co.	E. Cuppy	1	6	6S	7E	Hamilton	13,051	1965

could be favorable for oil accumulation. Given this favorable association of reservoir rock and permeability barriers, the only remaining requirement for petroleum in commercial deposits is the presence of hydrocarbon-generating rocks.

PETROLEUM SOURCE ROCKS

The study of petroleum source rocks falls within the realm of organic geochemistry. A great deal of work has been done in this field, and much has been learned about the processes involved with petroleum formation, maturation, and migration. Many questions remain unanswered, however, and it is well beyond the scope of this paper to establish with any certainty that the Knox could have generated large quantities of hydrocarbons. Some analyses, the results of which were summarized by Bond and others (1971, p. 1192), show that measurable hydrocarbons are present in Knox dolomites. The Knox was found to contain as much as 0.85 percent organic carbon by weight. The same rock contained benzene-soluble organic material, much of which was in the form of hydrocarbons, in excess of 40 parts per million. If this amount of dispersed hydrocarbon is typical, then the huge volume of rock in the Knox Megagroup (30,000 cubic miles in the Illinois Basin) could contain hydrocarbons on the order of 100 billion barrels or more.

The ability of the Knox to generate hydrocarbons was strongly indicated during the drilling of a deep test in Wayne County, Illinois (Union of California No. 1 Cisne Community). A drill-stem test of a 27-foot interval in the Knox recovered 700 feet of gas, 10 feet of clean oil, and 360 feet of salt water. The interval tested was about 200 feet below the St. Peter, so the oil and gas may well have been generated in the Knox.

CONCLUSION

A great deal more work in organic geochemistry is needed before the Knox can be rejected or accepted as a petroleum source. The large volume of rock involved contains measurable hydrocarbons that could migrate along permeable courses to porous zones; potential barriers can trap and accumulate these hydrocarbons. Thus, the only deterrent to exploration in the Knox is the great expense of deep drilling through hard, cherty sections. With the constant shift of economic variables and higher prices for ever-decreasing supplies of hydrocarbons, exploration for Knox oil and gas may increase and ultimately result in commercial production from the Knox in the Illinois Basin.

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A REGIONAL VIEW OF THE KNOX

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ABSTRACT

The Knox unit extends from the Appalachian area to the Ozark Uplift in Missouri. The Knox sediments have been explored for petroleum accumulations from time to time. After more exploration, the Knox will be better understood. This greater knowledge should lead to the discovery of major accumulations of hydrocarbons in the Knox.

INTRODUCTION

The Lower Ordovician and Upper Cambrian Knox carbonate unit underlies sedimentary cover and extends from outcrops in the intensely folded and faulted Appalachian areas to outcrops in Missouri and the Ozark Uplift. In the subsurface this unit gradually increases from about 1,000 to over 7,000 feet in thickness from east to west. The maximum thickness occurs in the Reelfoot Basin of the Upper Mississippi Embayment, although the entire section of Knox has been beveled by erosion over the Pascola Arch. Here, the truncated formation subcrops beneath Cretaceous-age sediments. West of the Mississippi River the thick Knox section extends into the Arkoma Basin and is called Arbuckle, which is the equivalent of the Ellenburger of Texas.

In most areas the Knox has been subjected to subaerial erosion, which caused one of the major unconformities within the Paleozoic sediments. This unconformity delineates the upper limit of the Sauk sequence of the Paleozoic section. Above the unconformity are sandstones, such as the St. Peter and shales, limestones, and dolomites of Middle Ordovician (Chazy) age.

Within the Knox group there are local unconformities around the basin margins, but there is very little evidence of unconformities within the Knox where thick sediments occur. The base of the Knox appears to be transitional, but it is marked by the occurrence of shales and sands, which predominate the lithologic sequence, and minor carbonate units. The thickest pre-Knox sand and shale units are confined to earlier Cambrian depocenters, and growth-fault basins which were overridden by Knox carbonates.

Growth faults which produced the Rome Trough and Moorman Syncline seem to have been quiescent during Knox deposition, and reactivated at a later date in both areas.

The original lithology of the Knox was relatively shallow-water limestone with very minor amounts of sand, shale, and chert. Most of the limestones were oolitic and probably rather porous, but dolomitization and replacement chert destroyed much of the original texture and porosity. Much of the alteration occurred soon after deposition; several later periods of alteration occurred locally. The oolitic character of the formations is well preserved in the cherts, and where dolomitization is not complete the relict structure of oolites can still be seen in sample cuttings. Many of the original fossils have also been destroyed except where they have been preserved in chert or unaltered limestone. In the Ozark region there are abundant nonsilicified algal deposits. Sandy zones are also numerous, and are usually noted as "floating" grains and very thin sand streaks. The sand is of the St. Peter type: rounded and frosted grains mixed with finer grains in a bimodal distribution.

Minor constituents noted during microscopic examination of samples are chert, glauconite, anhydrite, druzy quartz, and hollow silicified ooliths; chert is the most abundant, and is found in many varieties scattered throughout the Knox. The most characteristic form is oolitic chert in which the oolites are beautifully preserved in detail. Coloration of oolites varies; there are light- and dark-centered varieties and some with alternating bands of light and dark rings. Clear grains of "floating" sand also may be seen in the chert, sometimes in association with oolites, and occasionally as the centers of oolites. Dolomoldic chert is also common and especially noticeable in insoluble residues. Occasionally very large dolomite rhombs are embedded in a very soft, chalky chert matrix. Most of the cherts are vitreous, but devitrified or chalky chert may be found separately or in association with the vitreous chert.

The insoluble forms of accessory minerals in the Knox would seem to indicate that zonation into formational units would be easily accomplished with residue studies; however, very few diagnostic forms occur, and their persistence is limited to local areas. They are not sufficiently widespread to be correlatable where deep tests are widely spaced. On outcrop in the Appalachians and in the shelf areas of Missouri and to a limited extent in Arkansas, where drilling is shallow and more closely spaced, residue studies have very successfully identified correlatable units, and as deep tests become more closely spaced residue studies offer the best means of zonation of the Knox section.

APPALACHIAN AREA

The Appalachian, or eastern, section of the Knox is subdivided into several formational units, most of which are assigned to the Beekmantown group. The top of the Beekmantown is consistent with the top of the Knox, but the bases of these two groups vary widely, and have been moved up and down so often they are no longer in agreement. The Beekmantown is now limited to rocks of Ordovician age; Cambrian units are excluded from the group. The Ordovician-Cambrian boundary is generally placed at the top of the Copper Ridge formation, and the base of the Copper Ridge is generally an acceptable base for the Knox.

In eastern Tennessee and Kentucky the Copper Ridge is the youngest Upper Cambrian formation; it overlies the Conasauga group of Late and Middle Cambrian age. The base of the Ordovician section is sometimes marked by the Rose Run sandstone, an important marker bed with a westward equivalent, the Gunter sandstone member of the Gasconade formation. The upper Knox of Ordovician age in this area is subdivided into, from youngest to oldest, the Mascot, Kingsport, Longview, and Chepultepec formations. The Chepultepec is sandy at its base, and the Rose Run sandstone probably equates with this zone.

REELFOOT BASIN

The Reelfoot Basin of the Upper Mississippi Embayment area has a much thicker section of Knox sediments preserved; more formational units named in the area reflect this thickening westward.

The stratigraphic equivalents of the Appalachian Basin and the Reelfoot Basin are shown in Table 1.

Paleontological evidence (Oder, 1934) indicates that the Mascot, Kingsport, and Longview formations are equivalent to the Cotter, Jefferson City, and Roubidoux formations. More than 2,000 feet of Knox is above the Cotter-Mascot boundary in the Reelfoot Basin. These younger Knox formations of the Powell-Smithville-Black Rock underlie the Everton and St. Peter of Chazy age. The Cambrian section also thickens into the Reelfoot Basin where the Eminence-Potosi-Elvins section may exceed 4,000 feet in thickness. Whether this increase in section represents thickening of the Copper Ridge equivalents or addition of older units such as the Bibb and Ketona at the base is unknown at this time.

Some characteristics of the Knox in wells drilled in certain areas of the Upper Mississippi Embayment area used to define formational units are:

1. The Smithville-Black Rock-Powell-Cotter section may attain 2,500 feet in thickness where it has not been removed by erosion. It is represented by dolomites and dolomitic limestones with very little chert present and occasional sandy zones. Limestones are present through much of this section in parts of Arkansas.
2. The Jefferson City formation contains oolitic limestones, and the formation has usually been only slightly dolomitized; it reaches about 500 feet in maximum thickness.
3. The Roubidoux formation is a very sandy and cherty dolomite and dolomitic limestone with an abundance of oolitic and sandy chert. Sandiness is noted at the top and bottom of the formation, which may reach 550 feet in thickness.
4. The Gasconade formation is very cherty, but there is a decrease in the sandiness from the Roubidoux formation. The basal member of the Gasconade is the Gunter sandstone, which also is used to define the base of the Ordovician System. Maximum thickness of the formation is 700 feet.

Table 1. Stratigraphic Equivalents of the Appalachian and Reelfoot Basins.

	Reelfoot Basin	Appalachian Basin
ORDOVICIAN	Smithville - Black Rock	
	Powell	
	Cotter	Mascot
	Jefferson City	Kingsport
	Roubidoux	Longview
	Gasconade (Gunter SS at base)	Chepultepec (Rose Run Sandstone)
CAMBRIAN	Eminence Potosi Elvins (Derby - Doe Run Davis)	Copper Ridge

5. The Cambrian formations form the Eminence-Potosi-Elvins group, which may combine for an overall thickness in excess of 4,000 feet. These formations are composed of dolomites with less chert than the overlying formations and a decrease in sand and chert content downward; the lower part of the section is non-sandy, and is almost lacking in chert. The typical glauconitic zones of the Elvins disappear basinward, and no clear distinction has been made between the formations where they are unusually thickened.

MOORMAN SYNCLINE

Between the Rough Creek and Pennyrile fault systems is a graben-like depression with an unusually thick Cambro-Ordovician section. Here the Knox ranges in thickness from about 4,000 to 6,000 feet. Although growth faulting can be demonstrated during Devonian and Silurian time in the Moorman Syncline, there is no evidence from the sparse deep drilling to prove or disprove movement along the bounding fault zones during the deposition of the Knox.

DEPOSITIONAL HISTORY

The vast amount of carbonate sediment that was deposited during Late Cambrian and Early Ordovician time, represented by the Knox group, is characterized by shallow-water lithologies and fossils. This carbonate material was probably derived from low-lying continental masses, and the source rocks were most likely deeply weathered, which contributed to a high concentration of minerals in solution and very little suspended material in the waters discharged from the land areas. Oolitic limestone was the predominant rock type formed; occasionally floods of sand were swept into the seas. The source areas must have been composed of sedimentary carbonates and sands, because very little clastic material was available and the sands were already mature when they were deposited in the Knox. At the beginning of Ordovician time, additional sources of sand were exposed to erosion, and the Lower Ordovician rocks received continually renewed supplies of sand. This culminated during Middle Ordovician (Chazy) time, when the very sandy Everton and the St. Peter were deposited.

The anhydrite beds found scattered throughout the Knox are of particular interest. Restricted circulation of the marine waters, lagoonal conditions, and high rates of evaporation must have provided the conditions for the formation of the anhydrite. One wonders why these beds occur most frequently west of the Cincinnati Arch in the area where open seas connected through the Arkoma Basin to the west and the marine waters were least likely to be restricted. Perhaps the area of evaporite deposition extended into the Appalachian region and was even more widespread. Evidence for this theory would be the breccia zones found in the Knox of the Appalachians; the breccias resulted from collapse of the overlying dolomite after solution and removal of evaporites.

The source of the carbonate rocks was probably from the north and east; some locally derived sediment, especially sands from the Ozark Uplift were probably included. Although the oolites probably all originated in shallow-water shelf areas, they were swept into deeper waters in areas of thick accumulation, and as the basinal areas filled, they also gradually subsided. Although some of the upper Knox was removed by erosion in the northern and eastern areas, the younger upper Knox formations of the Reelfoot Basin probably never extended much beyond their present limits.

Because the oolite banks were moving from shallow into deeper waters, time lines would diagonally cross formational units.

The Knox sediments offer a very widespread accumulation of carbonate rocks that from time to time have attracted the attention of petroleum explorationists. As more exploration is done in the areas where drilling depths are relatively shallow, the Knox sediments will become better understood, and renewed search for petroleum will undoubtedly uncover major accumulations of hydrocarbons trapped in these formations.

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EVALUATION OF COAL MINES AND COAL RESERVES

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ABSTRACT

The results of a representative financial and technical feasibility analysis of an operating surface coal mine are shown. The analysis utilizes the FINANCIAL VI computer program, which is proprietary to Dr. Charles A. Beasley, Manager, Eastern Operations, and Mr. William Jennings, Associate Geological Engineer, Robinson and Robinson Division, NUS Corporation. This summary details activities embodied in the final phases of a comprehensive, detailed investigation process, and activities requisite for a "go-no go" decision in the initial stages of property or mine evaluation.

PROGRAM DESCRIPTION

Purpose

The purpose of this paper is to describe a computer program and financial techniques which evaluate the technical and economical feasibility of proposed or existing mining operations. Two types of sensitivity analyses, which determine the effect of major cost variables and design parameters on the profitability of a venture, are also included.

The program can be used to make a "go-no go" decision based on a desired rate of return threshold, to determine the purchase price at a given rate of return, to determine the internal rate of return, and to determine the most beneficial tax structures and forms of business organization.

The program is capable of handling five separate preparation-plant or run-of-mine products, with three processing and mining recoveries for each product, and the capital structure of any venture (debt-equity ratio); annually, it can handle variable production, cash costs, non-cash costs, and taxation data. If desired, it can automatically escalate operating costs, capital costs, and product values over the life of the mine; it can automatically repurchase mine plant and equipment items at the end of their useful lives and can depreciate plant and equipment items by any of three major methods. It can also annually calculate variable loan duration and interest rates.

The program was developed to give realistic evaluation results in a form that is easy to interpret and use by engineering management. It yields a maximum amount of information so that informed feasibility judgments can be made and requires a minimum of input data. It makes maximum use of computer-plotting devices for visual presentation of tabulated results. It was written for use on the IBM 370 Model 155 using the IBM 1627-1 Digital Calcomp Plotter.

Input Data

Table 1 summarizes the data required for comprehensive feasibility determinations and both types of sensitivity analyses. Less information is required for partial analysis, and for situations in which specific data are not applicable or are unavailable.

Output

Program output includes major determinants of profitability such as: (1) present value profiles, (2) internal rates of return on equity and total investment, (3) equity payback periods, (4) annual and discounted debt service ratios, and (5) net present value to initial investment ratios. Cash-flow summaries are provided for each year of mine life. Depreciation schedules are given for each equipment item or equipment category. The annuity required for each loan repayment is given; this includes the annual principal and interest components. The present value profile and the annual and cumulative cash-flow summaries over the life of the mine may be

Table 1.—Major Input Data for Determination of Project Feasibility with Use of Sensitivity Options.

Production Data

- Reserve tonnage
- Annual production
- Mine recovery
- Preparation plant recoveries
- Initial production year
- Mine life
- Number salable products
- Preproduction period

Cost Data

- Annual development costs
- Annual exploration costs
- Property purchase price
- Royalty rate
- Annual operating costs
- Working capital requirements

Financial Data

- Capital structure
- Loan interest rate
- Loan duration
- Depletion rate
- Coal value
- Federal tax rate
- Local and state tax rate
- Loan compounding
- Discount rate increments

Depreciation Data

- Units depreciated
- Capital items depreciated
- Equipment life
- Year of purchase
- Initial depreciation year
- Purchase price
- Salvage value
- Depreciation method

Escalation Factors

- Operating cost escalation rate
- Coal price escalation rate
- Equipment price escalation rate

Options Desired

- Expense or defer development
- Expense or defer exploration
- Tonnage benefitted by deferral
- Cumulative cash flow plot
- Present value profile plot
- Return on equity and/or total
- Automatic repurchase of equipment
- Switch DB depreciation to SL

Sensitivity Analysis

- Upper variance range
- Lower variance range
- Histogram frequency
- Number ROR calculations

supplied in graphical and tabular forms. Optional sensitivity analyses allow either mutually exclusive or simultaneous variance of major cost and design parameters.

The mutually exclusive analysis allows individual variance of a single factor or several cost and design factors while holding the other factors constant. The upper and lower variance ranges are specified to the program for each parameter that is varied. The resulting rates of return that correspond to specified variances are summarized for all the parameters varied.

Since changes in one cost or design factor often cause changes in another factor because of their inherent interrelationship (for example, capital structure and interest rate, and product quality and coal recovery), provision has been made in the program for simultaneous variance of cost and design factors. The desired change in each factor is specified to the program as a mean value and variance range. The program is run the number of times specified by the user to obtain statistical validity with automatic random selection of parametric values from the specified range. The program calculates the mean rate of return, the standard deviation of profitability range, provides a histogram of output values, and tests for normality of distribution. Any combination of factors may be simultaneously varied or held constant.

CASE STUDY APPLICATION

Design Parameters

A simplistic case-study evaluation of an existing surface mine is presented to demonstrate program capability and use, and to illustrate the types of program output possible. Both types of sensitivity analyses are given in addition to the standard project feasibility.

Because of the operational status of the property, no preproduction period was required for exploration, mine development, and related activities.

Table 2 shows selected initial input values concerning mine life, production, royalty costs, tax structure, and plant and equipment data. As the table shows, no escalation of operating costs, capital costs, or coal price was assumed for the initial design situation. Variable escalation rates could have been assumed for each of these factors. Equipment salvage was taken as 10 percent of the original purchase price. The option for automatic repurchase of equipment was employed.

Table 3 shows selected mine life and cost data. It indicates the annual production exploration and development costs, capital structure, loan parameters, mining and processing recoveries, coal quality, and depletion rates. Steam coal is the only product, but metallurgical coal would have constituted a second product if it had been present. The program is not just coal oriented; consequently, it could handle up to five more components with three recoveries each and appropriate percentage depletion rates. The constancy of several parameters resulted from prior engineering analysis rather than lack of program flexibility.

PROGRAM RESULTS
Common Output

Certain output results whether or not either type of sensitivity analysis is used. It includes various profitability indices, depreciation schedules, loan repayment schedules, and the present value cumulative cash flow profiles.

Table 2. — Initial Input Values.

Mine Life	20 years, including preproduction period			
First Production Year	1			
Total Production Units	8,477,225 tons over life of mine			
Original Property Price	$10,000,000			
Royalty Cost	$0.53/production unit (ton)			
Federal Tax (1st $25,000)	20%	Operating cost escalator		0.0%
Federal Tax (2nd $25,000)	22%	Commodity price escalators	Product # 1	0.0%
Federal Tax (Over $50,000)	48%		Product # 2	0.0%
State Tax (% Of Net)	8%		Product # 3	0.0%
			Product # 4	0.0%
			Product # 5	0.0%

PLANT AND EQUIPMENT DATA

Piece Number	Price	Salvage	Description		Purchase Year	Depreciation Year	Depreciation Method	Expected Life	Resell	Escalation Rate
1	380,000	3,800	Cat 988 F.E.L. (2)		1	1	DDB/SL	10	Yes	0.0
2	380,000	3,800	Cat 988 F.E.L. (2)	(R)	11	11	DDB/SL	10	Yes	0.0
3	114,000	1,140	Cat 980 F.E.L. (1)		1	1	DDB/SL	10	Yes	0.0
4	114,000	1,140	Cat 980 F.E.L. (1)	(R)	11	11	DDB/SL	10	Yes	0.0
5	700,000	7,000	769 Truck (4)		1	1	DDB/SL	10	Yes	0.0
6	700,000	7,000	769 Truck (4)	(R)	11	11	DDB/SL	10	Yes	0.0
7	1,000,000	10,000	Cat D9 Dozer w/rip	(4)	7	7	DDB/SL	10	Yes	0.0
8	350,000	3,500	769 Truck (2)		7	7	DDB/SL	10	Yes	0.0
9	50,000	500	Tipple		1	1	DDB/SL	20	Yes	0.0
10	500,000	0	Cat D9 Dozer w/rip		4	4	DDB/SL	4	No	0.0
11	500,000	0	Cat D9 Dozer w/rip (2(R)		8	8	DDB/SL	4	No	0.0
12	500,000	0	Cat D9 Dozer 2/rip (2(R)		12	12	DDB/SL	4	No	0.0
13	500,000	0	Cat D9 Dozer 2/rip (2(R)		16	16	DDB/SL	4	No	0.0
14	190,000	0	Cat 988 F.E.L. (1)		4	4	DDB/SL	4	No	0.0
15	190,000	0	Cat 988 F.E.L. (1)	(R)	8	8	DDB/SL	4	No	0.0
16	190,000	0	Cat 988 F.E.L. (1)	(R)	12	12	DDB/SL	4	No	0.0
17	190,000	0	Cat 988 F.E.L. (1)	(R)	16	16	DDB/SL	4	No	0.0
18	195,000	0	Trucks (3)		4	4	DDB/SL	4	No	0.0
19	195,000	0	Trucks (3)	(R)	8	8	DDB/SL	4	No	0.0
20	195,000	0	Trucks (3)	(R)	12	12	DDB/SL	4	No	0.0

Used equipment is currently on property. Value of equipment is appraised.

Table 3. – Selected Mine Life Data.

Year	Annual Production	Exploration Cost	Development Cost	Equity	Loan Interest	Loan Life	Net Depletion	Mining Recovery	Product One Prod. Price	Product One Grade	Product One Coal Rec 1	Product One Coal Rec 2	Product One Gross Depletion
1	458333	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
2	458333	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
3	458333	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
4	417775	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
5	417778	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
6	417778	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
7	417778	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
8	417778	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
9	417778	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
10	417778	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
11	417778	0	0	1.0	.10	10	.50	1.0	22.00	1.00	0.9	1.0	.10
12	417778	0	0	1.0	.10	9	.50	1.0	22.00	1.00	0.9	1.0	.10
13	417778	0	0	1.0	.10	8	.50	1.0	22.00	1.00	0.9	1.0	.10
14	417778	0	0	1.0	.10	7	.50	1.0	22.00	1.00	0.9	1.0	.10
15	417778	0	0	1.0	.10	6	.50	1.0	22.00	1.00	0.9	1.0	.10
16	417778	0	0	1.0	.10	5	.50	1.0	22.00	1.00	0.9	1.0	.10
17	417778	0	0	1.0	.10	4	.50	1.0	22.00	1.00	0.9	1.0	.10
18	417778	0	0	1.0	.10	3	.50	1.0	22.00	1.00	0.9	1.0	.10
19	417778	0	0	1.0	.10	2	.50	1.0	22.00	1.00	0.9	1.0	.10
20	417778	0	0	1.0	.10	1	.50	1.0	22.00	1.00	0.9	1.0	.10

Profitability Indices

Table 4 shows the tabulated present value profile for equity and the corresponding ratios of net present value to initial investment. It illustrates both the continuous and discrete discounted cash-flow methods. The continuous method assumes all income and expenditures occur

Table 4.—Present Value Profile and Ratio of Present Value to Initial Investment.

CONTINUOUS CASH FLOWS

Equity Rate of Return	Present Value (million dollars)	Ratio of Present Value to Total Equity In First 3 Years
1.0	30.28	2.44
2.0	26.50	2.14
3.0	23.32	1.88
4.0	20.51	1.65
5.0	18.05	1.45
6.0	15.90	1.28
7.0	14.00	1.13
8.0	12.33	0.99
9.0	10.85	0.87
10.0	9.53	0.77
11.0	8.36	0.67
12.0	7.31	0.59
13.0	6.37	0.51
14.0	5.53	0.45
15.0	4.77	0.38
16.0	4.08	0.33
17.0	3.46	0.28
18.0	2.89	0.23
19.0	2.38	0.19
20.0	1.91	0.15
21.0	1.48	0.12
22.0	1.08	0.09
23.0	.72	0.06
24.0	.39	0.03
25.0	.08	0.01
25.3	0.0	0.0

DISCRETE (JAN. 1 AND DEC. 31) CASH FLOWS

Equity Rate of Return	Present Value (million dollars)	Ratio of Present Value to Total Equity In First 3 Years
1.0	29.94	2.41
0.0	29.93	2.09
3.0	22.45	1.81
4.0	19.43	1.57
5.0	16.79	1.35
6.0	14.47	1.17
7.0	12.44	1.00
8.0	10.64	0.86
9.0	9.05	0.73
10.0	7.64	0.62
11.0	6.38	0.51
12.0	5.25	0.42
13.0	4.23	0.34
14.0	3.32	0.27
15.0	2.49	0.20
16.0	1.75	0.14
17.0	1.06	0.09
18.0	.44	0.04
18.8	0.0	0.0

uniformly over each year. The discrete method assumes all expenditures occur at the first of the year and all proceeds accrue at the end of the year. The discrete method is obviously more conservative. The net present value for the continuous method varies from zero at the internal rate of return of 25.3 percent, to \$1.9 million at a 20 percent rate of return. The corresponding ratio of net present value to initial investment varies from 0.0 at the internal rate of return, to 0.15 at a 20 percent rate of return.

