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1963 ORGANIZING DIRECTORS
Harold Vance, President
William Hurst, Vice President
Herbert F. Poyner, Jr., Sec.-Treasurer

1964 OFFICERS AND DIRECTORS
H. J. Gruy, President
Jack A. Crichton, Vice-President
Harry L. Dedman, Sec.-Treasurer
K. M. Fagin, Director
Harold Vance, Director
William Hurst, Director
Herbert F. Poyner, Jr., Director

1965 OFFICERS AND DIRECTORS
Jack A. Crichton, President
C. H. Keplinger, Vice President
Thomas M. Berte, Jr., Sec.-Treasurer
Roger Hamel, Director
H. J. Gruy, Director
K. M. Fagin, Director
Harry L. Dedman, Director

1966 OFFICERS AND DIRECTORS
C. H. Keplinger, President
Roger Hamel, Vice President
Thomas M. Berte, Jr., Sec.-Treasurer
Frank E. McGonagill, Jr., Director
Fred L. Oliver, Director
Wallace O. Keller, Director
J. J. Arps, Director

1967 OFFICERS AND DIRECTORS
J. J. Arps, President
Fred L. Oliver, Vice President
Frank E. McGonagill, Jr., Sec.-Treasurer
Wallace O. Keller, Director
J. Donald Clark, Director
Jerome J. O’Brien, Director
Gerald E. Sherrod, Director

1968 OFFICERS AND DIRECTORS
George W. Taylor, President
Norman J. Clark, Vice President
J. Donald Clark, Sec.-Treasurer
T. W. McGuire, Director
Jerome J. O’Brien, Director
Gerald E. Sherrod, Director
William H. Spice, Jr., Director

1969 OFFICERS AND DIRECTORS
T. W. McGuire, President
A. M. Derrick, Jr., Vice President
Walter P. Jensen, Jr., Sec.-Treasurer
Norman J. Clark, Director
A. E. Smith, Director
Wm. H. Spice, Jr., Director
George W. Taylor, Director

1970 OFFICERS AND DIRECTORS
A. M. Derrick, Jr., President
John R. Brack, Vice President
Walter P. Jensen, Jr., Sec.-Treasurer
William T. Ford, Director
A. E. Smith, Director
Joe E. Laird, Director
Charles D. Schutz, Director

1971 OFFICERS AND DIRECTORS
John R. Brack, President
Fraizer M. Stewart, Vice President
E. Ralph Daniel, Sec.-Treasurer
William T. Ford, Director
Joe A. Laird, Director
Charles D. Schutz, Director
Myron H. Willits, Director

1972 OFFICERS AND DIRECTORS
Fraizer M. Stewart, President
E. Ralph Daniel, Vice President
J. Donald Clark, Sec.-Treasurer
Edward A. Albares, Director
George A. Stovall, Director
Jack D. Schafer, Director
Myron H. Willits, Director
1973 OFFICERS AND DIRECTORS
J. Donald Clark, President
Robert O. Franklin, Jr., Vice President
Harry L. Dedman, Sec.-Treasurer
Edward A. Albares, Director
George A. Stovall, Director
Jack D. Schafer, Director
Norman A. Olansen, Director

1974 OFFICERS AND DIRECTORS
Thomas M. Bertch, Jr., President
Joseph P. Watson, Jr., Vice President
Tom G. Calhoum, II, Sec.-Treasurer
Peter C. Petrousson, Director
Robert O. Franklin, Jr., Director
Harry L. Dedman, Director
Norman A. Olansen, Director
**MEMBERSHIP BY STATES**

**ALABAMA**
- Mobile
  - Petrouson, Peter C.

**CALIFORNIA**
- Los Angeles
  - Evans, Barry L.
  - O'Brien, Jerome J.
- Manhattan Beach
  - Baldwin, Elwood L.
- San Francisco
  - Martin, Larry L.
- South Pasadena
  - van Wingen, Nick

**CANADA**
- Calgary, Alberta
  - Lowe, Howard R.

**COLORADO**
- Denver
  - Blancett, Kenneth S.
  - Ferry, John H.
  - Frawley, David A.
  - Leach, William H., Jr.
  - Magnie, Robert L.
- Englewood
  - Duchscherer, William, Jr.
  - Littleton
  - van Pooallen, Handrik Karl

**IDAHO**
- Boise
  - Grimm, Richard Dean

**ILLINOIS**
- Chicago
  - Burnett, Peter G.

**KANSAS**
- Wichita
  - Fair, F. Doyle
  - Stovall, George Alston

**LOUISIANA**
- Lafayette
  - Bates, Fred W.
  - Bercegeay, E. Paul
- New Orleans
  - Bowling, Leslie
  - Meltzer, Lee Hillard
  - Miller, John Cummins
  - Simmons, Fred E., Jr.