The equity payback period is 7.0 years at a return of 25.3 percent (Table 5). Since 100 percent equity was assumed for the initial design situation, the total investment profiles and returns are identical to those for equity. Figure 1 shows the plot of the present value profiles and the ratio of present value to total equity.

Table 5. — Equity Rates of Return and Payback Period.

Equity Rate of Return (Continuous) is 25.29
Equity Rate of Return (Discrete) is 18.79
Equity Payback Period is 7.00 years

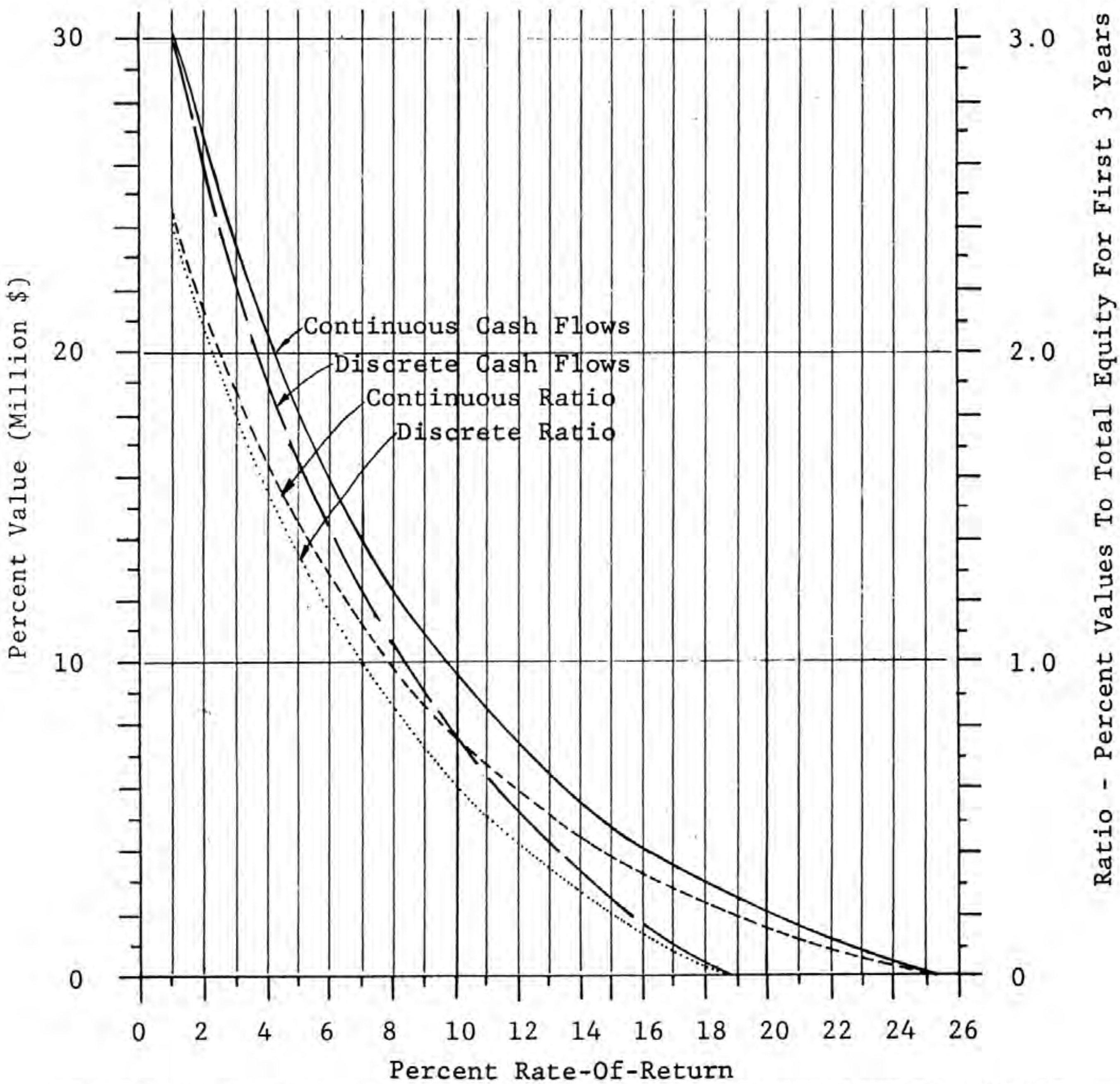

Figure 1. Graph showing present value profile, continuous and discrete cash flow methods, and ratio of present value to total equity.

Cash Flow Summaries

Table 6 shows example annual cash-flow summaries that are output for each year of mine life. The annual production, coal price, and gross revenue are shown. Cash and non-cash costs are itemized. Net cash inflow from operations is determined after calculation of appropriate Federal and local taxes. Expenditures can be shown for exploration, development, plant and equipment, and working capital. The amounts of equity and debt capital required annually are indicated, based on the assumed debt-equity ratio. Since the standard case

Table 6. – Annual Cash Flow Summaries and Mine Life Total.

	1	2	3*	19	20	Total
Production						
Annual Production	458333	458333	458333	417778	417778	8477225
Average Value	19.8	19.8	19.8	19.8	19.8	19.8
Gross Revenue	9074993.	9074993.	9074993.	8272004.	8272004.	167848976.
Cost and Deduction						
Royalty	242916.	242916.	242916.	221442.	221422.	4492923.
Operating Cost	3972372.	3972372.	3972372.	3899122.	3899122.	78202160.
Depreciation	291800.	272340.	250982.	370817.	229499.	9858408.
Expensed Development	0.	0.	0.	0.	0.	0.
Deferred Development	0.	0.	0.	0.	0.	0.
Expensed Exploration	0.	0.	0.	0.	0.	0.
Loan Interest	0.	0.	0.	0.	0.	0.
Net Income Bef. Taxes and Depl.	4587906.	4587366.	4608744.	3780643.	3921962.	75495408.
Total State & Local Taxes	385432.	366989.	368699.	302451.	313757.	6039632.
Net Taxable for Federal Purposes	4292473.	4220376.	4240044.	3478191.	3608205.	69455744.
Percentage Depletion	883208.	883208.	883208.	805058.	805058.	16335608.
Cost Depletion	0.	0.	0.	0.	0.	0.
Tax Loss Carried Forward	0.	0.	0.	0.	0.	0.
Federal Income Tax	1593247.	1601840.	1611281.	1283103.	1345509.	25497648.
Investment Tax Credit	132400.	8000.	8000.	0.	0.	632793.
Net after Tax Income	1858418.	1743328.	1753555.	1398829.	1457637.	28255248.
Additional Income	0.	0.	0.	1200.	26140.	69580.
Adjusted Net	1858418.	1743328.	1753555.	1391229.	1483777.	28324838.
Addback of Non-Cash Costs						
Total Addback, Including Depr. Depl. Expl. Dev. Losses Carried Fwd. & Exp Adv Roy	1175007.	1155547.		1175875.	1034557.	25993968.
Net Cash Inflow from Operations	3033424.	2898874.	2887723.	2567104.	2518333.	54318800.
Expenditures						
Original Purchase Price	10000000.	0.	0.	0.	0.	10000000.
Exploration	0.	0.	0.	0.	0.	0.
Development	0.	0.	0.	0.	0.	0.
Plant and Equipment	1364000.	120000.		120000.	120000.	9728000.
Working Capital	812500.	0.	0.	0.	0.	0.
Net Cash Flow Bef. Loan Prin Paym	9143076.	2778874.	2767723.	2447104.	3210833.	34590880.
Loan Principal	0.	0.	0.	0.	0.	0.
Loan Funds	0.	0.	0.	0.	0.	0.
Equity Funds	12176500.	120000.	120000.	120000.	-692500.	19727968.
Annual Net Cash Flow	3033424.	2898874.	2887723.	2567104.	2518333.	54318800.
Total Equity	12176500.	12296500.	12416500.	20420480.	19727968.	19727968.
Total Loan	0.	0.	0.	0.	0.	0.
Total Investment	12176500.	12296500.	12416500.	20420480.	19727968.	19727968.

*Truncated for Clarity.

involved 100 percent equity, no entries are shown for either the debt capital or the associated interest expense items. Later sensitivity testing of the capital structure, however, included consideration of these items. The negative amounts shown for the working capital in the final years of mine life result from withdrawal of venture working capital. The annual summaries have been truncated for illustrative purpose.

Depreciation Schedules

Depreciation schedules are output for all equipment and capital cost items specified to the program. Those items or categories that are automatically repurchased are indicated. The number of repurchases required is a function of equipment life relative to mine life.

Cumulative Cash Flow Plot

A plot of the cumulated cash flow for the life of the mine can be obtained. No consideration is given to the time value of money since the plot is of absolute annual values. It illustrates the negative cash flows experienced in the preproduction stages, the break-even point at which the cumulative income equals the cumulative cash outflow, and the total to which the flows build over the life of the mine.

Sensitivity Analyses

Single Parameter Variance

Early in the evaluation process it is essential to identify those critical cost and design items whose accuracy most greatly affect venture profitability. Additional efforts can then be concentrated on critical items, with decreased emphasis on less important items.

For illustrative purposes, five cost and design parameters were varied over their likely range of occurrence to determine their effect on profitability. Those parameters were: variable operating costs, commodity price level, plant and equipment costs, productive capacity, and preparation plant recovery. Results of the variance are tabulated in Table 7 and graphical plots are presented in ures 2 through 6. Additional parameters may be tested by either equating them with other factors whose variance is programmable or by repetitive program runs under variable input conditions. Variables with major effects on profitability include coal price level, productive capacity, and preparation plant recovery.

It is emphasized that the relative importance of specific cost and design factors are unique for a given mine, coal quality, tonnage relationship, scale and type of mining, and processing method. Care must be taken in the analysis to specify realistic variance ranges.

Simultaneous Variance

The same parameters that were individually varied are then simultaneously varied in order to determine the mean rate of return, the corresponding standard deviation, and the probability of its occurrence.

The program requires that mean value and upper and lower variance ranges be specified by the user for each parameter to be simultaneously varied. The calculation of standard deviation for the parameter is based on the upper range only. The program is executed a statistically sound number of times, with random selection of parameter values from the specified distribution. The rates of return calculated by the program fall into a dis-

Table 7.—Rate of Return on Variance Items.

Variable	Variance Range, %	Differential Rate of Return
Variable Oper. Costs, $/Unit	- 5.0 to 15.0	5.62
Commodity Price Level, $/Unit	-10.0 to 15.0	17.81
Plant and Equipment Costs	-10.0 to 10.0	1.07
Productive Capacity, Units/Yr.	-10.0 to 10.0	7.76
Loan Interest Rate, %	0.0 to 0.0	0.0*
Loan Payback Period, Yrs.	0.0 to 0.0	0.0*
Exploration Costs	0.0 to 0.0	0.0*
State Income Tax	0.0 to 0.0	0.0*
Equity Percentage	0.0 to 0.0	0.0*
Mining Recovery	0.0 to 0.0	0.0*
Preparation Plant Recovery	- 5.5 to 5.5	7.68

*Not varied in analysis.

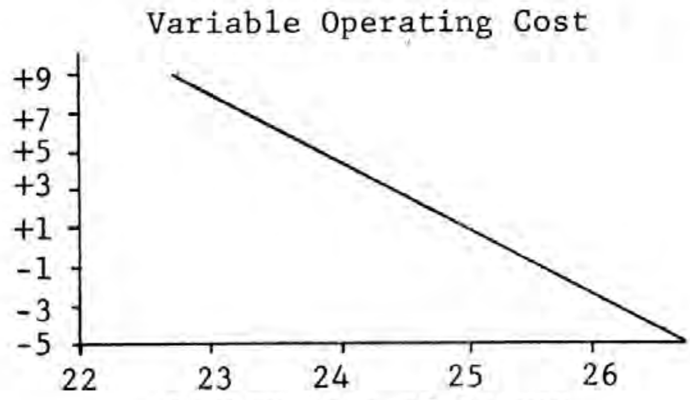

Figure 2. Graph showing variance of variable operating costs.

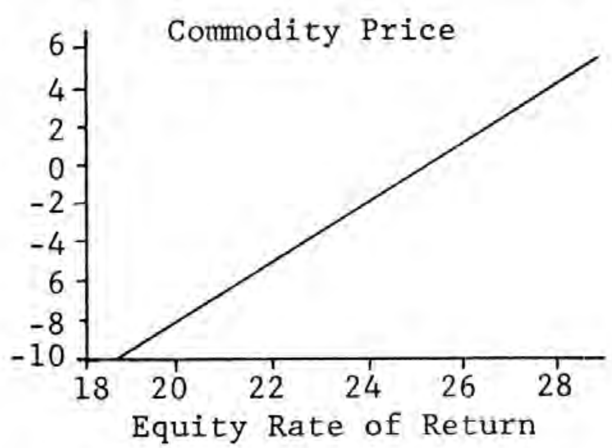

Figure 3. Graph showing variance of commodity price level.

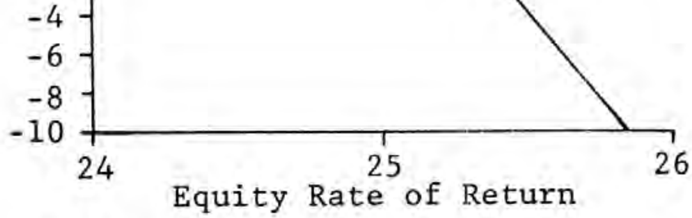

Figure 4. Graph showing variance of plant and equipment costs.

tribution whose mean and standard deviation are calculated.

Table 8 shows the individual rates of return for 30

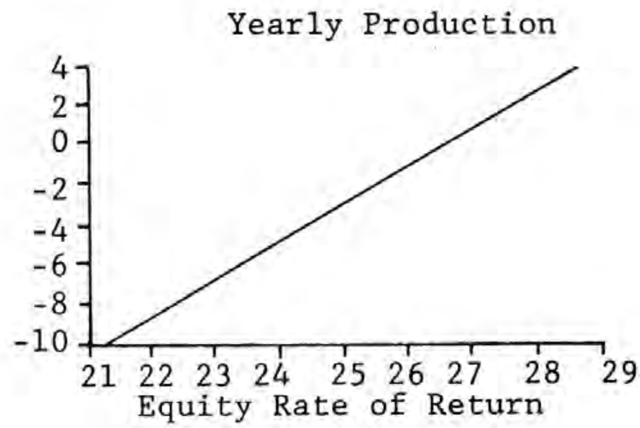

Figure 5. Graph showing variance of productive capacity.

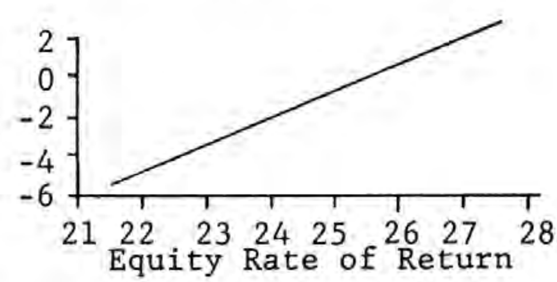

Figure 6. Graph showing variance of preparation plant recovery.

program executions. It also shows the mean rate of return on equity to be 25.06 percent, with a standard deviation of 1.63 percent. The 95 percent confidence interval of the rate of return is 21.66 to 28.62. The Kolmogorov-Smirnov test shows the data to be normally distributed, with a reasonable degree of certainty. The distribution of values is shown in Figure 7.

Special Features

The FINANCIAL VI program was originally based on the assumption that the mining venture evaluated would be the primary operation of the client company. However, in a great number of cases, the mining operation was a division of a parent corporation. As an option to the user, negative Federal income taxes can be calculated in those years in which the mine sustains a net operating loss. Losses decrease total corporate income and decrease taxes proportionately. Hence, negative taxes are really a credit to the corporation as a whole and to the mine in particular.

A strong feature of FINANCIAL VI is its simplicity of modification. Custom changes for the client can be

Table 8.—Simultaneous Variance Analysis Summary.

Analysis No.	Equity Rate of Return	Analysis No.	Equity Rate of Return
1	26.53	16	25.00
2	27.16	17	21.66
3	25.28	18	24.29
4	27.81	19	24.88
5	32.63	20	25.63
6	26.21	21	28.62
7	23.83	22	25.13
8	24.80	23	25.37
9	26.13	24	26.48
10	23.69	25	24.65
11	27.73	26	23.80
12	24.52	27	24.78
13	24.45	28	21.70
14	24.33	29	26.44
15	23.49	30	23.78

Maximum rate of return is 28.62
Minimum rate or return is 21.66
Mean rate of return is 25.06
Standard deviation is 1.63

made whenever the facts and circumstances of the economics of the mine warrent modification. Circumstances which ordinarily require modification of the program include a slightly different method of analysis; a complex royalty situation involving advance royalties, minimum royalties, or bonus; and several significant State taxes rather than one tax simply expressed in terms of net before taxes. Additionally, the program is constantly updated for changes in tax law, the most modern methods of financial analysis, and clarity of presentation.

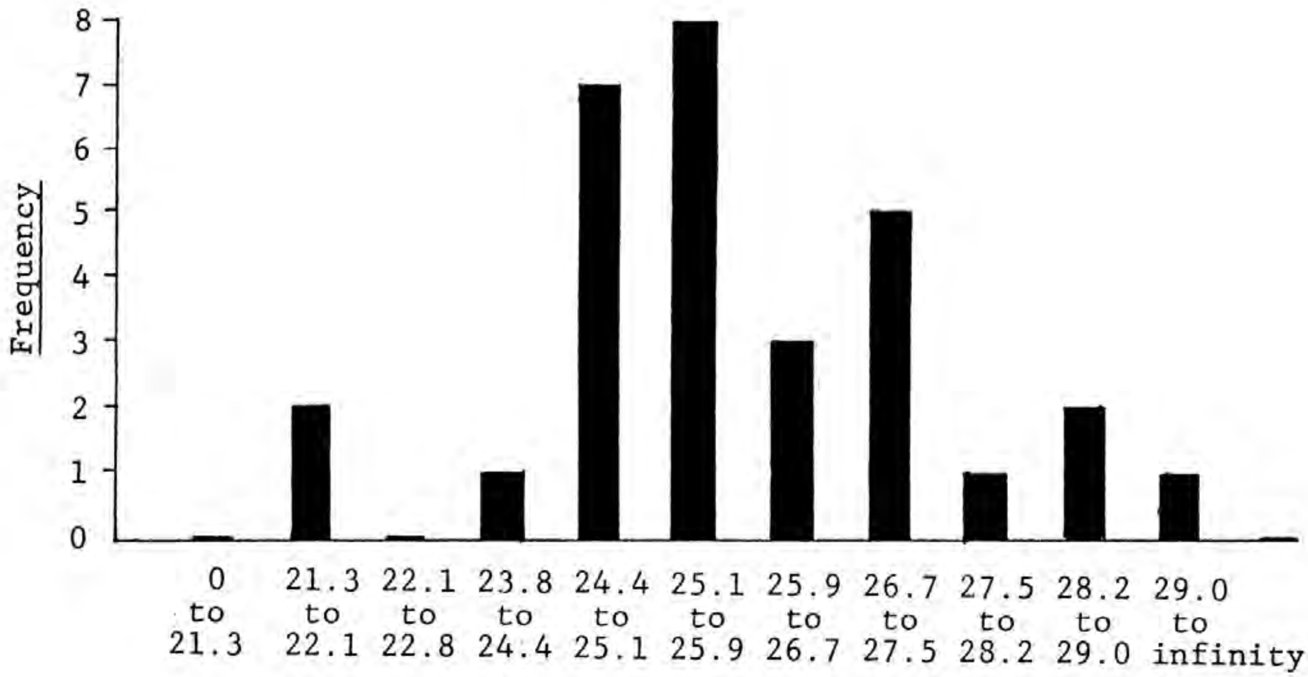

Figure 7. Graph showing distribution of simultaneous variance values (see Table 8).

STATUS AND RESULTS OF ERDA'S DEVONIAN SHALE PROGRAM

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ABSTRACT

The United States Energy Research and Development Administration's Eastern Gas Shales Project, initiated in early 1976, is a comprehensive study designed to demonstrate the benefits of developing Devonian shale gas as a major source of natural gas.

Available information indicates that large reserves of natural gas exist in the thick sequence of rocks that comprise the Devonian shales. Preliminary results indicate that the Eastern Gas Shales resource base is much larger than previous estimates have indicated. In the Appalachian Basin alone a conservative estimate computes the resource base to be 2400 TCF. If 10 percent recovery is assumed, the resulting 240 TCF of natural gas would supply our country, at the present rate of consumption, for the next 10 years.

Specific objectives of the Eastern Gas Shales Project (EGSP) are to: (1) accurately assess the magnitude of the total resource and the producible gas reserves, (2) develop advanced, economical exploration and extraction techniques, and (3) demonstrate commercial feasibility of the most promising production techniques.

Development of improved techniques for reservoir stimulation is presently in the early field-testing phase. Five successful field tests utilizing massive hydraulic fracturing to stimulate gas production from shale wells have been completed.

Detailed results and conclusions of the first year of EGSP activity will be presented at the First Eastern Gas Shales Symposium to be held in Morgantown, West Virginia, on October 17-19, 1977.

INTRODUCTION

The United States Energy Research and Development Administration's Eastern Gas Shales Project was initiated early in 1976. It is a comprehensive, multiyear project which utilizes existing technical expertise from government agencies, state geological surveys, universities, research institutes, national laboratories, and private industry. The overall goal is to demonstrate the benefits of developing Devonian shale gas as a major source of natural gas.

The Devonian shales are comprised of a relatively thick sequence of rocks that have a limited history of oil and gas production and underlie a vast area of the highly populated, industrialized eastern United States. These formations contain an abundant accumulation of natural gas that originated from the decomposition of ferns, fish, and other marine life of the Devonian seas.

Sparse information indicates that a tremendous available resource of natural gas exists within the fracture-and-matrix structure of these shale deposits, which are characterized as gray to black rocks containing tightly compacted, organic-rich clay particles. Porosity and permeability of these shales are very low; most of the pore space exists between mineral crystals or grains and in microfractures and macrofractures.

In certain areas, shale gas has been produced for over 150 years from wells that yield relatively constant rates of production for extended periods of time. However, the characteristics of and the amount of gas contained in these shales in other areas of the Appalachian, Illinois, and Michigan Basins (over 250,000 square miles) have not been adequately investigated. Thus, a prime objective of the United States Energy Research and Development Administration (ERDA) is an accurate assessment of the resource potential of these basins.

Another major aim of the project is the development of new exploration, stimulation, and production technology which will permit production of greater amounts of entrapped gas in shorter periods of time. Present developmental work for improved exploration and production involves techniques such as airborne remote sensing imagery, gravimetry, massive hydraulic fracturing, explosive fracturing, directional drilling, dual completion, and other techniques.

PROJECT ACTIVITIES

Specific objectives of the Eastern Gas Shales Project are: (1) accurately assessing the magnitude of the total resource and the available or producible gas reserves, (2) developing advanced, economical exploration and extraction techniques, and (3) demonstrating commercial feasibility of the most promising production techniques. Activities are categorized under the two major divisions of the project: (A) Resource Assessment and (B) Technology Development.

(A) Resource Assessment
1. Geochemical Characterization
2. Physical Characterization
3. Fracture Surface Studies
4. Geologic Evaluation
5. Resource Determination

Resource investigations are focused on core material obtained form various wells drilled through intervals of shale in both basins. Shale cores collected from 12 wells have yielded a total of 5,171 feet of core. Most of these cores are four inches in diameter and the interval from which the cores were collected varied from a low of 78 feet to a high of 1,308 feet. The date and location of the wells cored and the footage collected from each well are listed in Table 1.

Collection of additional shale cores during the last six months of 1977 is planned for southwestern New York, northern West Virginia, eastern and southern Ohio, eastern Tennessee, southern Indiana, and northwestern Illinois.

After coring operations, selected samples from each core are encapsulated in pressure vessels at the well site. This ''canning'' procedure is performed as soon as the core has been removed from the core barrel; the core is marked and logged to indicate depth and orientation of the particular sample. Samples are then transported to various laboratories for monitoring tests to determine pressure build-up, gas composition, and degassing rates, from which estimates of the total gas in place can be made. Physical and chemical characterization tests are also performed on these samples.

Preliminary gas testing results of a few core samples from four wells in different states are summarized in Table 2. Two different methods of determining gas content were utilized. The available, or free, gas was first measured at room temperature. Then the sample was heated and additional gas release was calculated from the subsequent sample weight loss. The availability of samples varied from well to well, so the number examined per well was not constant. A range of gas values is listed for the first three wells, from the lowest to the highest amount observed. Only one value, however, is listed for the Kentucky well, since the two samples tested were essentially the same.

Table 1.—Eastern Gas Shales Project Core Wells.

Number	Date	Location	Identification	Footage
1	1974	Carroll Co., OH	# S-745	240
2	1975	Perry Co., KY	# 7239	339
3	July 1975	Jackson Co., WV	# 11940	287
4	Nov. 1975	Jackson Co., WV	# 12041	470
5	Jan. 1976	Lincoln Co., WV	# 20403	1308
6	Mar. 1976	Lincoln Co., WV	# 20402	614
7	July 1976	Washington Co., OH	# R-109	224
8	Sept. 1976	Sullivan Co., IN	# P-1	100
9	Sept. 1976	Christian Co., KY	# KY-1-RC	149
10	Oct. 1976	Martin Co., KY	# 20336	982
11	Feb. 1977	Effingham Co., IL	# I11-1-TS	78
12	Apr. 1977	Wise Co., VA	# 20338	380

Table 2. — Calculated Shale Gas in Place, BCF per 1,000 ft x Square Mile of Shale [1].

Method of Determination[2]	Core Sites: Lincoln Co. WV	Washington Co. OH	Sullivan Co. IN	Christian Co. KY
Weight Loss (100-125°C)	500-1400	500-2900	-----	800
Free Gas (Room Temp.)	40-8080	40-110	40-140	110

[1] Battelle Columbus Laboratory

[2] The number of samples examined per well were 19, 25, 11, and 2 for West Virginia, Ohio, Indiana, and Kentucky, respectively.

Extrapolation of this data for the Appalachian Basin yields an estimated resource of 2400 TCF, based on the following assumptions: (A) 160,000 square miles in the basin, of which 60,000 square miles would be productive, (B) producible gas content of the minimum value (40 BCF per 1,000 feet x square mile) reported in Table 2, and (C) an average shale thickness of 1,000 feet. The estimated resource would therefore be computed as follows: 40 BCF x 60,000 square miles = 2400 TCF. A further assumption of at least 10 percent of the resource being producible would yield estimated reserves of 240 TCF of gas. At our country's present rate of usage, this very conservative estimate of gas reserves represents a 10-year supply. These estimates are considered preliminary and will be refined as additional data are collected and analyzed.

The remaining majority, or ''uncanned'' portion, of the core is transferred to designated state geological surveys or universities for structural and stratigraphic geological studies and mineralogical, geochemical, and physical property characterization studies.

Many samples have been obtained from these cores, and a wide variety of analyses are now being performed. Considerable geologic information has been finalized in the form of various maps and charts. For example:

1. Sixteen stratigraphic cross sections have been completed for Indiana, nine for Pennsylvania, seven for New York, plus several more for remaining parts of the basins.
2. The USGS has completed a preliminary western regional stratigraphic cross section from eastern Kentucky through eastern Ohio and northwestern Pennsylvania into southwestern New York.
3. Devonian shale well-penetration and gas-show maps have been completed for several states.

Completed phases of other studies have been documented in the form of several ERDA/EGSP publications.

Although shale gas has been produced on a limited basis for many years, better and more effective production techniques are required to properly exploit this gas resource. Investigations of this nature are programmed in the second part of the Eastern Gas Shales Project.

(B) Technology Development

1. Production and Stimulation Research and Development
2. Environmental Assessment
3. Economic Analysis
4. Exploration Research and Development
5. Field Operations
6. Modeling

Shale gas seems to accumulate in natural fractures within shale deposits. These fractures serve as reservoirs and conduits for the gas. Thus, major efforts during the early period of the project have been directed toward understanding and quantifying fracture systems. Another major effort has been developing technology for effectively connecting the wellbore with larger numbers of natural fracture systems by application of various drilling and reservoir stimulation techniques.

Various types of airborne remote sensing imagery have been investigated as techniques for mapping the location of large faults, fracture zones, and zones of high fracture density, which identify areas of likely gas production from the shale. Supplementary techniques such as borehole gravity surveys, three-dimensional reflection seismographic surveys, side-looking radar imagery, satellite imagery, and high-altitude aerial photography are being investigated.

Field demonstration projects of new stimulation concepts are in progress. The most widely tested concept to date is massive hydraulic fracturing technology, which utilizes new fracturing fluids and large volumes of fluid and sand to create long, propped fractures. A second noteworthy concept is the utilization of natural and induced fracture systems in conjunction with deviated drilling and multiple hydraulic fracturing. These technologies, plus explosive fracturing and recompletion technology offer the best potential for increasing natural gas production from the Eastern gas shales.

The primary enhanced gas recovery methods being investigated and the means of implementation are:

1. Hydraulic Fracturing
   A. New Fracturing Fluids
      1. Foam
      2. Carbon Dioxide
      3. Alcohol
   B. Large Volumes (Massive Hydraulic Fracturing)
      1. Multiple Stages
2. Deviated Wells
   A. Intersect Natural Fractures
   B. Multiple Stimulations
3. Chemical Explosive Fracturing
   A. Low Yield (Stripper Wells)
   B. High Yield (Primary Recovery)

Stimulation testing is in progress, and a few tests have been completed. Successful development of these techniques has been planned according to the schedule shown in Table 3.

Present status of this development is between items 2 and 3. A few field tests have been completed using the MHF technique, and one using the chemical explosive fracturing technique has been completed.

Two MHF test wells are presently being evaluated in Lincoln County, West Virginia, and a third is in the planning stage. The first well (Columbia Gas No. 20403) has been foam fractured in three stages at three different shale intervals. The second well (Columbia Gas No. 20402) has been fractured in two stages with water and water-foam mixtures. Data from these wells and the open-flow results are tabulated in Table 4.

Table 3.—Rationale for Reservoir Stimulation Technique Development.

1. Identification of Promising Techniques
2. Research and Development Tests
3. Field Testing
4. Combination Tests
5. Validation
6. Adoption

These results show increased gas production after every stage of MHF. The three stages of the first well resulted in gas production increases from 0 to 300 MCFD. These stages were performed in the lower Brown, middle Brown, and middle Gray shale zones, respectively. An additional stage of foam fracturing has also been scheduled for the upper Gray zone in this well; an additional increase of 100 MCFD is anticipated, which, cumulatively, would yield a total MHF stimulated production increase of 400 MCFD. This would be considered a good gas-producing well.

Only one chemical explosive fracturing test has been initiated. After fracturing, the initial open-flow rate was 150 MCFD. Only limited data are available, however, since it is still early in the testing; thus, an evaluation cannot be made at this time. A second test is scheduled for another well later in the summer.

Tests of directional drilling technology in the Cottageville, West Virginia, area have been delayed until later in the year due to delays in performing the seismic survey and prospective well-site selection.

SUMMARY

The Eastern Gas Shales Project is still in the early portion of the planned activities. Many varied and com-

Table 4.—Results from Two Massive Hydraulic Fracture Test Wells.

Well Number	Well Number	Fracture Fluid	Stabilized Open-Flow Production (MCFD) Before	After
20403	1	Foam	0	120
	2	Foam	120	200
	3	Foam	200	300
20402	1	Water	0	100
	2	Water-Foam	100	135

plex tasks are currently in progress to determine the resource potential of the Eastern shale and, simultaneously, to develop and demonstrate effective and practical means of producing the contained gas.

Preliminary results indicate that the resource base is much larger than previous estimates have indicated. The results also indicate that effective reservoir stimulation to increase gas production may be accomplished by application of massive hydraulic fracturing techniques.

Although much of the work is in progress, many of the EGSP contractors have not accumulated a sufficient amount of data for any firm conclusions to be drawn. However, at the end of this fiscal year, detailed results and conclusions will be presented at the First Eastern Gas Shales Symposium to be held in Morgantown, West Virginia, on October 17-19, 1977.

AN OVERVIEW OF MICELLAR FLOODING

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ABSTRACT

This paper is an overview of the current status of surfactant-based or micellar-polymer enhanced oil recovery processes, with particular emphasis on the Maraflood™ oil recovery process. Projected economics are included for a large-scale Maraflood™-process development in the Illinois Basin.

INTRODUCTION

Public attention has been focused on energy issues since the Arab oil embargo, and this has caused a heightened interest in techniques to recover additional oil from known reservoirs. Enhanced oil recovery (EOR) is one of the alternatives for slowing current rate of decline in United States oil production. However, EOR must be classified as emerging technology, and many questions remain to be answered. The range of applicability of most techniques is not well defined, and sufficient data are not available to allow extensive economic analyses. Because enhanced recovery technology is evolving, both its applicability and the resulting economics are subject to substantial change as the industry proceeds up the learning curve.

POTENTIAL FOR ENHANCED OIL RECOVERY

About 445 billion barrels of oil were originally in place in known United States reservoirs. Some 112 billion barrels have already been produced and another 31 billion barrels will be produced by conventional oil-field technology. This leaves more than 300 billion barrels of known oil deposits that are not now classified as reserves; they are the target for enhanced oil recovery research. A major question being asked as the United States surveys its energy options is what fraction of these 300-plus billion barrels might be amenable to EOR techniques and at what cost.

Several recent studies have attempted to answer these questions. The Gulf Universities Research Consortium (GURC), in a 1974 report to the National Science Foundation, estimated that 18 to 36 billion barrels of additional oil might be recovered from emerging recovery techniques. In April 1976, Lewin and Associates provided the Federal Energy Administration with a study of the potential in California, Texas, and Louisiana. In December 1976, the National Petroleum Council published a study on EOR potential.

Figure 1 is a comparison of the Lewin and NPC studies. The plotted incremental recovery values as a function of oil price are for the three-state case (California, Texas, and Louisiana), based on an 8 percent DCF rate of return. At $15 per barrel, these studies show additional recovery ranging from 7 billion barrels (NPC) to 36 billion barrels (Lewin). Figure 2 shows additional results of the NPC study including all 50 states (with the exception of Prudhoe Bay), with a 10 percent DCF rate of return.

Typically, studies involving EOR processes use three broad groupings: thermal, carbon dioxide, and chemical processes. Thermal processes include steam injection (cyclic and steam drive) and in-situ combustion. Chemical processes include surfactant processes (micellar-polymer, microemulsion soluble oil, etc.), polymer flooding, and alkaline flooding. High-pressure miscible gas displacement is no longer seriously considered in the United States because of gas availability. Table 1 shows the breakdown of projected recovery by process.

The GURC, Lewin, and NPC studies all could be faulted on various technical points, but their major limitations rest in their attempts to make projections in an area where technology is emerging. The results of these studies are reviewed here not to indicate the precise amount of oil that EOR processes will recover, but to show that the potential exists for such processes to recover additional oil in quantities that are very significant

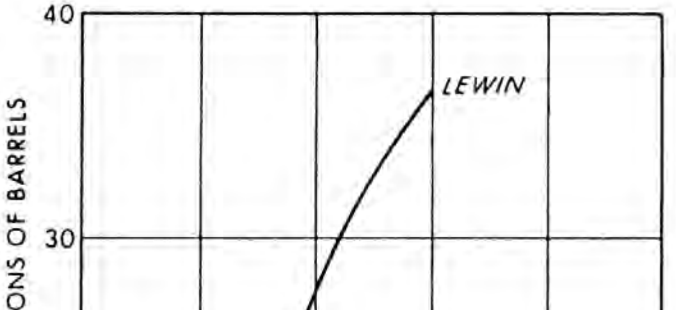

Figure 1. Graph showing incremental ultimate recovery for three states (California, Texas, and Louisiana).

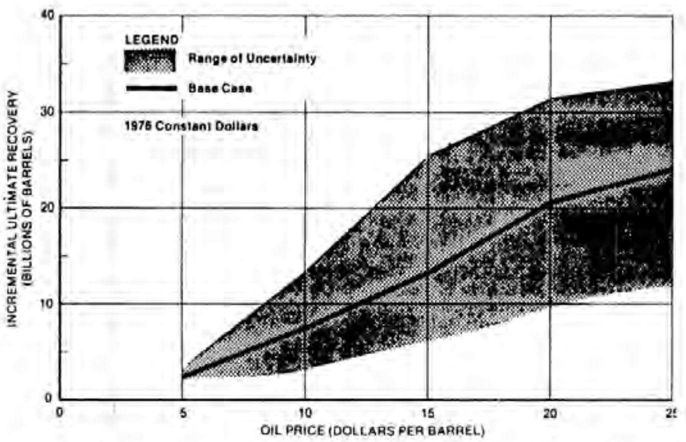

Figure 2. Graph showing range of uncertainty in incremental ultimate recovery.

Table 1.—NPC Study Projection of Recovery as a Function of Oil Price (Mimium 10% DCF ROR).

Process	Incremental Ultimate Recovery, Billions of Barrels At the Stated Crude Oil Price			
	\$10/bbl	\$15/bbl	\$20/bbl	\$25/bbl
Thermal	3.5	5.0	7.0	7.5
CO_2 Miscible	3.0	5.0	6.0	7.5
Chemical	1.0	3.0	7.5	9.0

when compared with the existing United States reserves.

STATUS OF FIELD TESTING

If there is potential for enhanced recovery technology, and specifically surfactant or micellar-polymer processes, where do we stand as an industry in proving or developing this technology?

In the early 1960's, Marathon started laboratory studies of its Maraflood™ oil-recovery process, which utilizes a relatively small slug of a surfactant-stabilized hydrocarbon-and-water blend often referred to as a micellar solution or a microemulsion. This slug is followed by a large amount of polymer-thickened water which serves as a mobility control spacer to protect the expensive micellar slug from the final drive water. The first field test of this process was initiated in 1962 in the Robinson sand, Crawford County, Illinois. Since that time, over 20 tests have been initiated or are being designed. Table 2 summarizes the results of 14 of these tests. Some of these tests are discussed in detail in other publications (Gogarty, 1970; Bleakley, 1971; Gogarty and Davis, 1972; Gogarty and Surkalo, 1972; Danielson and others, 1974; and Earlougher and others, 1975). All tests summarized in Table 2 were tertiary recovery tests (post-waterflood) except the Dedrick test. The tests encompass a variety of locations and reservoir characteristics. They include an extensive range of micellar solution design, surfactant type, mobility buffer type, and flooding pattern. In earlier tests, micellar solution was made with commercially available petroleum sulfonates. More recent tests have used internally manufactured sulfonates.

Since the initial Maraflood™ process field test in 1962, field testing philosophy and approach have continually evolved. The early tests were designed primarily to determine whether tertiary oil could be displaced

Table 2.—Summary of Maraflood™ Oil Recovery Process Field Tests.

Test	Test Dates Start	Test Dates End	Pattern Type[1]	Pattern Size Acres	Pore Volume Slug Injected (%)	Pore Volume Mobility Buffer Injected (%)	Recovery (Bbl/ac-ft)[2]
Illinois							
Dedrick	11/62	12/64	R-5	2.5	3.5	6.6	384
Wilkin	1/64	1/65	R-5	2.5	3.5	6.6	86
Henry-W	11/65	4/67	I-5	0.75	9.0	200.00	383
Henry-E 0.75 Ac	11/65	6/66	I-5	0.75	40.0	44.0	169
Henry-E 1-5 Ac[3]	6/66	6/67	I-5	1.5	20.0	83.0	205
Henry-E 3.0 Ac	6/67	6/68	I-5	3.0	10.0	55.0	159
119-R	9/68	-	LD	40.0	7.0	100.0	231
Henry-S	10/69	3/70	MT	0.2	4.8	175.0	350
118-K	9/69	12/71	R-5	2.4	3.5	87.0	200
Aux Vases	5/70	7/72	R-5	4.3	2.5	24.0	-
MT # 1	3/73	6/73	MT	0.2	7.0	93.0	284
Pennsylvania							
Bingham 533	12/68	5/71	I-5	0.75	10.0	200.00	230
Bingham Expansion	1/71	-	161-5	47.0	5.0	95.0	-
Goodwill Hill	5/71	-	91-5	10.0	5.0	95.0	-

[1]Pattern Type Codes:
R-5—Regular 5-spot, producer surrounded by 4 injectors.
I-5—Inverted 5-spot, injector surrounded by 4 producers.
MT—Mini-test, single injector, no producers.
LD—Direct line-drive pattern.
161-5—16 inverted 5-spots.

[2]Recovery or displacement in bbl per acre-ft.

[3]The Henry East pattern started as a 0.75 inverted 5-spot. It was expanded to 1.5, then 3.0 acres by shutting in old producers and opening new producers. Production data are cumulative.

and produced. Additional objectives were to investigate the importance of mobility control and slug effectiveness. After technical success was apparent, the 40-acre 119-R test was initiated to determine the amount of tertiary oil that could be removed from large-scale field development with multiple confined patterns. At the same time, mini-tests were designed to investigate process improvements. The mini-test, which requires no producing wells, has the advantage of being relatively low cost and providing results in a period of a few months. It is evaluated on the basis of saturations obtained in a coring program after the end of injection. A brief review of one mini-test illustrates the concept.

MINI-TEST 1

Mini-test 1 was located in the Robinson sand in Crawford County, Illinois. The test area had originally been developed in 1906; primary production was by solution gas drive. The field was then produced on vacuum and by air repressuring in the 1940's. In 1957, waterflooding which reduced the oil saturation in the area from 55 percent to about 40 percent was initiated.

The Robinson sand is a fluvial, Lower Pennsylvanian deposit. The top of the formation in the test area is at a depth of 975 to 980 feet, and the sand thickness averages about 30 feet in the region of the test well. Reservoir porosity averages 20 percent and the permeability ranges from about 100 to 300 md. Bottom-hole pressure and temperature at the start of the test were 50 psig and 72° F. The new reservoir crude has a viscosity of 7 cp and a gravity of 36° API.

A new fluid injection well, HWCI-1, was drilled for the test. Casing was set at 978 feet at the top of the formation. The well was completed open hole through the sand to a total depth of 1,007 feet, and equipped with a surface-recording bottom-hole pressure gauge. An existing oil well, FW-7, located 50 feet north of HWCI-1, was also equipped with a surface-recording bottom-hole gauge. It was used as an observation well for pressure response only.

The micellar solution slug used in the test contained about 70 percent water. Surfactant for the slug was manufactured in our pilot plant by sulfonating vacuum gas oil. The petroleum sulfonate was trucked to the test site. Mixing was accomplished with low-energy agitation in two 300-barrel tanks.

The "mobility buffer" or drive fluid used to propel the micellar solution slug through the reservoir was water thickened by the addition of Dow Pusher[R], a partially-hydrolyzed, high-molecular-weight polyacrylamide.

Figure 3 shows the rate and pressure behavior of the injection well, HWCI-1, and the pressure history of the observation well, FW-1. Slug injection started on October 1, 1969, and continued until October 5 at an average rate of 107 barrels per day. Total slug injection was 400 barrels.

Thickened water injection started at a rate of 105 BPD four hours after completion of slug injection. On October 14, the thickened water injection rate was increased to about 120 BPD. Polymer concentration was reduced from 1100 ppm to 700 ppm on October 24, and injection at 120 BPD resumed following a 24-hour pressure fall-off test. This rate was maintained until February, when it was gradually increased to about 160 BPD. Thickened water injection continued until March 9, 1970, when operations were terminated in order to begin coring. A total of 19,200 barrels of the polymer solution were injected.

To evaluate efficiency of oil displacement by the micellar solution, eight core tests were drilled following injection of thickened water. Figure 4 shows the location of the core tests. They were drilled on three radii extending outward from the injection well. Slug location during coring operations was 85 feet from the injection well, and is shown by the circular band. This location was determined by material balance assuming cylindrical flow, allowing for reduced effective porosity due to residual oil saturation.

The average residual oil within the slug-swept volume, determined from the core tests, was used in the calculation. No forward dispersion of slug components was assumed. Six of the core tests were drilled behind the slug front, while two cores, F and G, were drilled beyond the slug in an attempt to encounter banked oil.

Residual oil saturations determined by commercial analyses are shown in Figure 5. These analyses compare favorably with laboratory analyses using gas-liquid chromatography on the extracted oil phase.

The arithmetic average residual oil saturation (using all samples from both commercial and chromatographic analyses) found in each core test is plotted in Figure 6 as

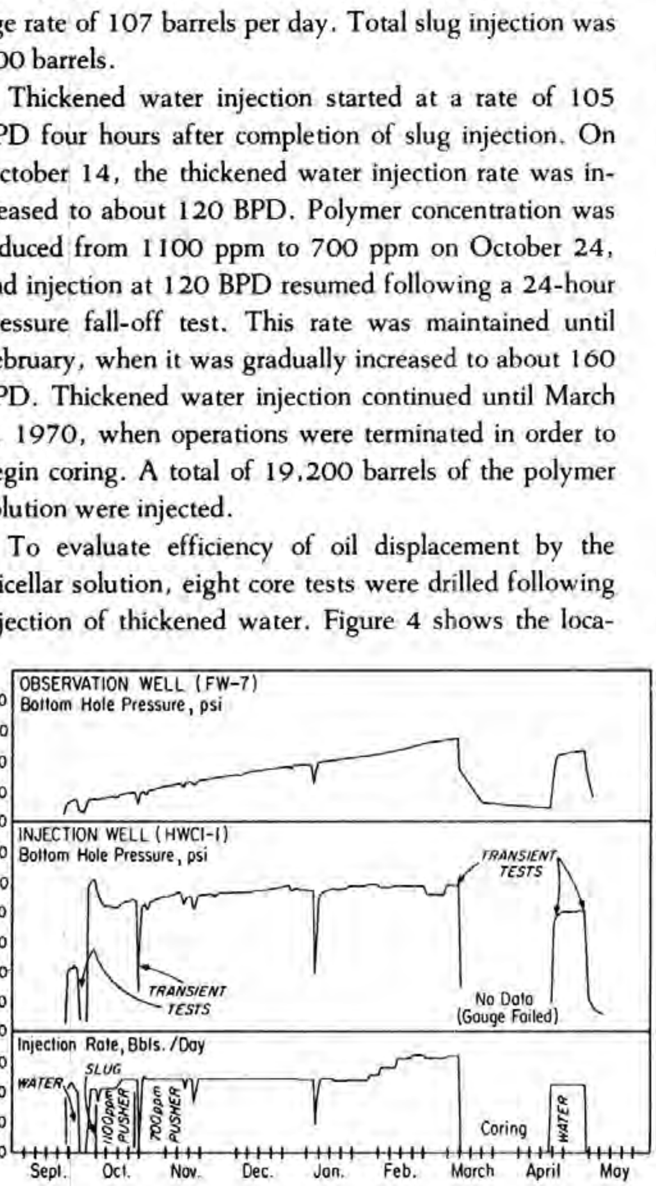

Figure 3. Graphs showing injection history of Mini-test 1.

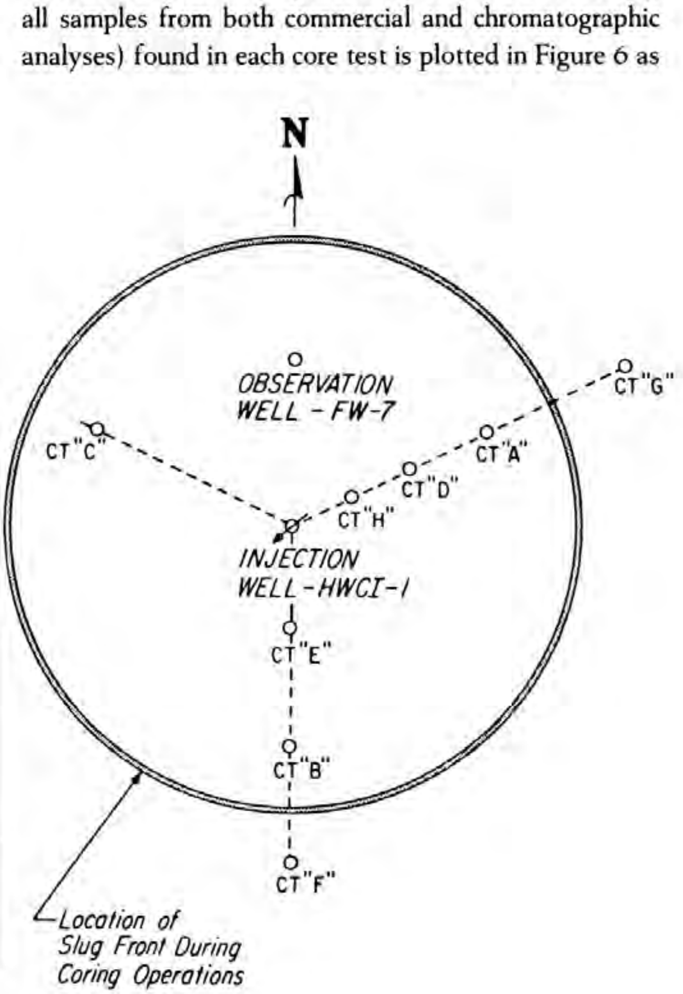

Figure 4. Location of wells and core tests for Mini-test 1.

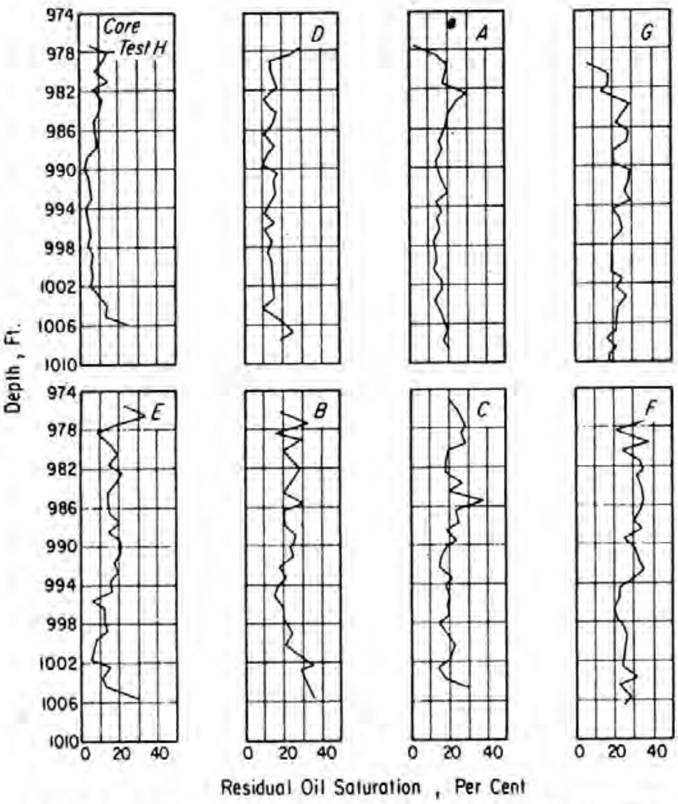

Figure 5. Graphs showing oil saturation profiles determined by commercial analyses.

a function of the distance from the injection well to the core location. Micellar solution slug removed all oil out to a radius of about 13 feet. As the slug moved farther out, it became somewhat less effective due to losses and dispersion. The residual oil saturation gradually increased, and, by about 70 feet, the slug had completely lost its effectiveness and was unable to reduce the residual saturation below that obtained by waterflooding.

Oil saturations were expected to be higher than waterflood residual behind the slug front due to the banking of oil by slug. However, as Figure 6 shows, these higher saturations were not observed in the rock taken from core tests F and G. The 29 percent oil saturation found in these cores falls within the 25 to 30 percent range found in cores taken from the Robinson area prior to micellar solution flooding. Core oil saturations are reduced to this range by the flushing action of the drilling fluid and by bleeding after removal from the hole.

119-R-PROJECT

While mini-tests can be conducted in a short period of time, and at a relatively modest cost, they cannot provide recovery data from the multiple confined patterns. The 40-acre, 119-R project in the Robinson sand, Crawford County, Illinois, was initiated to provide recovery information from a larger project.

Slug injection started in September 1968, and continued until January 1969. The total slug injection was somewhat less than 7 percent of the pattern pore volume. Thickened-water injection began in January 1969. The pattern (Fig. 7) is a direct line drive with two rows

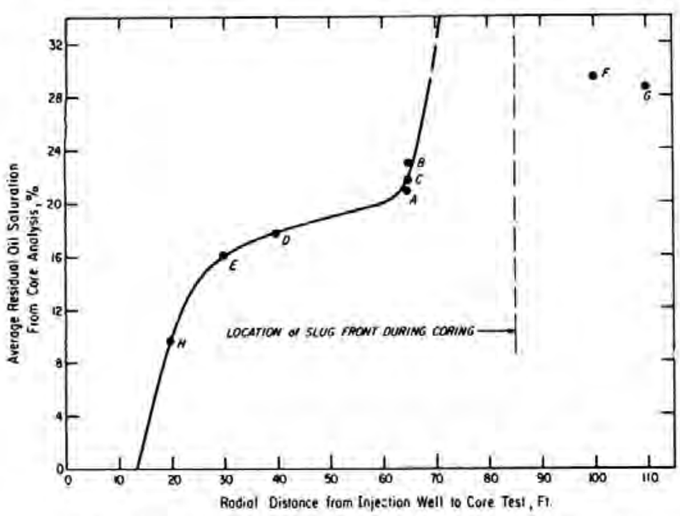

Figure 6. Graph showing average residual oil saturations as a function of distance from injection well.

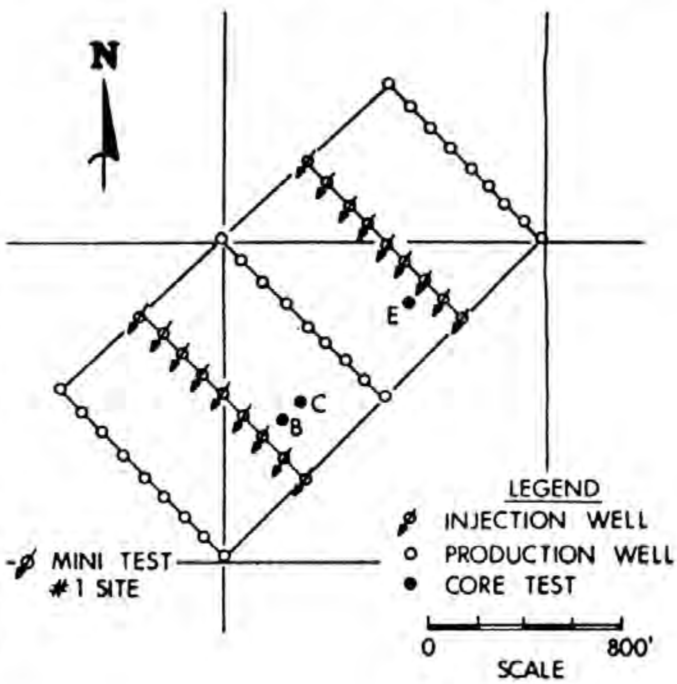

Figure 7. Illustration of 119-R test pattern.

of injection wells and three rows of producers. There are nine wells in each row, and total area enclosed by the pattern is 40 acres. Three wells in each row were old, and were drilled originally for waterflood. An average sand thickness is about 25 feet.

An objective of the 119-R test was to determine performance of the process over the distances in a 10-acre spacing. More reservoirs in the Robinson sandstone were drilled on this spacing for waterflooding. With the direct line-drive geometry shown in Figure 7, injection and production wells are 467 feet apart; this corresponds to five-spot flooding on 10-acre spacing. Distance between adjacent producers or injectors is 116 feet. This results in 2.5-acre elements; the size was planned to reduce the time for the test.

Approximately 1.5 million bbls of pore space exists within the 40-acre pattern. About 114,000 bbls of micellar solution were injected into the 18 injection wells. This slug used lease crude oil as the hydrocarbon for the first time. A mixture of crude petroleum sulfonate and commercially available sulfonates was used as the surfactant. This slug had a viscosity of about 27 to 30 cp at reservoir conditions.

Following the injection of the micellar solution, Dow Pusher[R] 700 solution was injected as the mobility buffer. The concentration of the polymer solution first injected was about 1200 ppm, but the concentration was decreased as the volume of polymer injection increased.

Figure 8 shows the production history for the project.

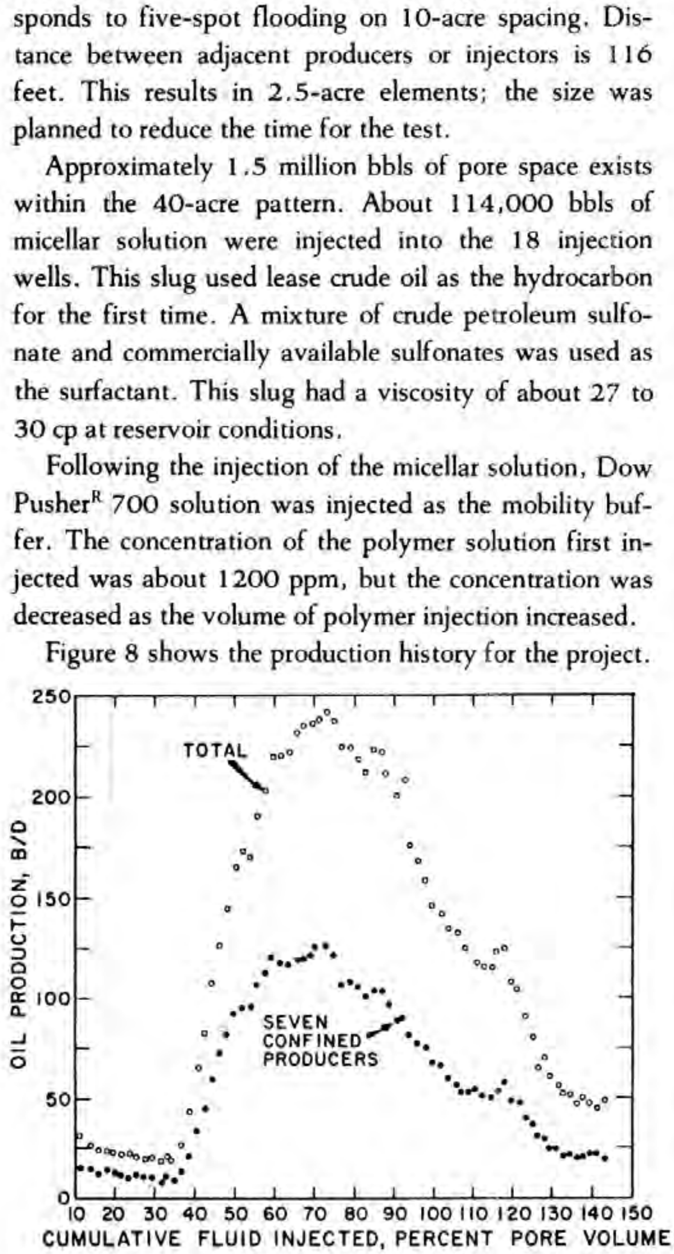

Figure 8. Graph showing oil production for 119-R project.

The cumulative fluid injected is based on estimates for the segment of the reservoir associated with the 40-acre pattern. Oil production increased from about 140 to more than 1,600 bbl per week. At the same time, oil cut increased from about 1.5 to around 20 percent.

Production from this project was about 254,000 barrels or about 231 barrels per acre-foot. As might be expected, recovery for the confined elements of the pattern was higher, running 30 to 50 barrels per acre-foot above the pattern average. Field-wide waterflood recovery for the Robinson sand was about 180 barrels per acre-foot and primary recovery was about 300 barrels per acre-foot.

CURRENT MARAFLOOD™ PROJECTS

Marathon is currently operating two Maraflood™ projects in the Robinson reservoir of Illinois. One of these is a 117-acre project developed on 2.5-acre spacing. Injection of the micellar fluid was initiated in October 1975. The project has responded and production was over 450 barrels per day by April 1977.

The second Marathon-operated project is the M-1 project. This 407-acre project contains 248 acres developed on 2.5-acre spacing and 159 acres developed on 5-acre spacing. The general location and pattern configuration are shown in Figure 9. This 43-million-dollar project is being partially funded by the Energy Research and Development Administration (ERDA). This contract with ERDA was signed in September 1976, and micellar fluid injection was initiated in February 1977.

In addition to these two Marathon-operated projects, two outside-operated Maraflood™ projects are in the design phase. Both of these projects are partially funded by ERDA, and Marathon is providing the fluid design. The Penn Grade Crude Oil Association, with Pennzoil as operator, is running a 24-acre project in the Bradford Third sand of Pennsylvania. Chemical injection should be underway on this project by midsummer 1977.

The second outside-operated project is being conducted by the city of Long Beach in the Wilmington field, California. The project is in the early design phase.

OTHER INDUSTRY TESTING

A number of other surfactant-based processes are being tested by the industry. Table 3 lists 14 new sur-

Figure 9. Marathon Oil Company commercial-scale micellar-polymer project, Crawford County, Illinois.

Table 3.—Announced Surfactant EOR Field Tests, 1976-77.

Company	Number	Area
Amoco	3	Sloss, NE; Salt Creek, Torchlight, WY
Gulf	2	Kern Bluff, Lost Hills, CA
Texaco	2	Manuel, Slaughter, TX
Gary (ERDA)	2	Bell Creek, MT
City of Long Beach (ERDA)	1	Wilmington, CA
Getty	1	Main Consolidated, IL
Phillips	1	Cut Bank, MT
Shelly	1	Velma, OK
Belco	1	Ruben, WY
Marathon (ERDA)	1	Main Consolidated, IL

factant projects that were publicly announced in 1976 and early 1977. These projects are widely distributed geographically and indicate a substantial interest in evaluating or developing surfactant recovery technology.

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION ACTIVITIES

Within the past two years, the Federal Government has taken an active role in supporting industry testing of enhanced oil recovery projects. To date, ERDA has committed some $55 million to partially fund industry-operated projects. Industry's commitment to these projects amounts to some $97 million. Table 4 is a summary of ERDA commitments in the various areas of enhanced oil recovery. Table 5 lists the seven micellar-polymer projects being partially funded by ERDA.

Table 4.—Summary of ERDA Cost-Sharing Contracts (4/77) (Dollar Numbers in Millions).

Technology	Number of Projects	ERDA Cost	Industry Cost	Total Cost
Micellar-Polymer CO_2 Flooding	7	$31.4	$52.1	$ 83.5
Improved Waterflooding Thermal Recovery	3	$ 9.0	$16.4	$ 25.4
Total	21	$55.0	$97.0	$152.0

Table 5.—ERDA Cost-Sharing Projects, Micellar-Polymer Flooding (4/77).

		Millions of Dollars	
Contractor	Location	ERDA Funding	Total Project Cost
Cities Service	Eldorado, KS	5.4	13.1
Phillips	Burbank field, OK	3.4	9.8
Penn Grade Crude Association	Bradford field, PA	2.2	4.2
Gary Operating	Bell Creek field, MT	2.5	5.0
City of Long Beach	Wilmington field, CA	3.5	7.0
Marathon	Robinson field, IL	14.0	43.0
Suntech	Marcus Hook, PA	0.4	0.4

ECONOMIC CONSIDERATIONS

Economic projections for emerging tertiary oil recovery processes such as micellar-polymer flooding are difficult to make since the industry has no experience with commercial-scale field projects. Critical factors in an economic analysis include the amount or fraction of oil recovered and the time required to recover that oil. Estimates of these parameters must now be made by extrapolating the information from laboratory models and limited small-scale field projects. Fundamental scaling laws have not been developed. Not only is scaling to large projects a problem, but field testing to date has been confined to a few reservoirs, and extrapolation to other reservoirs is even more speculative. Oil prices and tax load are as critical as recovery in making economic predictions about the viability of any tertiary recovery process. The uncertainties introduced by long-term projections of oil price and tax load significantly cloud any economic projection. Inflationary pressure on the price of goods and services also is a key factor in the ultimate economics of a tertiary recovery project.

The potential economics of applying the Maraflood™ process in southern Illinois have previously been described (Gogarty, 1975). These economic projections are summarized here.

To obtain an idea of the total cost of tertiary crude and the investment required for a large-scale development, a 6,000-acre 10-year development of the Robinson sandstone has been postulated. A 600-acre block would be drilled and developed each year for 10 consecutive years. Slug injection would take place in the year after development. Polymer solution and drive water would be injected continuously until completion in each 600-acre block. Reservoir depth is about 1,000 feet. Drilling and equipment costs are based on actual field experience. Calculations were made for both 2.5- and 5-acre spacing, with a range of recoveries. Injection rates for polymer solution and drive water were taken as 5.1 and 4.8 barrels per day per foot of sand for the 2.5- and 5-acre cases, respectively. These rates are based on waterflood experience in the area. Lower and higher injectivity rates change the project life and correspondingly increase or decrease economic parameters tied to the time value of money. The shapes of the assumed injection and oil production schedules for a 600-acre block developed on 2.5-acre spacing with a recovery of 242 barrels per acre-foot are shown in Figure 10. Schedules for the other cases were similar. Basic economic and reservoir input parameters are given in Table 6 for the cases using 2.5-acre spacing. Parameters such as the number of wells, project life, field costs, and well-operating expenses were scaled for the 5-acre spacing cases. In all calculations, an average thickness of 21 feet was

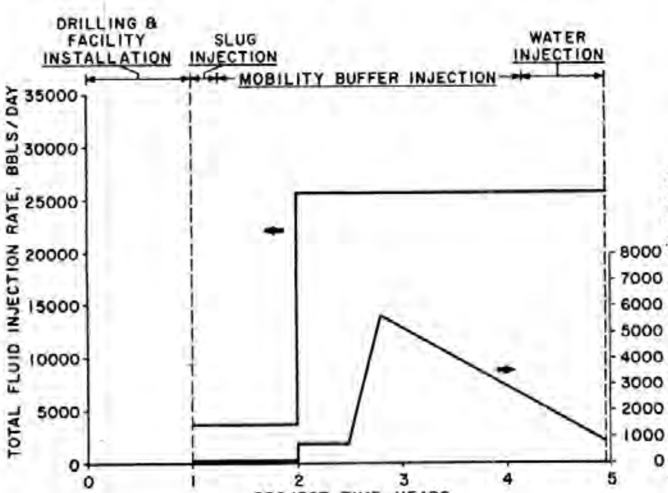

Figure 10. Graph showing projected injection and production rates for 600-acre block for Maraflood™ process in Illinois.

used for the total 6,000 acres. As with any recovery process, thicker sections improve the economics.

The economic parameters in this study are based on mid-1975 costs, and no provision is made in the analysis for escalation of either oil price or investment and operating costs with time due to inflation. Because of inflation, the costs lists in Table 6 are already outdated, but they provide an insight into the economics of the process.

Figure 11 summarizes results of calculations for three different crude prices; the two spacings with the DCF rate of return values are presented as a function of recovery of tertiary oil. All calculations are on an after-tax basis (AFIT).

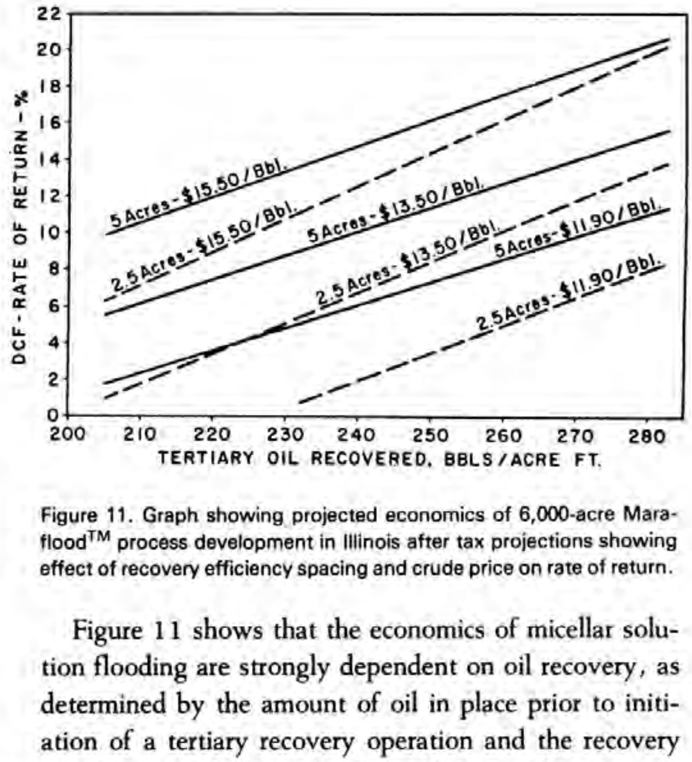

Figure 11. Graph showing projected economics of 6,000-acre Maraflood™ process development in Illinois after tax projections showing effect of recovery efficiency spacing and crude price on rate of return.

Figure 11 shows that the economics of micellar solution flooding are strongly dependent on oil recovery, as determined by the amount of oil in place prior to initiation of a tertiary recovery operation and the recovery efficiency. No large-scale projects have yet been run on which to base good estimates of recovery efficiency. The previously noted analysis of the 119-R project indicates a recovery of 230 barrels per acre-foot for the total project, with significantly higher recoveries for the confined elements of the pattern.

The actual recoveries for Robinson sandstone reservoirs will have to be determined from commercial-scale projects. The range of recoveries can be used with Figure 11 to obtain an indication of process economics. The price of stripper oil in Robinson for the first half of 1975 was $11.90 per barrel. Depending on recovery, addi-

Table 6. — Illinois 6,000-Acre Maraflood™ Process Development Basic Economic Input Parameters for Each 600-Acre Block.

Conditions:

1975 Costs and Prices
No Cost or Price Escalation with Time

Field Data:

Area = 600 Acres, Developed on 2.5-Acre Spacing
Thickness = 21.0 Feet
Porosity = 19.5 Percent
Oil Saturation = 40.0 percent (at the start of tertiary recovery operations)
Oil Cut = 3 percent (at the start of tertiary recovery operations)
Injection Wells = 240
Production Wells = 272

Fluid Injection Data:

Micellar Solution Slug = 7 percent of pore volume (slug contains 24 percent hydrocarbon-like components)
Mobility Buffer = 105 percent of pore volume
Average Polymer Concentration in Mobility Buffer = 594 Parts per Million
Drive Water Injection = 38 percent of pore volume
Project Life = 4.96 years (including 1 year drilling and site preparation)

Field Costs:

Drilling and Completion Costs = \$8,966,100
Fluid Handling and Injection Equipment = \$2,940,000
Salvage Credit = \$1,816,300
Lease Cleanup = \$1,407,400

Unit Cost:

Crude Oil Price = \$11.90/bbl
Micellar Solution Slug = \$7.69/bbl
Slug Injection Expense = 18.4¢/bbl
Polymer = \$1.02/lb
Polymer Solution Injection Expense = 4.1¢/bbl
Water Injection Expense = 2.6¢/bbl
Water Disposal Expense = 2.6¢/bbl
Well Operating Expense = \$251/well/month

Royalty and Tax Data

Royalty = 12.5 percent
Income Tax Rate = 50 percent
Investment Tax Credit = 7.0 percent (half of equipment installed will be used, thus the effective rate 3.5 percent)

tional price increases will be necessary before this type of development will be more than marginally economical at 2.5-acre spacing.

Results in Figure 11 might indicate that 5-acre spacing rather than 2.5-acre spacing would be a more economical way to develop the 6,000 acres. Actually, this will only be true if equal recoveries are obtained using both spacings. Frontal velocities will be lower with 5-acre spacing, and since recoveries decrease at the lower flooding rates, the 2.5-acre spacing may still be better. Also, slug and fluid system integrity are favored by the shorter travel distance of 2.5-acre spacing. The recovery trade-off is illustrated in Figure 11 by using the 2.5- and 5-acre curves for the \$15.50 per barrel crude price at a 14 percent rate of return. To obtain the same rate of return, the 2.5- and 5-acre development must recover 248 and 234 barrels per acre-foot, respectively.

Figure 12 indicates the influence that statutory depletion would have on the economics of enhanced oil recovery for the 2.5-acre case. The curves on this figure show the rate of return for the proposed development project as a function of oil recovery. The solid lines are for the existing zero statutory depletion case and the dashed lines assume a value of 22 percent statutory de-

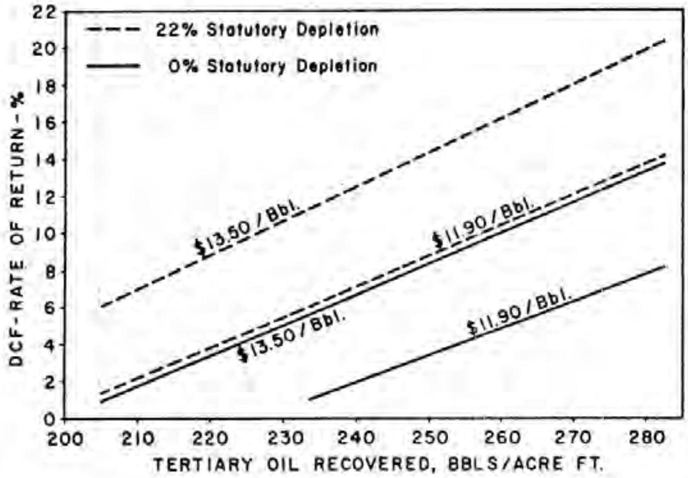

Figure 12. Graph showing projected economics of 6,000-acre Maraflood™ process development in Illinois after tax projections showing effect of recovery efficiency crude price and statutory depletion on rate of return.

pletion. To obtain a 12 percent rate of return with a crude price of $13.50 per barrel, a recovery of 272 barrels per acre-foot is required without depletion as compared with a recovery of 237 barrels per acre-foot with depletion. These values show that higher recoveries must be obtained without depletion or there must be other tax incentives if large quantities of tertiary oil are to be obtained by surfactant flooding. Alternately, Figure 12 shows that if recovery is constant, oil price must be increased without depletion for the same return on investment to be obtained.

Table 7 shows the costs associated with the projected 6,000-acre development. The values depend on oil recovery; 242 barrels per acre may or may not be typical of field recovery, but this figure was used to give an indication of expected values. With this recovery, the maximum daily production for both spacings is about

Table 7.—Illinois 6,000-Acre Maraflood™ Process Development Economic Summary.

Crude Oil Price - $11.90/bbl.

	2.5-Acre Spacing	5-Acre Spacing
Oil Recovery, bbls/ac-ft	242	242
Gross Production MM bbls	30.50	30.50
Net Production, MM bbls	27.09	27.09
Revenue, MM $	322.34	322.34
Investment, MM $	260.21	203.26
Expense	49.73	58.48
Total Cost Per Net Bbl (Before Federal Income Tax)	11.44	9.66
Project Life	13.96	17.27

8,360 barrels per day. An investment of between $203 and $260 million is required for the 6,000-acre development. Investment includes the drilling and equipment costs and the cost of injected chemicals. For the assumed recovery, the investment develops about 27 million net barrels of reserves. The total cost per net barrel as indicated in Table 7 will decrease with increased recovery, but the values given are an indication of the high cost of tertiary oil.

The calculations presented are for a project in the Robinson sandstone reservoir where there is considerable testing experience. Extrapolation or generalization to other reservoirs or conditions must be done with care and with an understanding of the uncertainties involved. Drilling and completion costs for wells are directly dependent on reservoir depth and drilling difficulties encountered in a given area. In most areas, some existing wells would be utilized in the tertiary operations. The other wells would probably be replaced, and those utilized would require remedial work. New wells may be desirable to change the flooding pattern or pattern spacing. The cost of surface facilities to mix and handle injected fluids is much less sensitive to specific reservoir selection but is influenced by well spacing or pattern density. Injected fluid costs, particularly costs of the polymer solution used as a mobility buffer, will vary depending on reservoir temperature and reservoir rock and fluid characteristics. Maraflood™ process fluids are designed to provide mobility control to prevent unstable displacement or fingering. The amount of mobility control necessary is determined by the characteristics of each specific reservoir. If more mobility control is required, more polymer must be used. These polymers are also less effective at elevated temperatures, thus more polymer is required to yield a given level of control at higher temperatures.

Micellar solution flooding requires a high initial investment, and rate of return calculations are highly dependent on project life. Project life is determined by well spacing and by the rate that fluids can be injected. Optimal well spacing is a function of reservoir thickness and depth. Spacing on 2.5 or 5 acres can be considered in shallow reservoirs of a given thickness, but such spacings will become uneconomical at greater depth. Injection rate is dependent on reservoir characteristics and depth. The nature of the reservoir rock, crude oil properties, and the character of the formation water all have a strong influence on the recovery efficiency of a micellar solution; these factors must be considered in extrapolating performance to other reservoirs.

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STRATIGRAPHIC GEOPHYSICS— A TOOL FOR THE FUTURE

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ABSTRACT

The technologies of geophysicists and geologists now have more in common due to advances in seismic acquisition, processing, and interpretation of record sections. In the past, seismic data was used only for structural interpretation, but now it is used to interpret paleoenvironment, lithologic variations within intervals, reservoir thickness and areal extent, fluid contact, and other geologically important features.

To illustrate several new advances, modeling examples of seismic response in differing geologic settings are shown and the advantages of wavelet-processed or zero-phase sections are discussed. A method of converting well-bore data and seismic traces to a similar basis for comparison will be discussed, and an actual case study will be shown.

INTRODUCTION

Seismic interpretation has heretofore been principally restricted to identifying the structural nature of the subsurface. However, in the last few years the data has been used for identification of a stratigraphic unit and lithologic changes within that unit. For example, Figure 1 is a synthetic seismic section derived from a commonly encountered geologic cross section. It cannot be easily interpreted, but after specialized processing (Fig. 2) the seismic section can be interpreted as shoreline sands en echelon (Fig. 3).

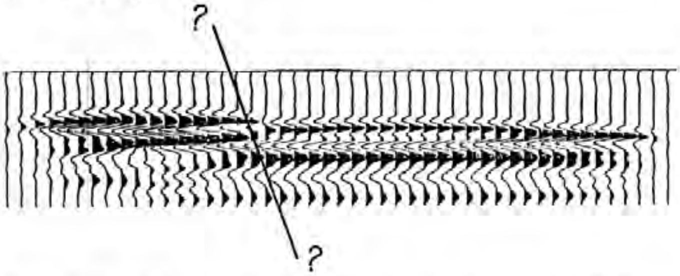

Figure 1. Synthetic seismic section showing en echelon sands. Without special processing, the section cannot be easily interpreted.

The AIMS™ Modeling System is used to generate synthetic seismic data and to study the validity of its interpretation. This system converts a geologic cross section into a seismic time section. For instance, the seismic

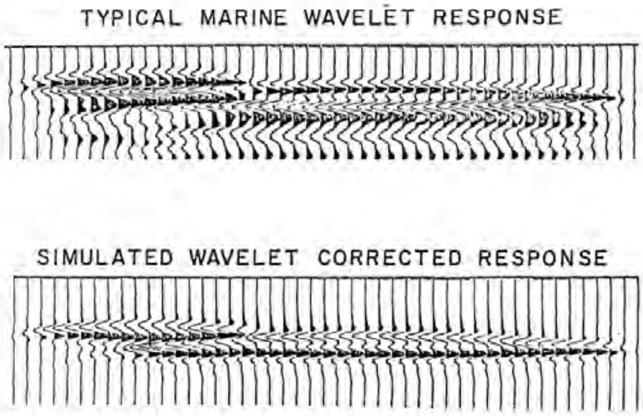

Figure 2. Corrected marine wavelet response indicating shoreline sands.

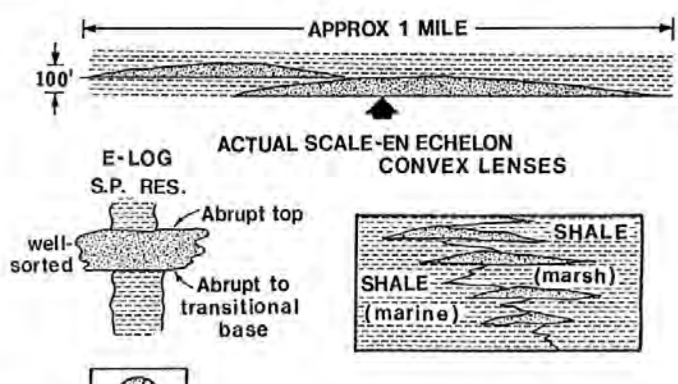

Figure 3. Synthetic seismic section with special processing can be interpreted as shoreline sands en echelon.

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section in Figure 4 corresponds to the geologic section in Figure 5, and an AIMS synthetic section (Fig. 6) confirms that interpretation. This system has been used throughout this paper to generate examples.

In order to interpret the seismic section easily and more properly, the data must first be wavelet processed.

GENERAL SEISMIC PROCESS

Figure 7 is a schematic representation of the seismic process. In the center of the figure is a seismic trace which is the result of seismic data collected over the subsurface, which is depicted on the left of the figure. In

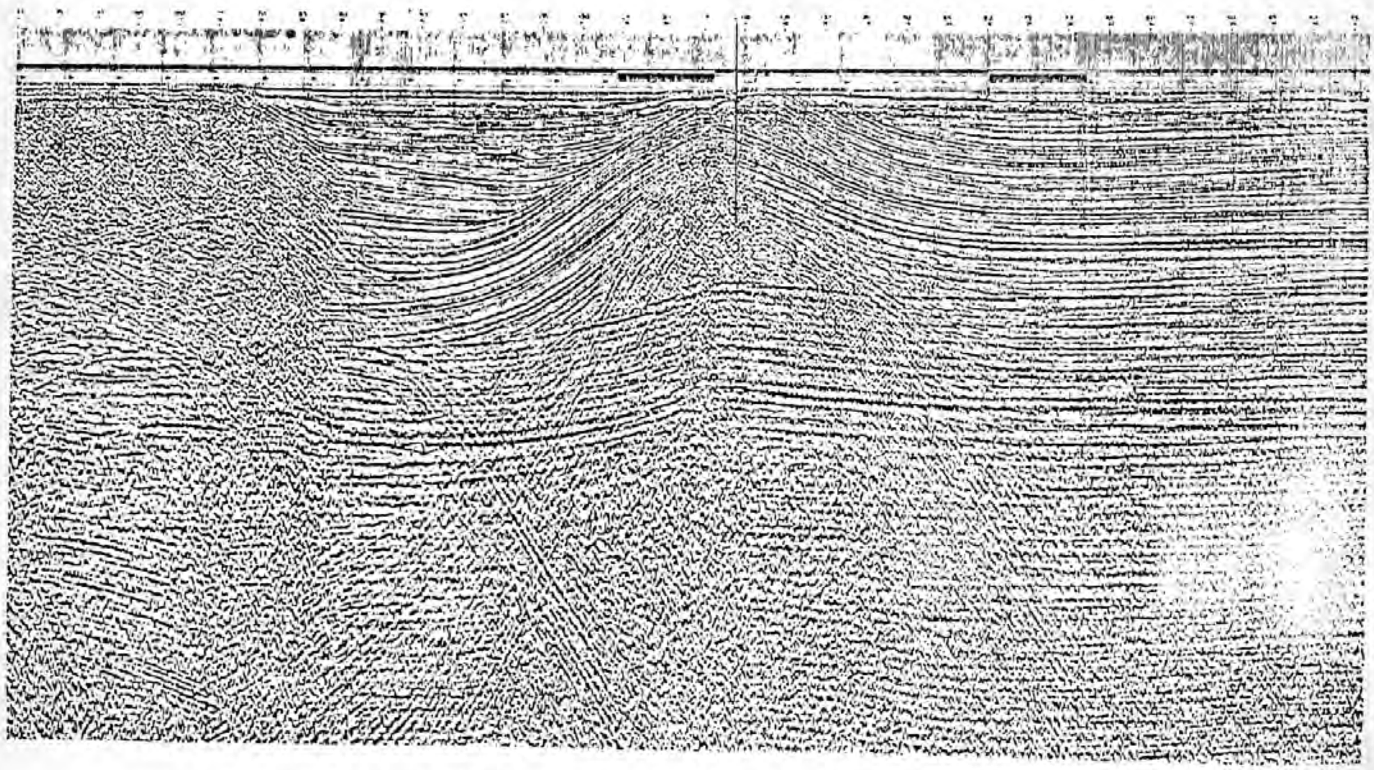


Figure 4. Seismic section, 48-fold CDP, corresponds to cross section in Figure 5.

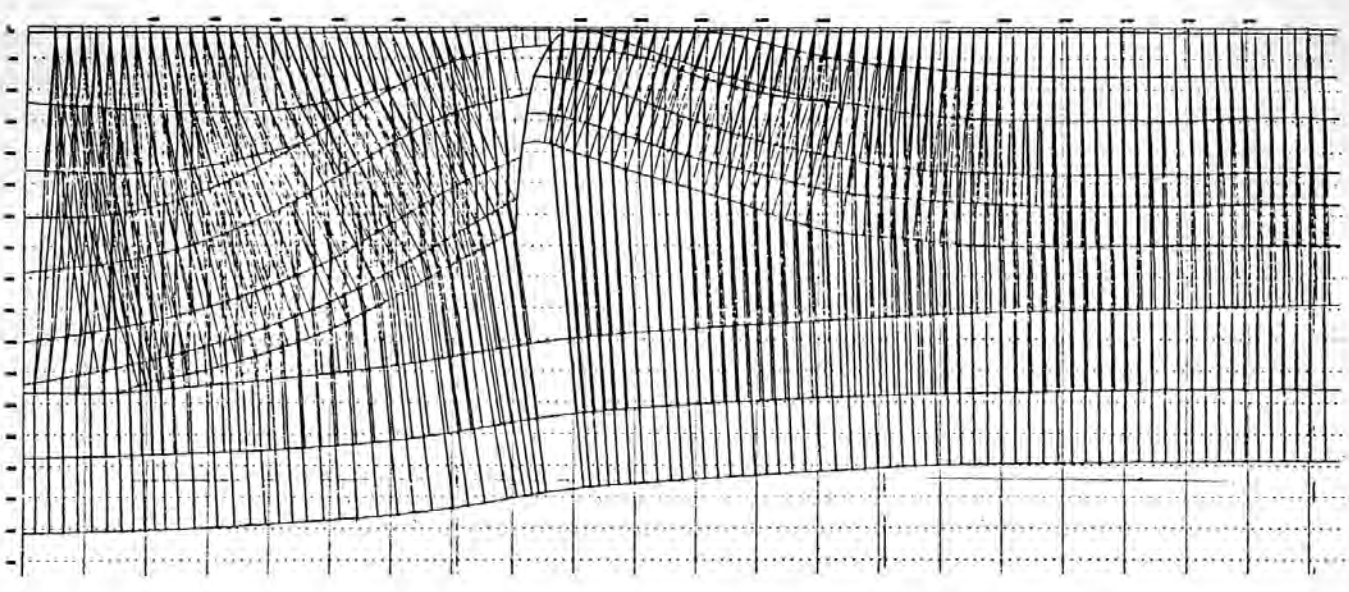


Figure 5. Cross section corresponds to seismic section in Figure 4.

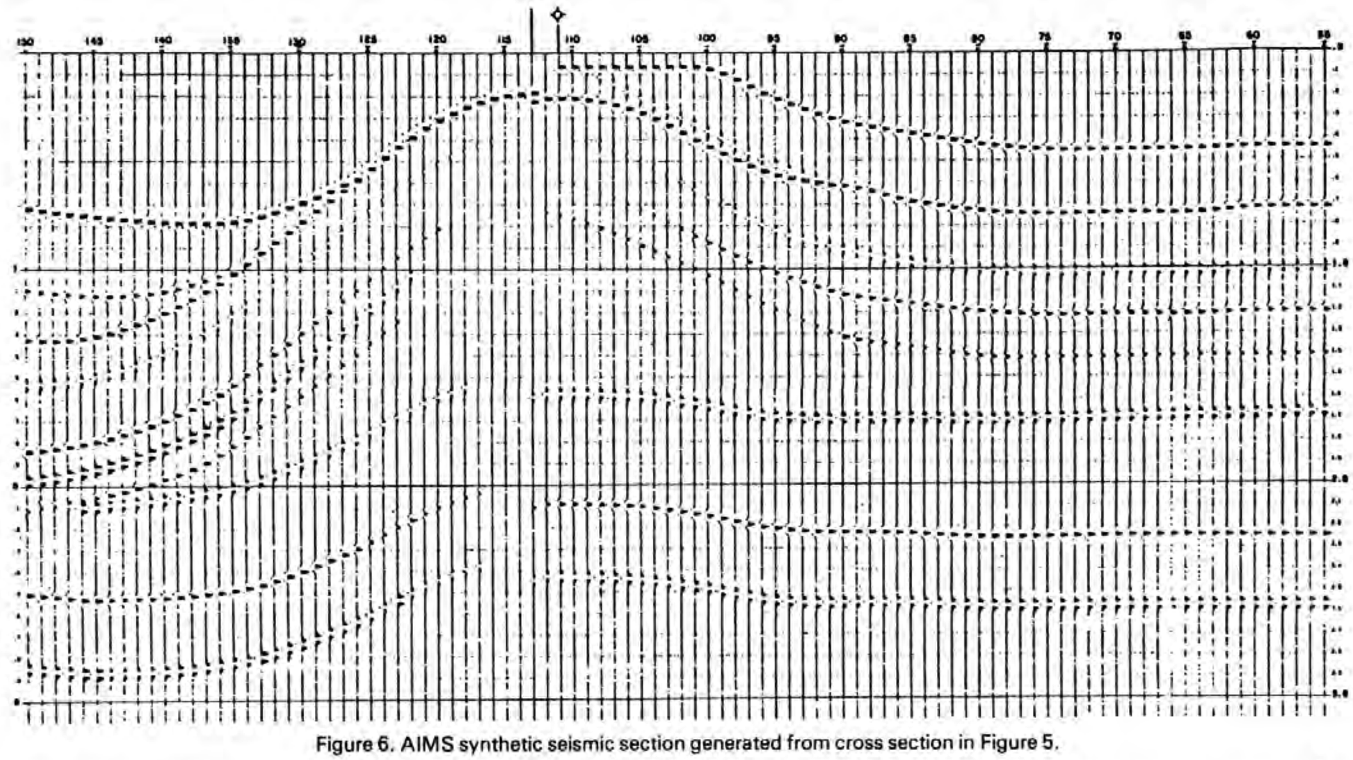


Figure 6. AIMS synthetic seismic section generated from cross section in Figure 5.

terms of simple communications theory, the seismic trace is the result of the convolution of the earth reflection series with a propagating wavelet. Each reflector on the reflectivity series is the result of a change in acoustic impedance (acoustic impedance is the velocity-density product of the rocks); therefore, a reflection often indicates a change in lithology. However, any mechanism which changes the velocity-density product will produce a reflection.

The geophysicist is presented with a set of seismic traces and it is his job to unravel them and determine which deflections represent changes in acoustic impedance or reflectors. In recent years, there has been an ever-increasing demand to correlate seismic events data with lithologic interfaces, and to measure physical properties of the strata in the subsurface using seismic data. Amplitude has been one of the key indicators to measure acoustic impedance, and if a relationship between velocity and density can be deduced for the area of interest (Gardner, 1974), then amplitude can be used to measure velocity or density.

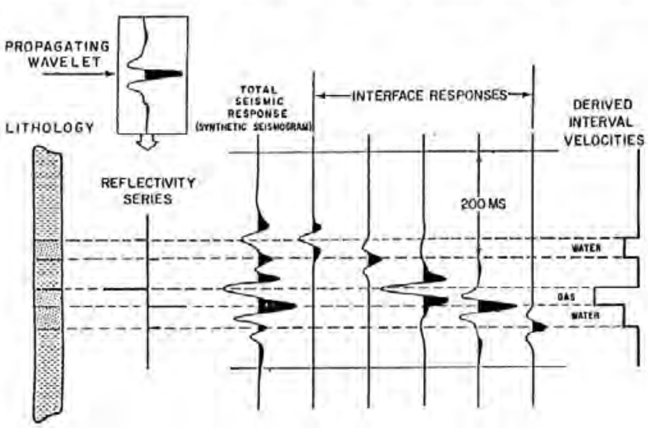
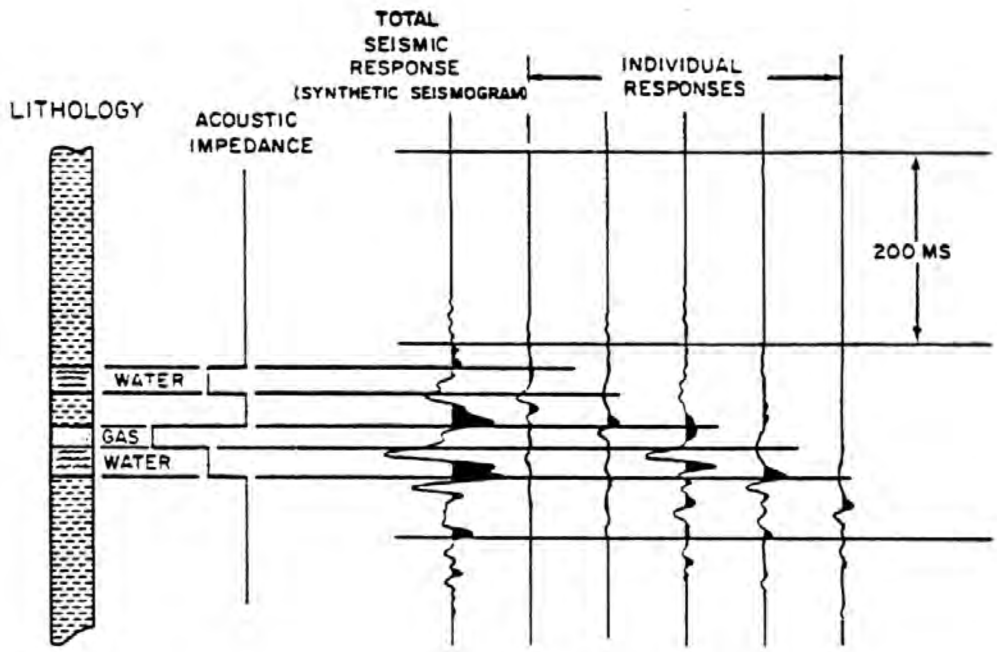


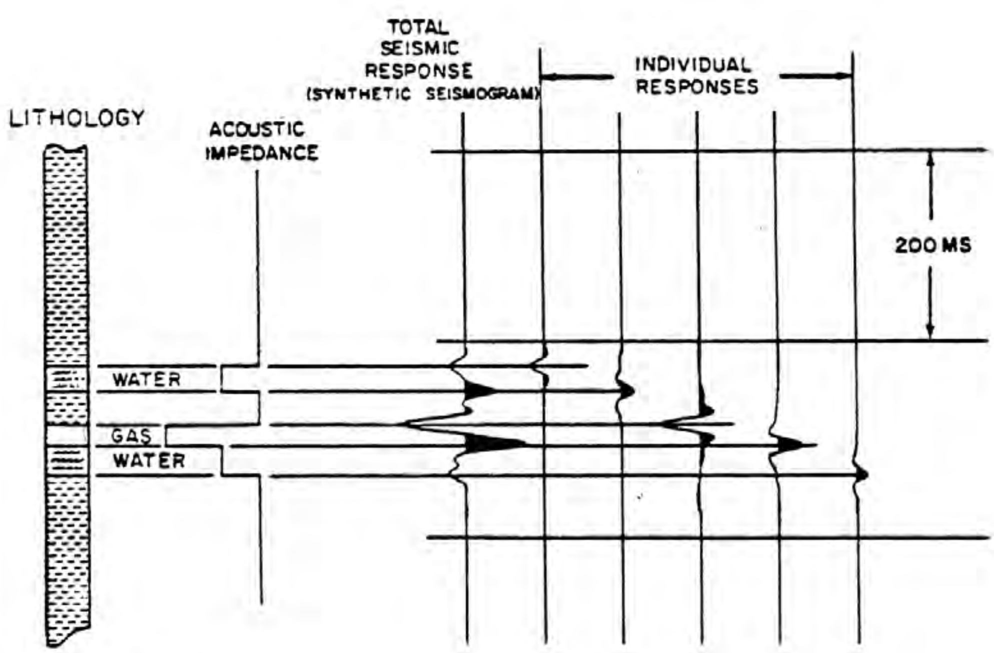
Figure 7. Schematic representation of seismic process.

The propagating wavelet has a simple, symmetrical shape; this simple shape has made unraveling the seismic trace relatively easy. The upper part of Figure 8 shows a lithologic column, a reflectivity series, and a seismic trace similar to the one in Figure 7. The seismic trace is the result of convolving the reflectivity series and a typical marine wavelet from real seismic data. The shape of this wavelet is a result of source signature, ghosting effects, instrument and cable response effects, and earth effects. It would be desirable to be able to change the shape of the propagating wavelet in the seismic data from the long, complex shape of a basic wavelet to the symmetrical, desired wavelet shape. This can be done in the processing center and the technique is called ''wavelet processing.''

Figure 8 also shows the desired wavelet, or the shape to which we would like to convert the basic wavelet in



(A)



(B)

Figure 8. Relationship between lithology and seismic response. (A) Marine airgun wavelet. (B) Zero phase band pass wavelet.

the data. The desired wavelet is zero phase and, by design, has the same bandwidth as the basic wavelet. In addition, the result of the convolution of the operator with the basic wavelet is predictable and it closely approximates the desired wavelet.

Wavelets produced by most marine sources have a complex shape and a time duration on the order of 200 milliseconds (Fig. 9). These wavelets generally exhibit a mixed-phase frequency behavior; the amplitude spectrum often resembles a roller coaster. Because of the poor behavior and excessive length of the propagating wavelet, the seismic response of even relatively simple stratigraphic sequences is very complex. Frequently, the superposition of wavelets from closely spaced reflectors forms patterns on the seismic section that could be interpreted as stratigraphic features. Minimum-phase deconvolution is usually of little help in alleviating the problem of poor resolution and false stratigraphy. This is because the deconvolution operator designed from the autocorrelation function is only correct for a minimum-phase wavelet. The effectiveness of conventional deconvolution in shaping a wavelet into a band-limited spike decreases as the wavelet departs from minimum phase.

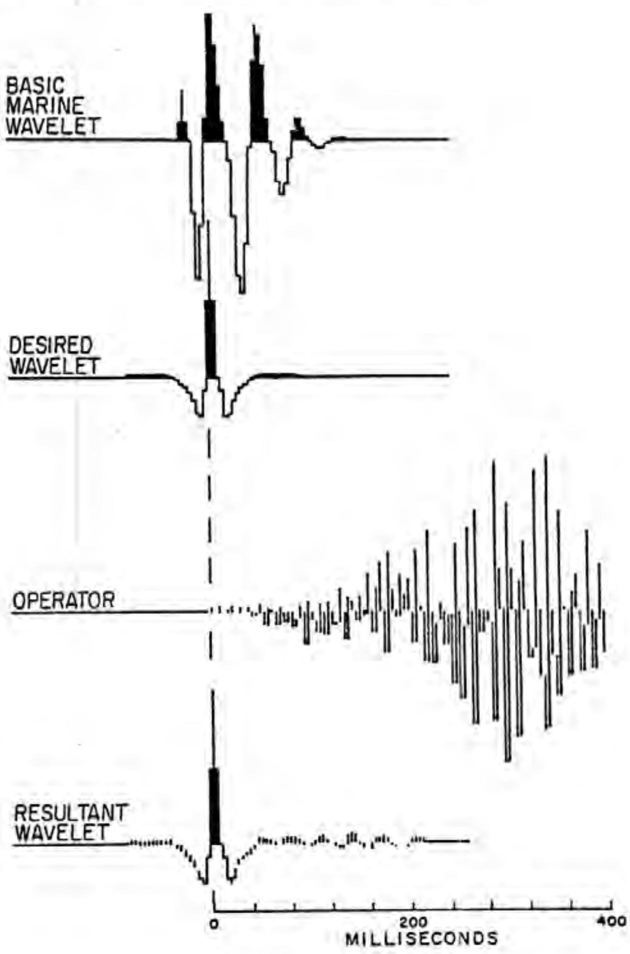


Figure 9. Shape and time duration of wavelets produced by marine sources.

To investigate the effects of deconvolution on primary reflections, a synthetic seismic section was calculated from the depth model of the horst-fault block shown in Figure 10. The synthetic time section shown in Figure 11 is the wave-theory spike section of the horst-block depth section, with added noise. The resultant time response contains all primaries and diffractions, but no multiples. Multiples were excluded since the purpose of the test is to show the effect of conventional deconvolution on waveforms rather than its effectiveness in attenuating time-stationary multiples. The spike section in Figure 11 was convolved with two types of basic marine wavelets and a zero-phase wavelet that had approximately the same width as the two previous wavelets (see Figs. 12, 13, and 14). Each of these sets of data were deconvolved using a 200-millisecond operator with a 50-millisecond prediction distance. A further comparison of the deconvolved sections (Figs. 15, 16, and 17) indicates the degree of complexity introduced by the basic wavelets. Contrastly, the zero-phase wavelet shape shown in Figure 17 was not altered; thus, the primaries are essentially unaffected by the predictive deconvolution. On the other hand, both the air-gun (Fig. 15) and the sleeve-exploder (Fig. 16) examples show that the closely spaced acoustic interfaces still cannot be resolved because of the complex nature of the basic wavelet. A direct result of deconvolution is the apparent inversion of dip below 3.3 seconds (Fig. 16). This is a result of the wave-shaping action of the deconvolution on the reflected data. In contrast, zero-phase section events (Fig. 17) are well defined and no ambiguities are introduced by deconvolution. The two-way time down to each reflector can be measured exactly at the point of symmetry of the wavelet, while in the two previous examples, the correct time should be read at the onset of the wavelet. The onset in the latter case is seldom visible because of its low amplitude; consequently, a delay is introduced by picking a later cycle in the wavelet.

In most detailed seismic applications it is necessary to calibrate seismic information with wellbore data. Conse-

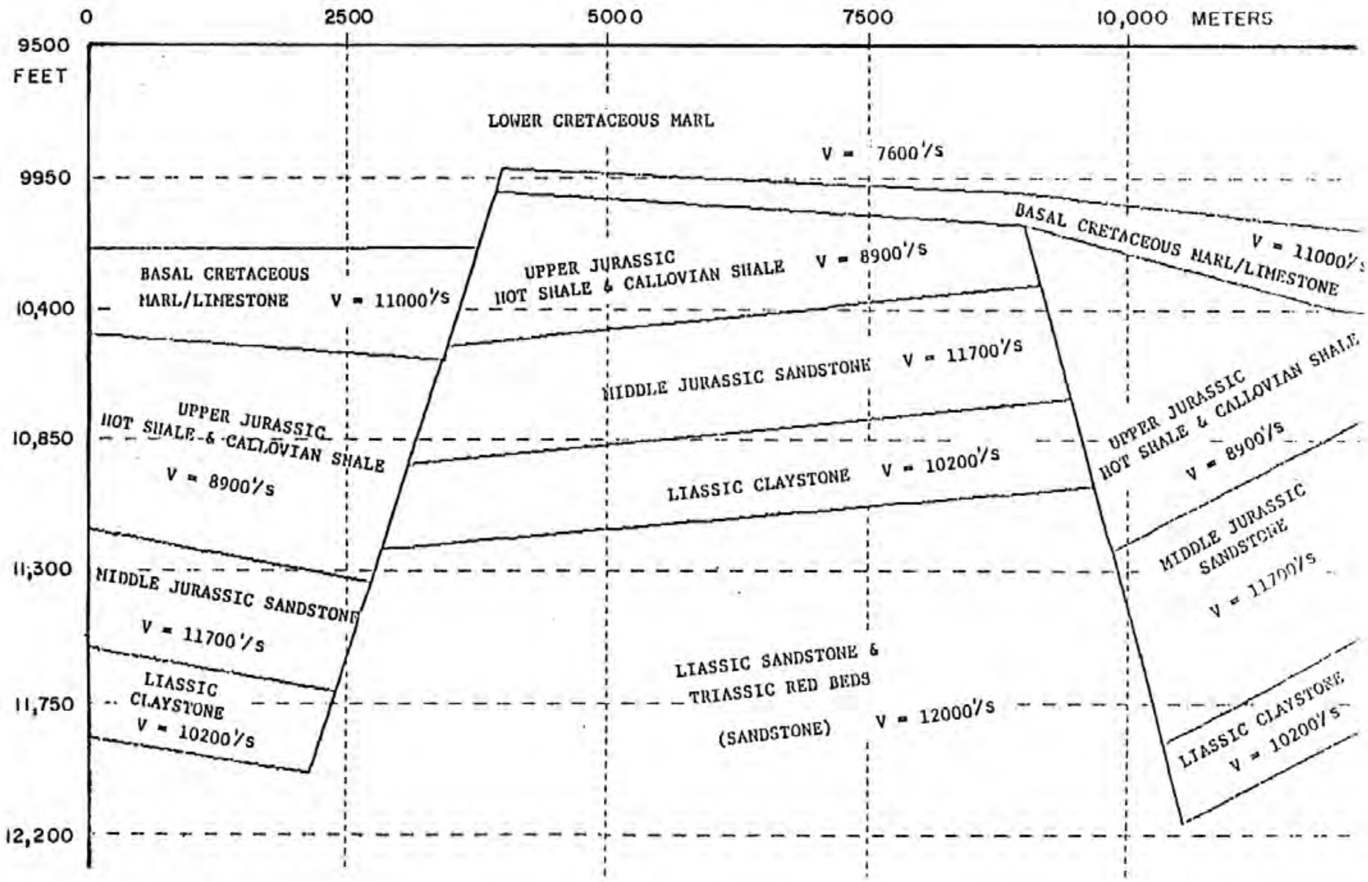


Figure 10. Depth model of North Sea horst fault block.

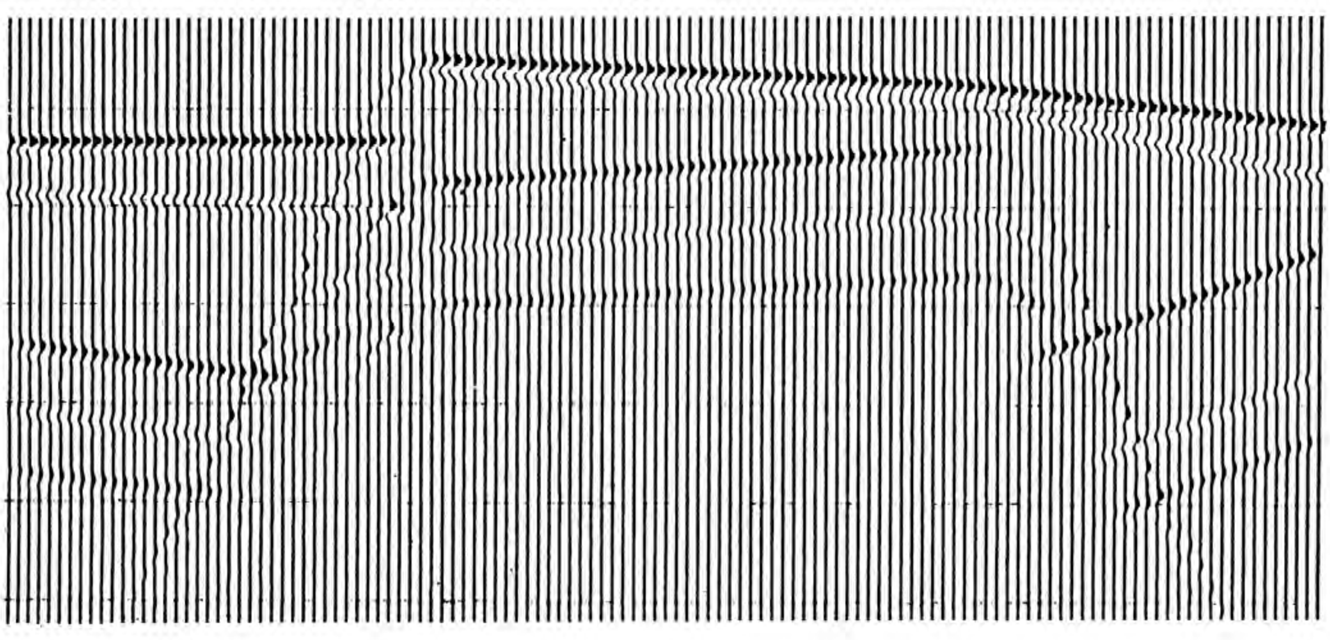


Figure 11. Synthetic time section of Figure 10 showing wave-theory spike section with added noise.

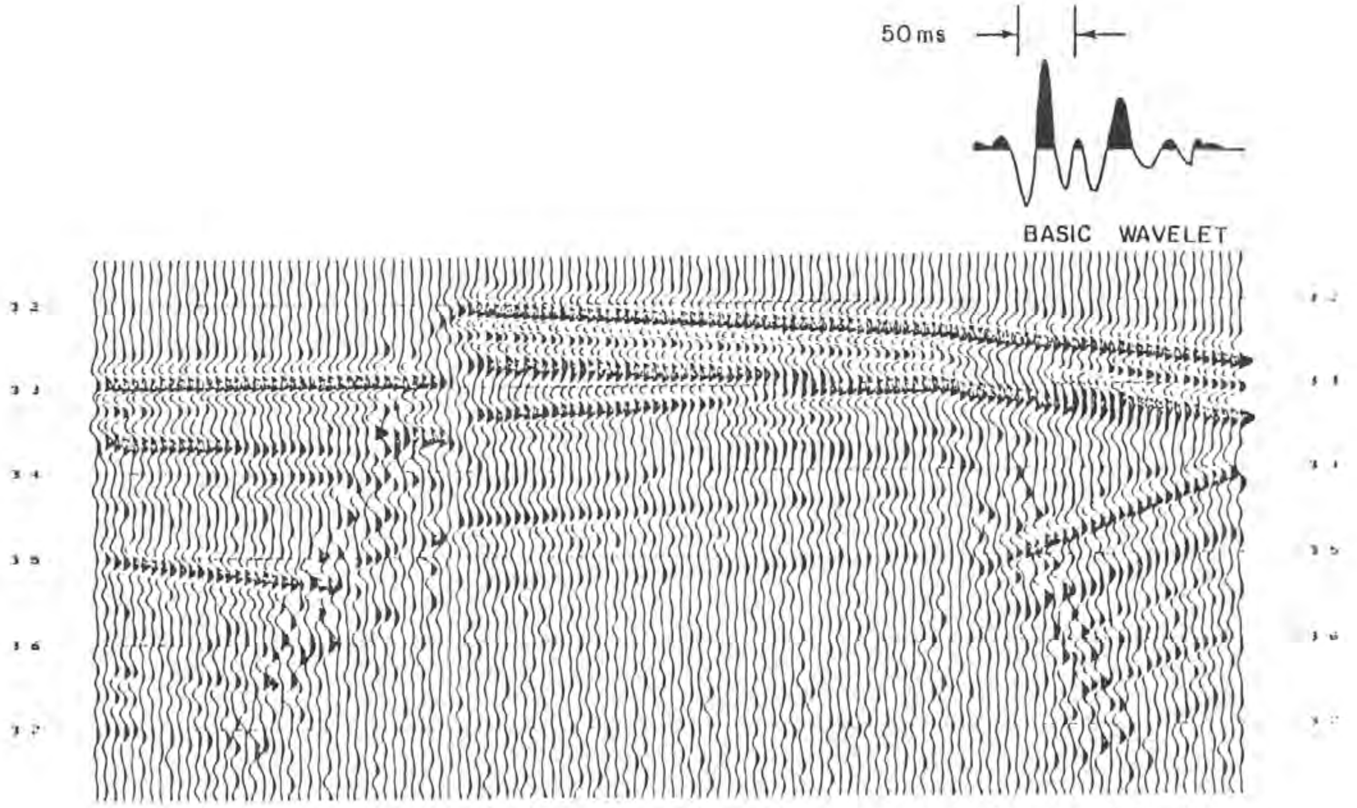


Figure 12. Convolution with two types of basic marine wavelets and a zero-phase wavelet of spike section in Figure 11.

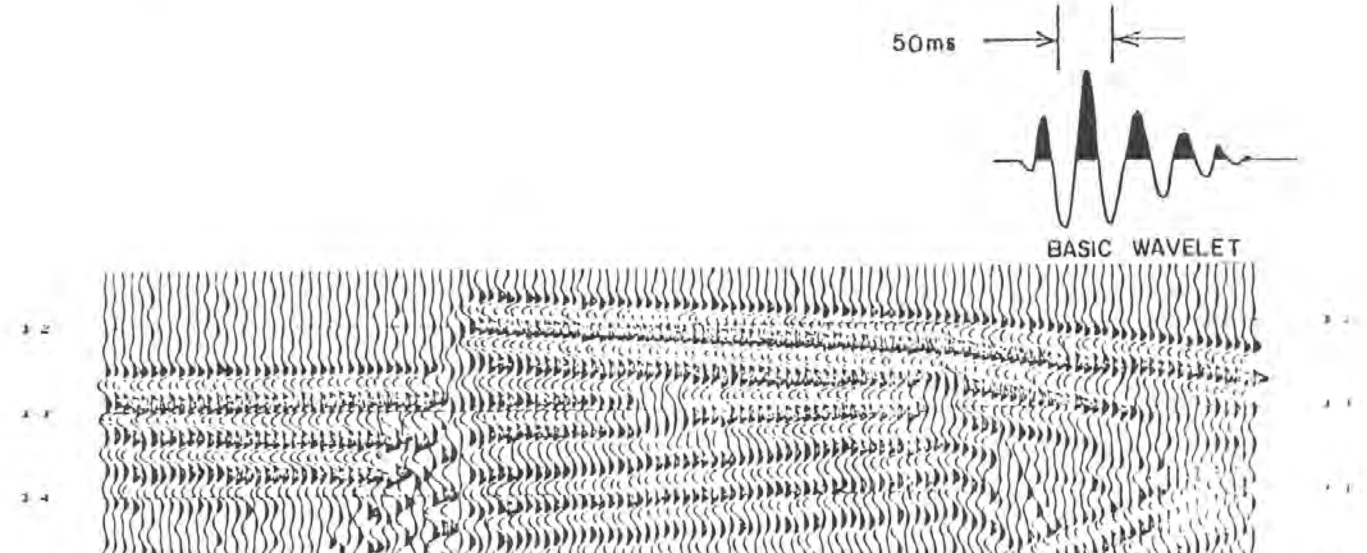


Figure 13. Convolution of North Sea wavelet with approximately the same width as the wavelet in Figure 11.

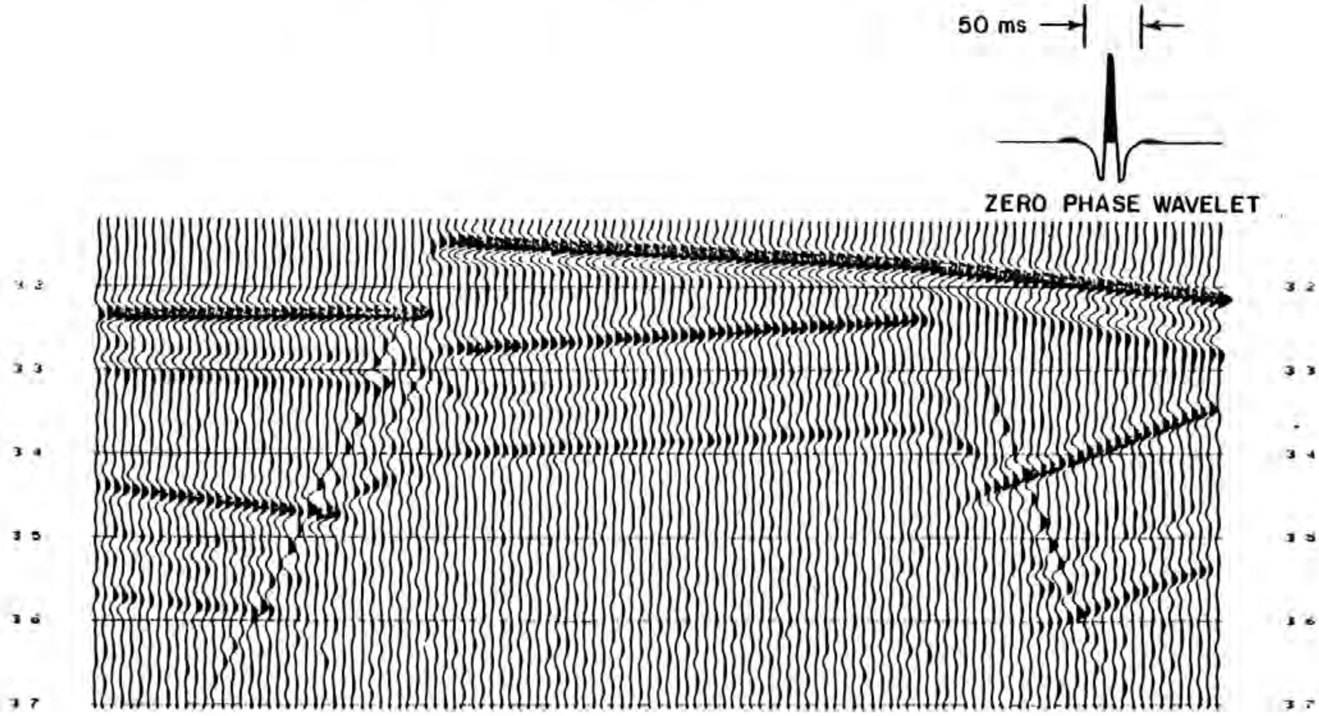


Figure 14. Convolution of North Sea wavelet with approximately the same width as the wavelet in Figure 11.

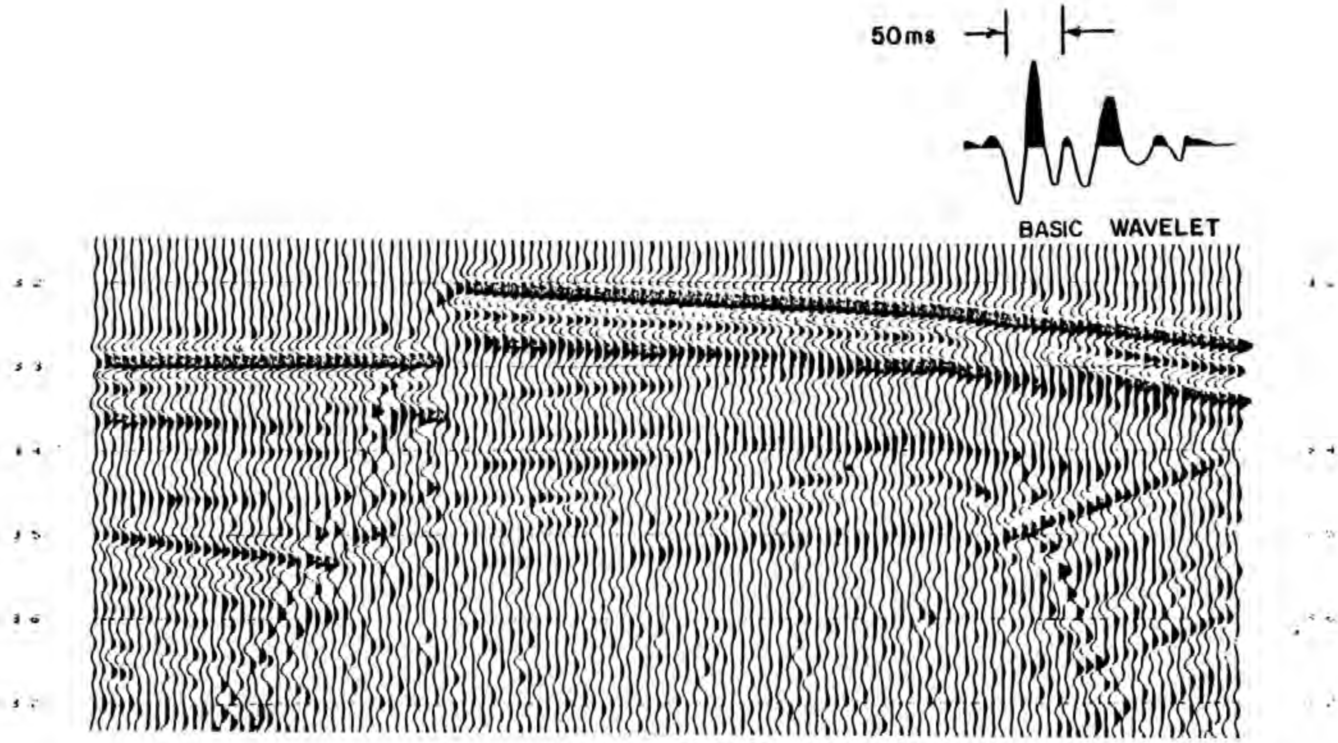


Figure 15. Deconvolution of basic wavelet in Figure 12.

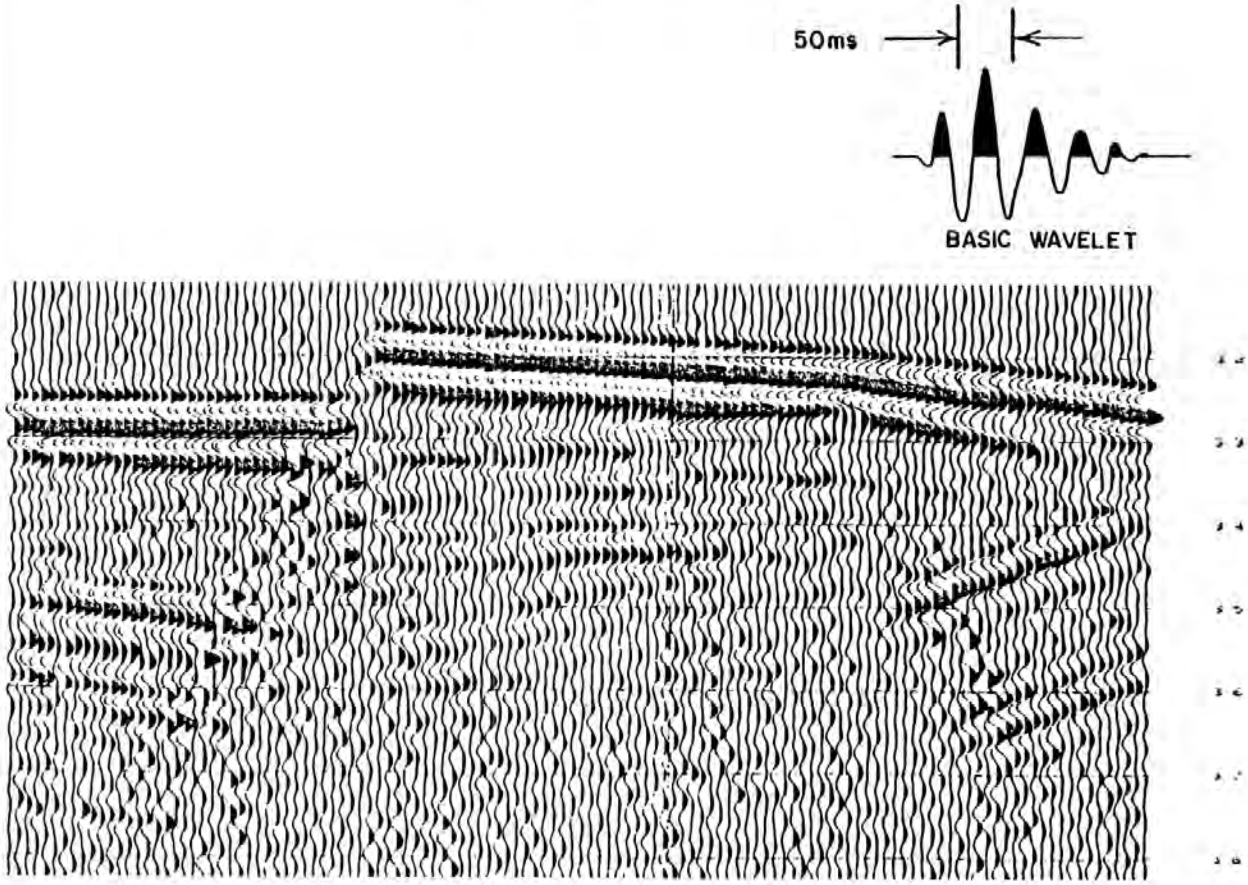


Figure 16. Deconvolution of basic wavelet in Figure 13.

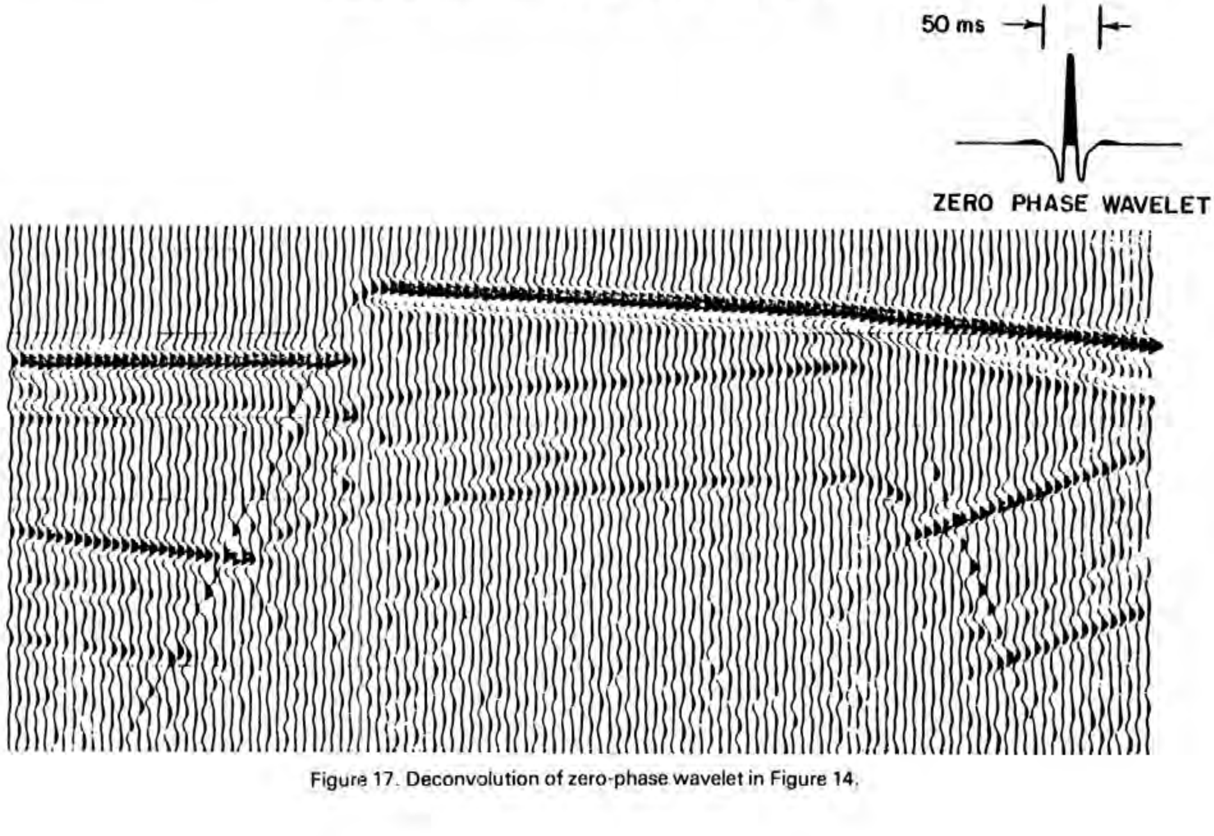


Figure 17. Deconvolution of zero-phase wavelet in Figure 14.

quently, every effort must be made to insure that wellbore data provides the best possible presentation of in-situ physical properties of the subsurface section.

Several things must be done to reduce well-log and seismic data to a valid comparison level; these include time-depth reconciliation, filtering to account for different frequency contents, and integrating so that intervals can be compared to intervals and not interfaces. However, befor using well-log data for geophysical control, the log must be edited.

It is not uncommon for portions of a well log to contain data that are significantly different from the true, in-situ formation properties. This may be due to log calibration problems or environmental conditions. Errors are sometimes included in well-log measurements, however. When geologists and geophysicists began to use well logs to construct synthetic seismograms, well logs were often digitized from ''top to bottom'' in a completely raw, unedited mode. No wonder the tie from wellbore to seismic data was often difficult. Still, it was generally accepted that some gross log editing was required to correct, for example, obvious hole washouts. Of course, log analysts have always paid careful attention to the quality of log values through pay zones. However, it was not until the advent of the ''bright spot (seismic amplitude analysis) technology,'' or, more recently, stratigraphic geophysics (reservoir continuity), that ''fine-line'' editing has been practiced.

Almost all formations are altered when a borehole is drilled through them. The more competent formations show an imperceptible change, while the softer formations often suffer significant, obvious alterations. Shales are altered by exposure to mud filtrate; they cave, erode, absorb water, and swell. The degree of weathering is a function of shale type and properties of the mud such as water loss, filtrate salinity, and weight. Other important factors are exposure time and other mechanical factors involved in drilling a hole. Sandstones are altered by relaxation (a function of mud weight) and erosion (a function of mud weight, water loss characteristics, and bit hydraulics).

Log editing is often interpretive. Consequently, one runs the risk of editing out valid data; but the risk is usually worthwhile to avoid including invalid information that may cloud the whole picture. Figure 18 is a severe, but plausible, simulated editing situation. A brief discussion of some of the editing follows.

INTERVAL 3000-5520

This interval is a sand-shale sequence in which most of the shales have been washed out, but in which many of the sands have not. The combination of hole enlargement and shale alteration can result in apparent shale velocities and densities being markedly less than those judged to be appropriate for the section.

The judgment is often based on trend curves developed from other wells in the area in which the hole conditions for the equivalent stratigraphic section were much better. In this simulated example, the correction trend is substantiated by observed shale velocity values in sections where the hole has not washed out (4960-5220 and 5370-5520). Perhaps 4960-5220 has not washed out because it was logged relatively soon after it was drilled, and, therefore, had less exposure time. Perhaps 5370-5520 has not washed out because the mud quality was improved and was more easily maintained after the casing string was set at 5220.

The shale interval below the casing shoe, 5520-5370, has washed out. Possibly, the mud quality was not good immediately upon drilling out of casing but by the time the drill bit reached 5370 mud properties had stabilized, resulting in less hole enlargement. In addition, mud circulation hydraulics (annular turbulence) can sometimes cause washouts beneath casing shoes. If a mechanical reason for a hole washout can be determined, values from nearby equivalent zones can be sub-

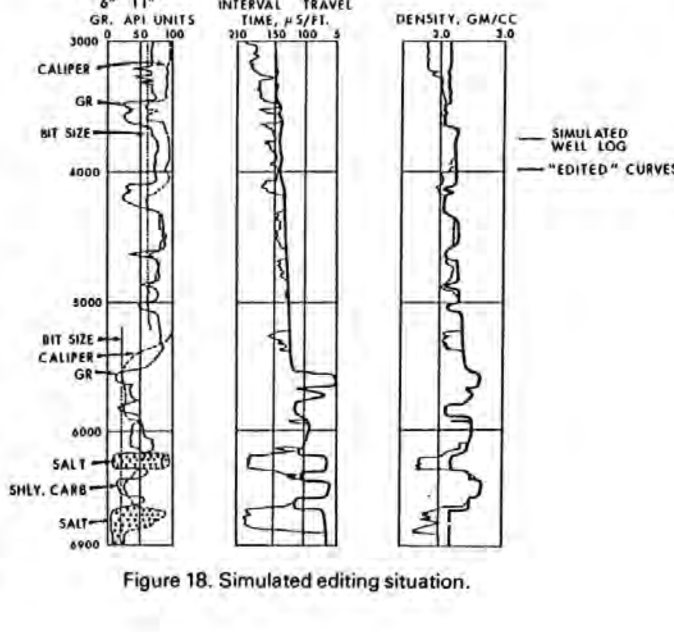


Figure 18. Simulated editing situation.

stituted. However, if no mechanical reason can be identified as the cause of hole washout, the substitution value should be carefully considered. Perhaps the zone washed out because it was different from nearby equivalent zones.

The density log has to be edited for many of the same reasons. Shale alteration and washouts affect the density log, too. Hole washouts, as they pertain to density-log readings, can be subdivided into rugosity and enlargement. Rugosity, or roughness, sufficient to cause density-log errors (lack of pad contact) can sometimes occur with relatively little hole enlargement. Significant hole enlargement results in a different mechanical conformation of logging tool pad to borehole wall than that used when the standard bulk density-count rate relationship was developed.

INTERVAL 5520-6900

This interval is a mixed section of limestone, sandstone, shale, and salt. With the exception of a few obvious hole washouts noted on the caliper in shale sections, most of the editing of this lower section is related

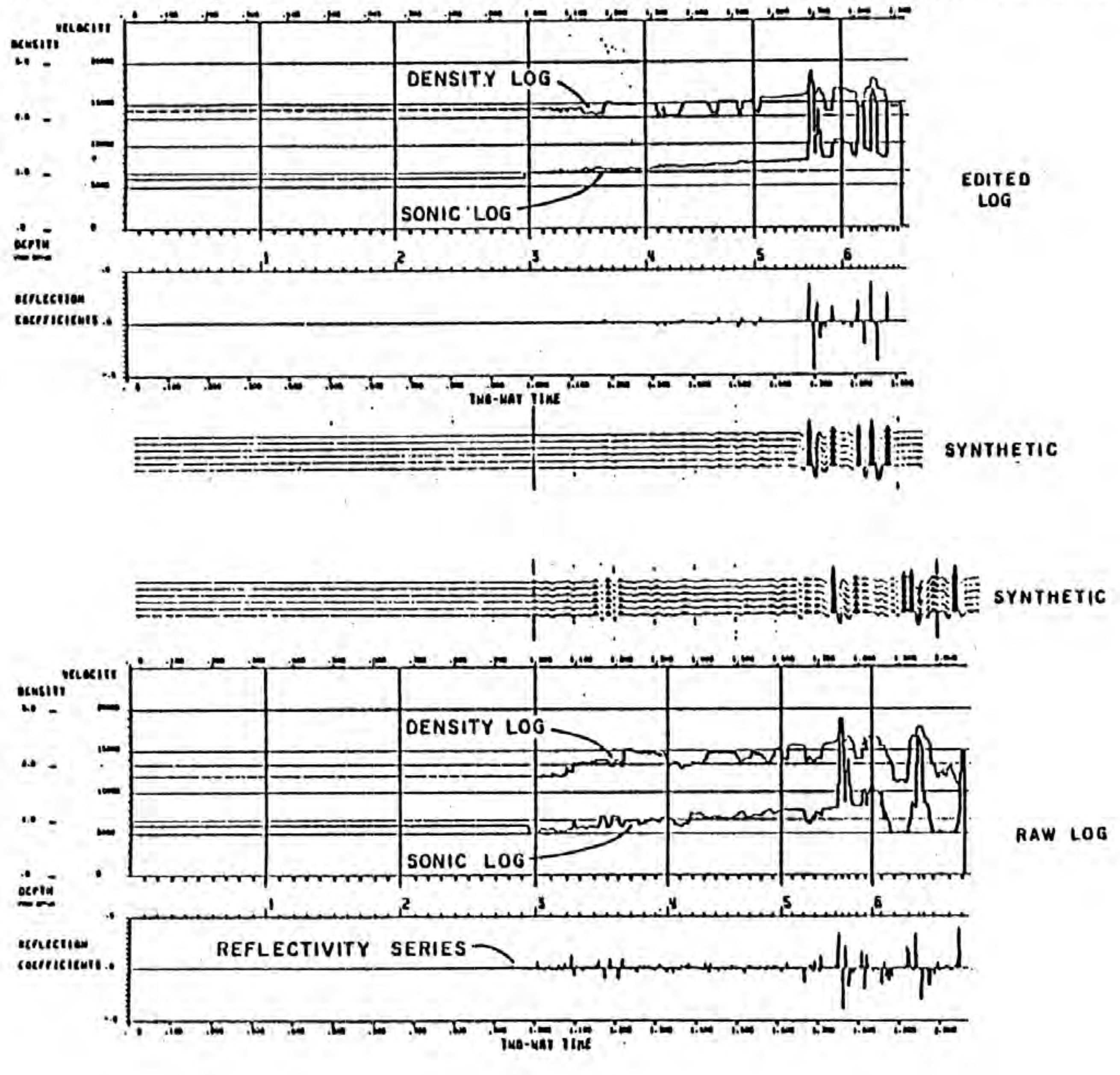


Figure 19. Comparison of synthetic seismogram from raw log data and synthetic seismogram from edited log data.

to the salt sections. Probably the salt layer, 6190-6300, is washed out completely. As a result, both the sonic and density logs are essentially recording the properties of borehole fluids, which are markedly different from salt parameters. The density log has been edited from 6790-6900, even though the hole is in guage throughout that section. Due to a different electron-bulk density relationship for salt than most other sedimentary rocks, the apparent density log bulk density of salt is not the true bulk density. Contrastly, the sonic response in the gauge salt section substantiates the validity of the sonic editing of the washed-out salts.

Figure 19 compares a synthetic seismogram obtained from raw log data and a synthetic seismogram obtained from edited log data. The differences are significant. In the shallow part of the section the synthetic seismogram from unedited data has much more character than the synthetic seismogram from the edited data. These ap-

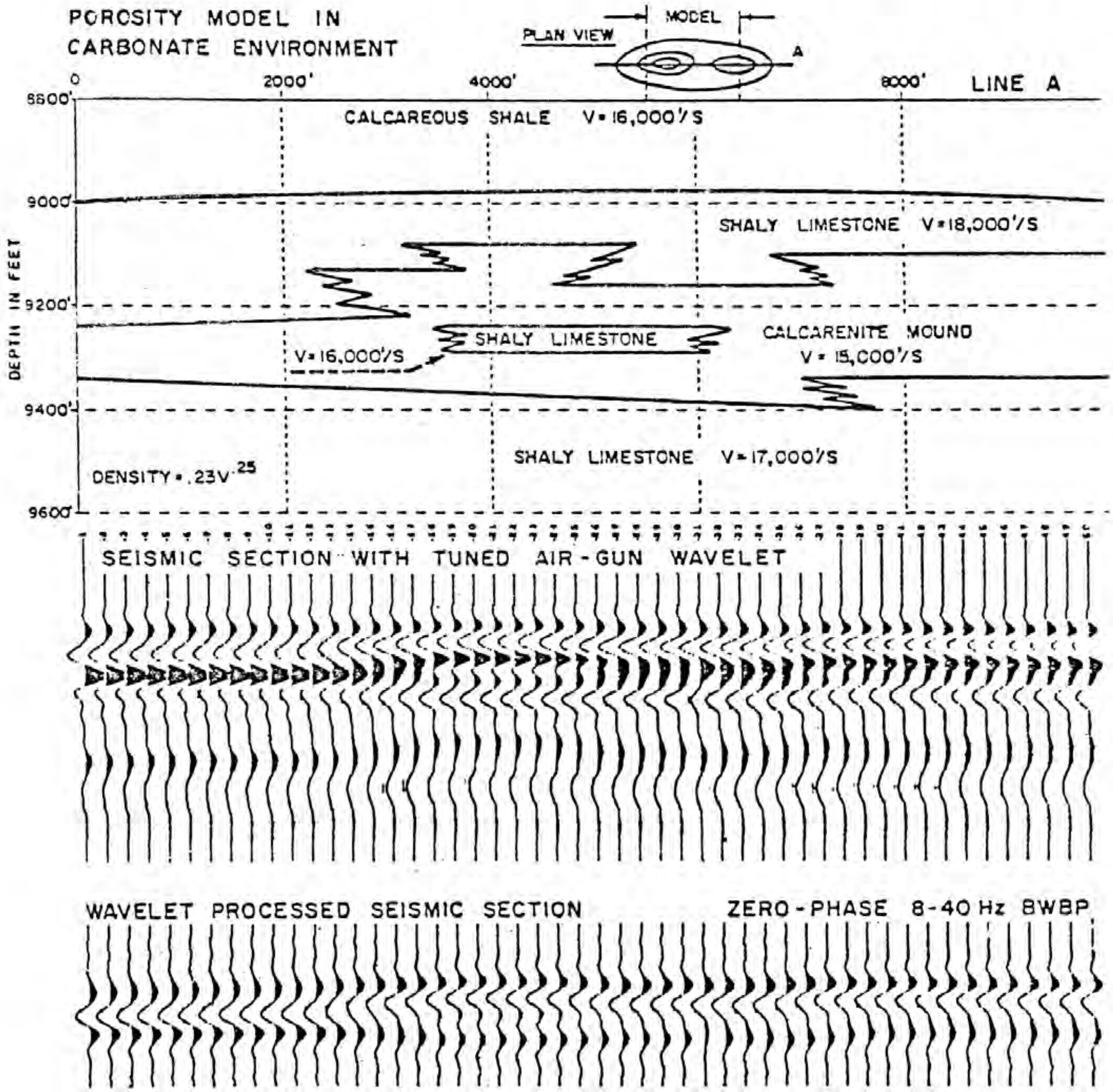


Figure 20. Porosity model of carbonate environment.

parent events represent only the observed contrasts in the erroneous information and not any real acoustic impedance contrast in the subsurface. Also, the last major event from the unedited set occurs at approximately 2.03 seconds, while on the edited version this event occurs at approximately 1.875 seconds. This difference reflects the significance of the up-hole velocity in achieving depth-time ties between seismic and wellbore data. In this case, the "too slow" velocity observed on the up-hole portion of the raw log could make a difference of 500 to 1,000 feet in the location of the last events. This example demonstrates that:

1. Bad data may have been recorded. This may be easily determined in the cases of obvious noise (for example, cycle skips) or hole washouts. This may not be easily determined in the cases of subtle changes in hole conditions, different lithologies, borehole weathering, or undetected or unrecorded log calibration problems.
2. Better values must be substituted for the bad values.

Calibration will be done at the level of acoustic impedance comparison. This involves filtering the log data and then integrating the seismic data to the SYN-LOG™ format.

CARBONATE MODEL

Figure 20 is a model of a carbonate environment in which a porous calcarenite mound with a shaly limestone inclusion is embedded in a shaly limestone; the environment has high potential as a reservoir. The model seismic response is shown for the case of conventional processing where the propagating wavelet is a tuned air-gun wavelet. Also shown are the results of wavelet processing of the data so that the propagating wavelet in the data is zero phase and symmetrical. Note the simplicity of the wavelet-processed seismic data compared to the conventionally processed data. This difference is due solely to the wavelet shape, because the same reflectivity series was used in both cases.

Figure 21 shows the SYN-LOGS for each of the two seismic sections. The SYN-LOG analysis of the wavelet-processed data produced a close approximation of the actual subsurface (Fig. 22). The definition of the lower velocity calcarenite potential reservoir and the shaly

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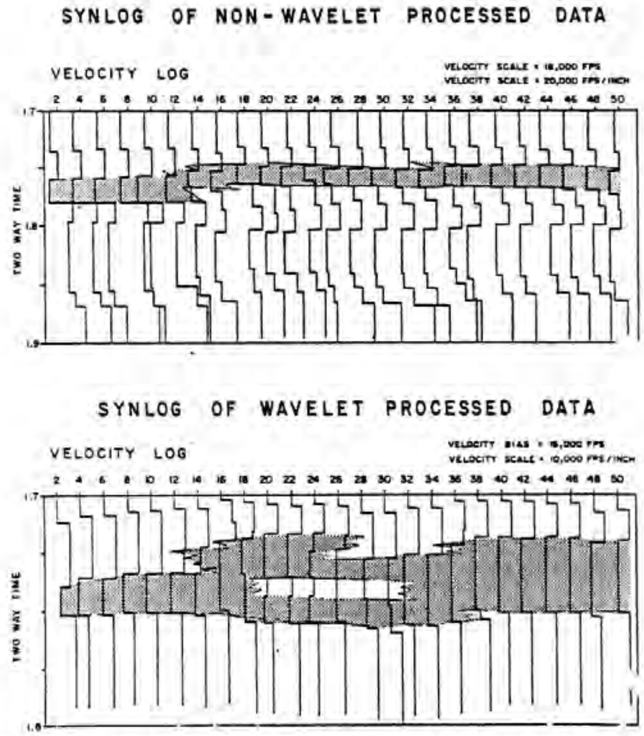

Figure 21. SYN-LOG of non-wavelet processed data and SYN-LOG of wavelet processed data.

Figure 22. Approximation of subsurface developed from seismic data.

limestone inclusion can easily be seen. These results contrast with the SYN-LOG run on the conventionally processed data. SYN-LOG indicates that the potential reservoir is thinner than it actually is. It portrays a more complex lithology below the calcarenite than actually exists. This analysis also shows velocity changes at about 1.85 seconds, which are not in the model, and, once again, false lithology is implied. These poor results are because the wavelet in the data is not zero phase and, for the purpose of the exercise, is unknown. Even though the reflector times were picked to minimize the differences between the seismic trace and the SYN-LOG model response, the results are poor. In order for the SYN-LOG technique to be effective, the data must be wavelet processed so that the wavelet in the data is known and zero phase.

NORTH SEA LINE 1

A portion of a line of seismic data from the North Sea was analyzed to show how the technique described can be used to integrate seismic and well-log information, and to show the interpretive potential of the SYN-LOG method. Figure 23 is a section of seismic data from the North Sea that has been wavelet processed. A well has been drilled and logged at SP 230 and shows an oil sand associated with the reflection series seen at approximately 2.9 seconds.

The first seismic trace analyzed by SYN-LOG was the one at SP 230, since it tied the well. A velocity-density relationship was determined using the well data from the zone of interest; the velocity trend was also derived from the sonic log. Figure 24 shows the sonic log;

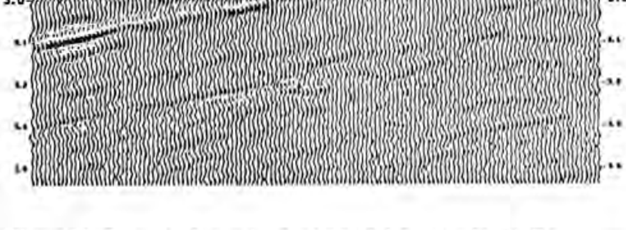

Figure 23. Section of wavelet-processed data from North Sea.

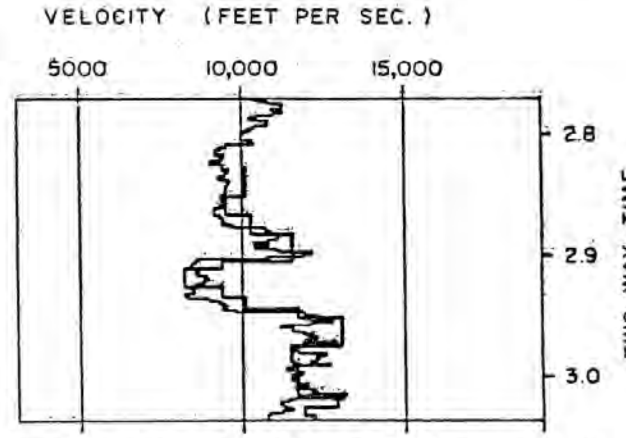

Figure 24. Sonic log of Figure 23 with SYN-LOG analysis of portion of the trace at SP 230 overlaid.

the SYN-LOG analysis of a portion of the trace at SP 230 is overlaid. The SYN-LOG results match the shape of the sonic log; however, the high-frequency detail is not present. This is to be expected because of the limited bandwidth of the seismic data. The SYN-LOG technique is capable of generating a synthetic sonic log from seismic data which, considering the bandwidth of the seismic data, bears a close resemblance to the actual sonic log.

Starting with SP 230, a window of data from the trace at SP 225 was analyzed in order to bracket the well, and then selected traces down the line were analyzed. These results are shown in Figure 25. The lighter plot for each synthetic log represents only the inverse model information and the dark plot represents the sum of the inverse model results and the trend. This figure adds to the validity of the technique because of the lateral consistency of the synthetic logs. The lithologic log from the well shows that the low-velocity material at about 2.9 seconds (see Fig. 24) is the radioactive shale, and underlying it is an oil-filled sand.

The oil sand on each synthetic velocity log has been shaded in Figure 25. Above it is the low-velocity radioactive shale and below it on all of the logs except the one at SP 229 there appears to be an ordinary shale. The oil sand thickens downdip from SP 230 to SP 285. Also, in each case except SP 299, the interval below the oil sand is a slower velocity material; however, at SP 299 the interval below the oil sand is a higher velocity material, and the oil-sand thickness is decreased compared to the other logs. One possible explanation is that downdip the sand is watering out and SP 299 is a possi-

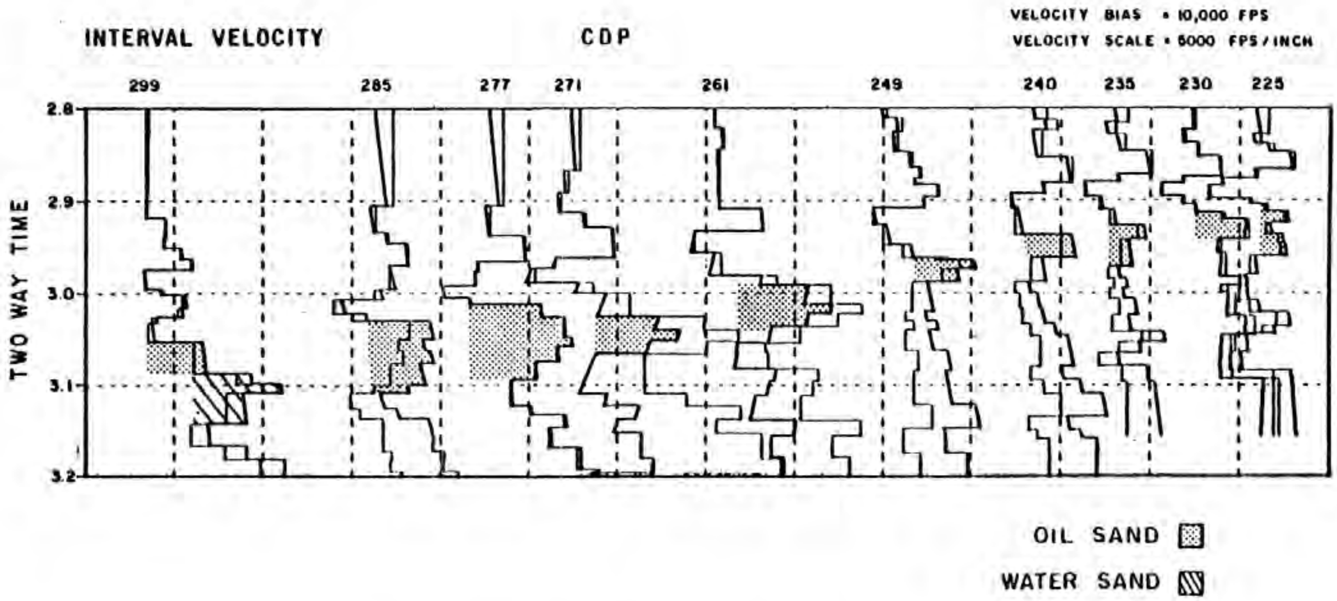

Figure 25. Results of data analyzed from window at trace at SP 225.

ble oil-water contact. A likely explanation for the relatively large velocity contrast between the oil sand and water sand is that mineralization and chemical action have taken place at the contact, causing an abnormally large velocity contrast.

In summary, a possible oil-water contact and the watering-out of the oil sand has been detected and the areal extent of a potential reservoir has begun to be defined. Neither of these phenomena are as evident on the seismic data as they are on the SYN-LOG section.

SYN-LOG is an inverse modeling technique which can reliably produce synthetic acoustic impedance logs from seismic data, and, if other information such as a relationship between velocity and density is available, sonic and density logs can also be produced. The concepts incorporated in the method are basic and uncomplicated, and if a well log from the area is available to calibrate this technique, reliable, quantitative results can be achieved. SYN-LOG is a block-impedance technique because it assumes that changes in impedance occur only at discrete interfaces. This requires that the geophysicist interpret, with some help from SYN-LOG, which deflections on the seismic trace are significant interfaces and which are the result of complex interference patterns or noise. This selection of interfaces is time consuming when sizeable amounts of data are analyzed. In order to alleviate this problem and relax the constraints of block impedance, another method has been developed and used with success.

INVERSE MODELING USING INTEGRATION

Since the wavelet in the wavelet-processed seismic data is zero phase and symmetrical, the traces can be treated as a band-limited relative reflectivity series. Using this assumption, an integration technique which produces a relative acoustic impedance log for each seismic trace has been developed. The technique is more fully automated because it does not require an interpreter to identify where the reflectors are located. It also makes the generation of SYN-LOG more automatic.

This technique was used on the data from the North Sea well. Figure 26 shows the reflectivity series, the integrated reflectivity series or acoustic impedance log, and the filtered acoustic impedance log. Since the bandwidth of the log information is significantly larger than the seismic data, the acoustic impedance log was filtered so that its bandwidth matched the bandwidth of the seismic data. The filtered acoustic impedance log shows the features that can be observed using seismic data with its limited bandwidth, and yields a better correlation when compared to the seismic data.

Figure 27 shows the synthetic seismogram derived

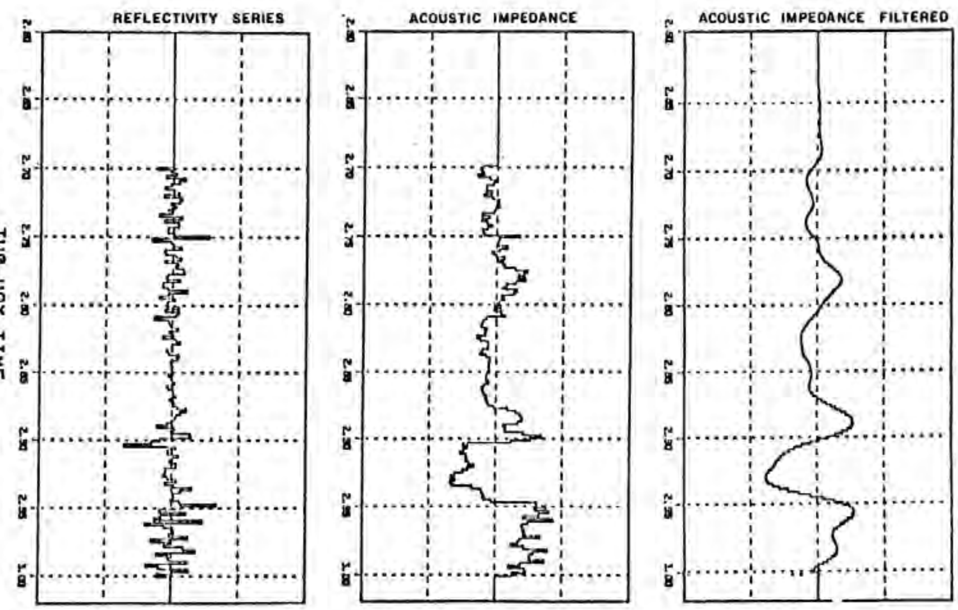

Figure 26. Reflectivity series, acoustic impedance log, and filtered acoustic impedance log of North Sea well.

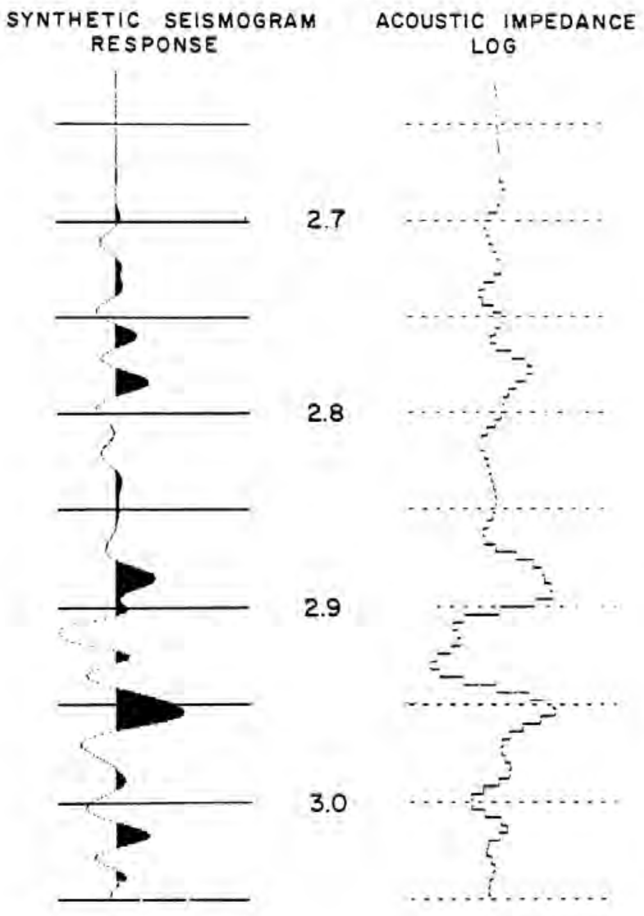

Figure 27. Synthetic seismogram response and acoustic impedance log from North Sea well logs.

from the North Sea well logs. This synthetic seismogram was treated as a seismic trace and integrated to produce an acoustic impedance log. The acoustic impedance logs in Figures 26 and 27 are very similar and show that the integration technique used to derive relative acoustic impedance from seismic data is valid.

One of the problems with this method is that it has been assumed that the wavelet-processed seismic trace is a band-limited reflectivity series, but the interference taking place because of the larger width of the symmetrical wavelet compared to a spike has not been accounted for. It is assumed that the interference effects are relatively small compared to reflection amplitudes on the seismic trace. Currently, methods to correct for this interference are being investigated. However, the above assumption appears valid.

The synthetic log from the seismic data at SP 230 was compared with the acoustic impedance log derived from well-log data (Fig. 26). Figure 28 shows the relative acoustic impedance log from SP 230, which was derived by integration. The general shape corresponds to the acoustic impedance log from the well; however, the seismic data does not have as high a frequency content as the synthetic log from the well. There is a good correlation, however, between the synthetic log (SYNLOG) and the filtered acoustic impedance log from the

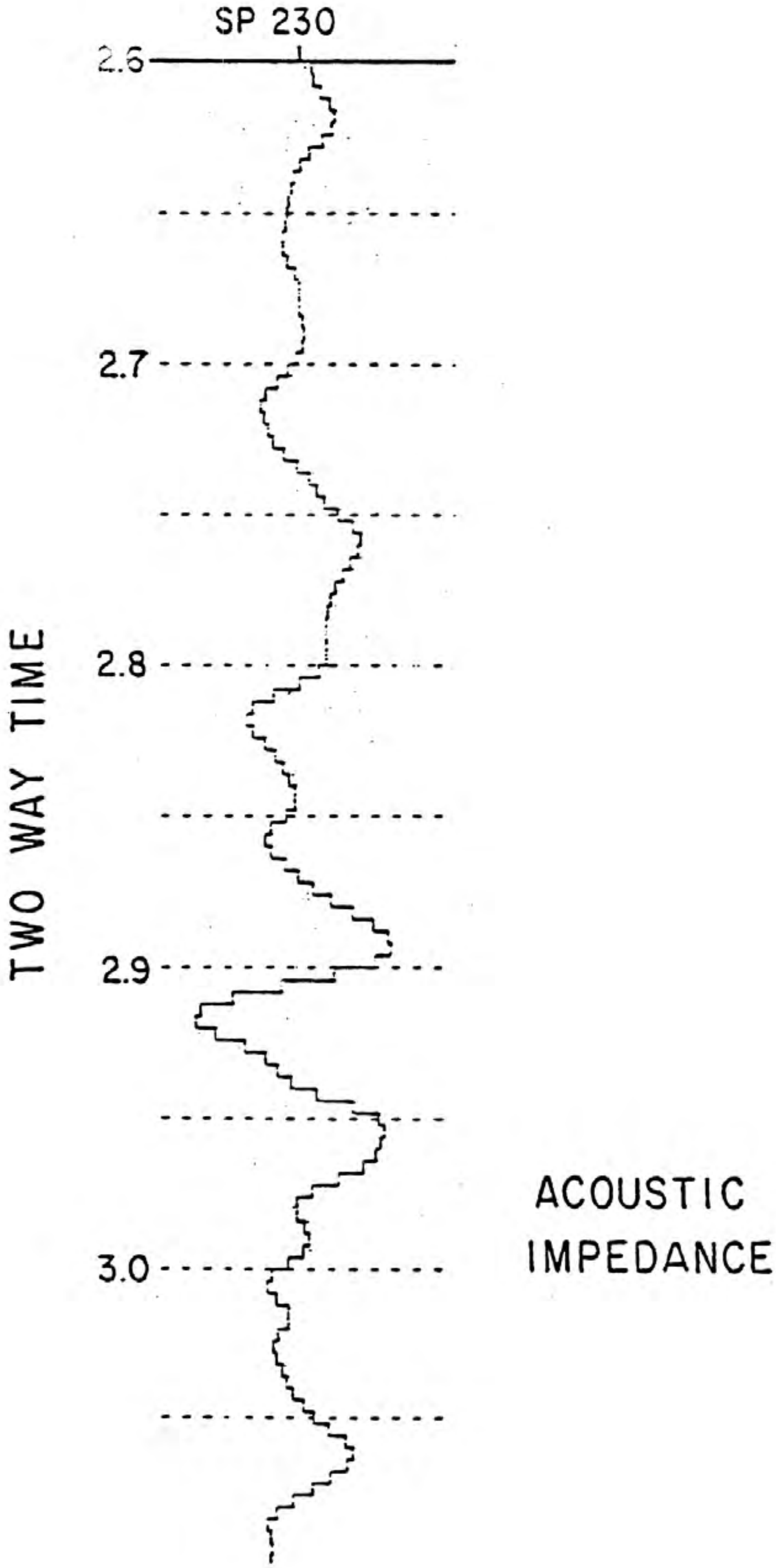

Figure 28. Relative acoustic impedance from SP 230.

well because their bandwidths are similar. The correlation between the acoustic impedance log from SP 230 (Fig. 28) and the log from the synthetic seismogram (Fig. 27) is good, considering that the bandwidths of the two logs are different.

Figure 29 shows the synthetic acoustic impedance logs from North Sea line 1. This is not seismic data but rather relative acoustic impedance data and instead of showing interfaces, it shows intervals and a measurement of their relative acoustic impedances. An arbitrary value is chosen as a base value for each log; deflections to the right with black shading simply indicate larger values of acoustic impedance than deflections to the left. Figure 30 represents further refinement of the integrated acoustic impedance logs and is obtained by filtering the relative acoustic impedance logs to achieve a block-like

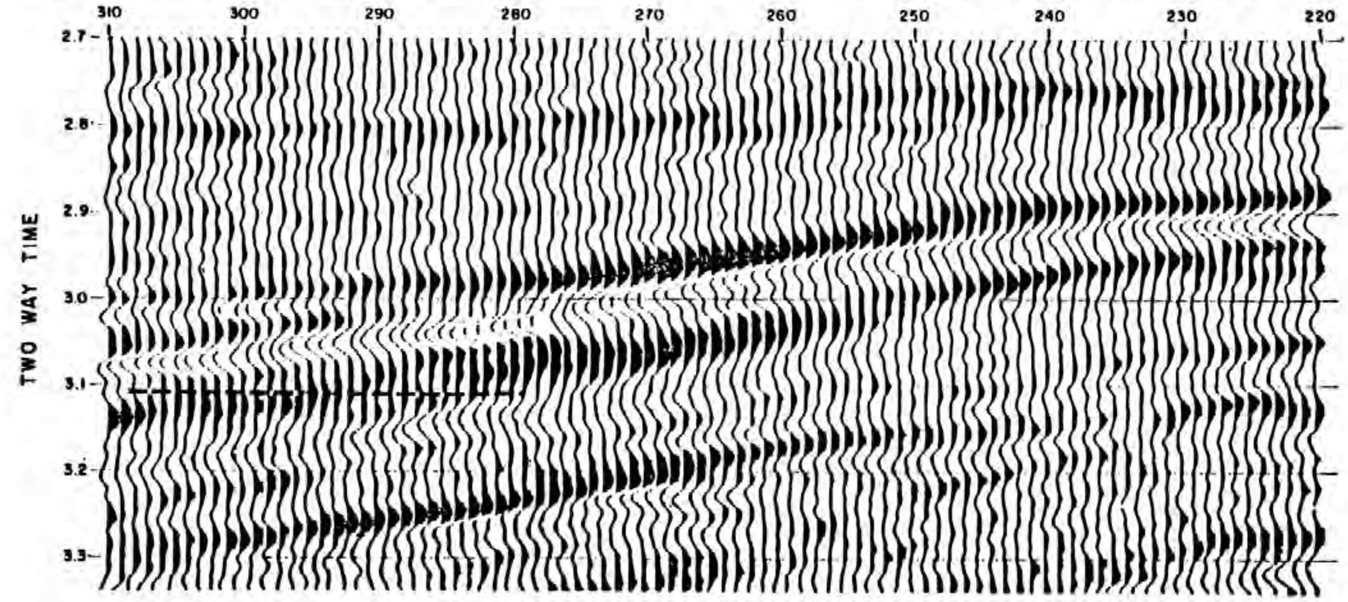

Figure 29. Acoustic impedance logs from North Sea line 1.

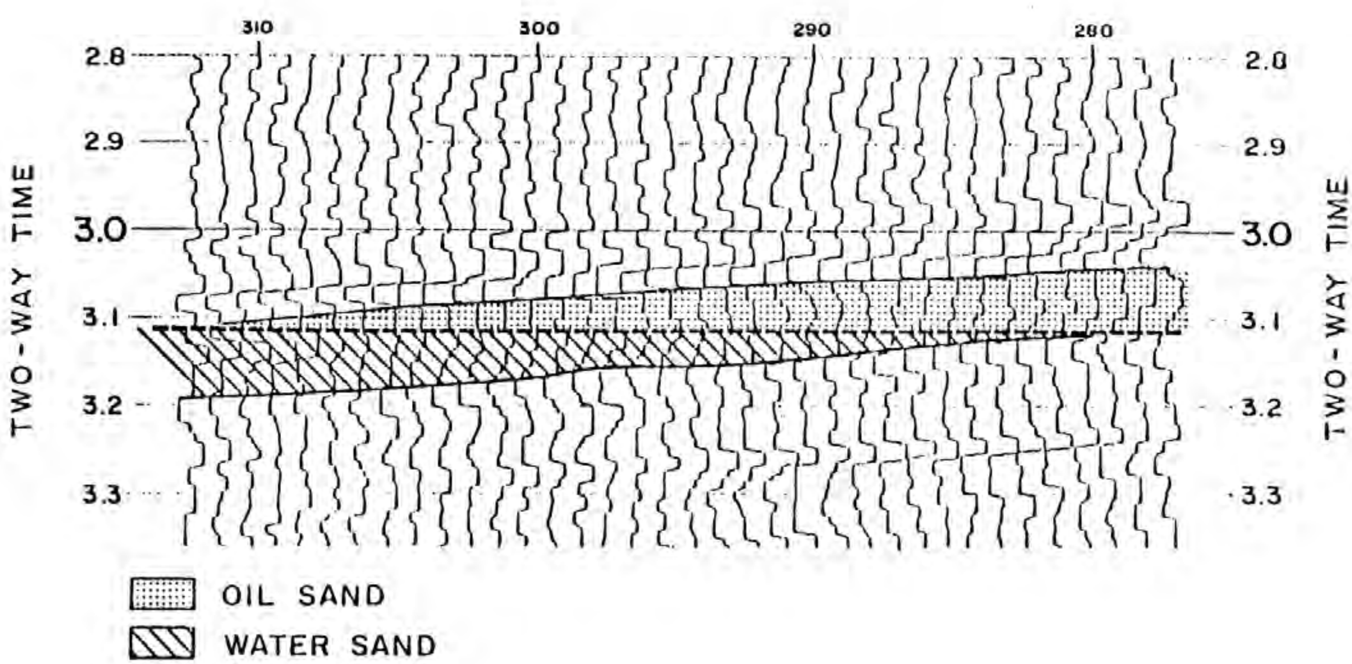

Figure 30. Acoustic impedance square plots from North Sea line 1.

appearance. Relative impedances are preserved and impedance boundaries are more pronounced.

The low acoustic-impedance radioactive shale appears just below 2.9 seconds at SP 230 on the acoustic impedance section (Fig. 29). It appears to interfinger with the higher impedance ordinary shale that is downdip between SP 287 and SP 310. The higher velocity ordinary shale is above the radioactive shale and is the black event just above 2.9 seconds at SP 230. Below the radioactive shale is the oil sand at SP 230; it appears as a large acoustic impedance interval below 2.95 seconds. The oil sand appears to thicken going downdip, the impedances weaken between SP 290 and SP 307, and a higher impedance interval appears below the oil sand. The dashed lines on Figures 29 and 30 show the interpretation of a proposed oil-water contact, where the observable change in acoustic impedance could be due to chemical action and mineralization at the contact. The oil sand appears to pinch out at about SP 313.

LITHOFACIES MAPPING

The SYN-LOG section shown in Figure 31 demonstrates a different approach to stratigraphic geophysics. This section shows the lithofacies relationships in the section, which allow structural mapping of the stratigraphic units. In fact, traditional structural mapping of some reflector in these data would not make sense without first doing this type of evaluation. The deflections to the left in the upper part of the section indicate suspected sands which are encased in a higher velocity shale. The deflections shown in the lower part of the section indicate facies which are harder than the surrounding shale and evidence a major change in the stratigraphy of the unit. Therefore, the major concern must be mapping the units rather than a single reflector.

CONCLUSIONS

Throughout this paper a distinction between exploration and exploitation has not been made, and it should be clear that the advances in seismic technology which have been discussed here do not solely apply to exploration. The more well data with which to calibrate the seismic data, the better will be the mapping of the reservoir. This will make seismic data as important to the

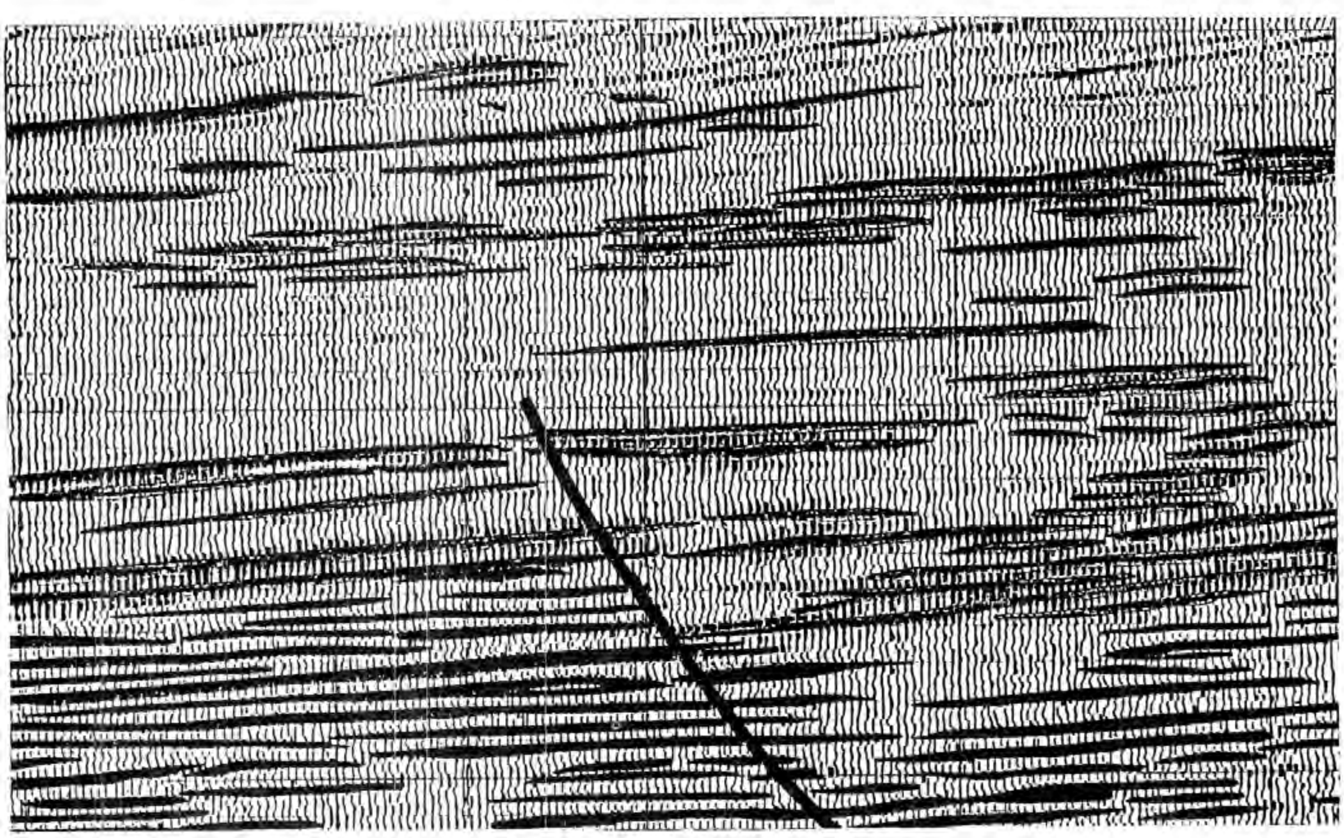

Figure 31. SYN-LOG section showing lithofacies relationships in the section.

reservoir engineer as it is to the exploration geologist. More importantly, calibration with good reservoir data allows determination of the resolution to be expected from seismic data when hunting new, but similar, targets.

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