**LOUISIANA (cont'd)**
- Shreveport
  - Branner, Leo Robert, Jr.
  - Billingsley, David L.
  - McGuire, T. W.
  - Waddle, Paul Raymond

**MICHIGAN**
- Jackson
  - Simon, Gerald D.

**MISSISSIPPI**
- Jackson
  - Mayer, Harold R.

**MISSOURI**
- Kansas City
  - Hall, A. L.

**NEW YORK**
- New York City
  - Chandler, John T.
  - Olansen, Norman A.
  - Sherrod, Gerald E.
  - Stewart, Fraizer M.
  - Wier, Joseph R.

**OKLAHOMA**
- Oklahoma City
  - Mann, Hobson S.
- Tulsa
  - Cobb, Henry E., Jr.
  - Davies, David C.
  - Earlougher, R. Charles
  - Ford, William T.
  - Godsey, Dwayne E.
  - Howard, Thomas C.
  - Hudson, Edwin Jay
  - Jackson, Ralph Wayne
  - Keplinger, Charles H.
  - Kravis, Raymond F.
  - Mueller, Joseph Fred
  - Russell, Gerald W.
  - Southmayd, William C.
  - Wanenmacher, J.M., Sr.
  - Wanenmacher, J.M., Jr.
  - Willits, M. H.

**NORMAN**
- Campbell, John C.

**TEXAS**
- Austin
  - Dedman, Harry L.
  - Smith, Sol
TEXAS (cont'd)

Big Spring
Penner, Robert F.
Corpus Christi
Beaver, M. H.
Fly, J. Paul
Dallas
Arps, John J.
Bednar, William C.
Brack, John Ray
Bridges, Philip M.
Calhoun, Thomas G., II
Clark, Norman J.
Crichton, Jack A.
Fagin, Kyle M.
Franklin, Robert O., Jr.
Garb, Forrest A.
Jeffrey, Thomas J.
Lamoreaux, William E., Jr.
Linder, John D.
Oliver, Fred L.
Ritts, Howard J., Jr.
Schafer, Jack D.
Smith, Aurel E.
Vaughan, Joe E.
El Paso
Derrick, A. M., Jr.
Fort Worth
Keller, Wallace P.
Peterson, L. F.
Houston
Bertch, Thomas M.
Brennan, Raymond H.
Brinkoeter, William R.
Brown, Charles W.
Brown, W. Emmett
Cantrell, Cyrus D., Jr.
Cary, Thomas L.
Carroll, Alton J.
Clark, J. Donald
Colle, Jack O.
Cooke, Milton M.
Crego, William O.
Daniel, E. Ralph
Derouen, Gordon A.
Elsbury, Joe W., Jr.
Foster, Frank M.
Grandall, Kenneth G.
Gruy, Henry J.
Hall, Donald L.
Harding, Henry W.
Hooper, William C.
Hubbell, Robert O.
Hurst, William
Jensen, Walter P., Jr.
Keplinger, Henry F.

Houston (cont'd)
Laird, Joe A.
Lowe, John P., Jr.
Mefford, Nace F., Jr.
Miller, Leland E.
Moredock, S. Kenneth, Jr.
Neale, John W.
Newton, Paul F.
Parkers, Sidney A.
Poyner, Herbert F., Jr.
Pressler, Edward D.
Ridley, Robert P.
Sims, Henry L.
Taylor, George W.
Vance, Harold
Watson, Joseph P., Jr.
Zeid, Marvin C.
Midland
Moore, J. Hiram
Odessa
Edwards, G. W.
Jarrell, Malcolm
San Antonio
Clevenger, Paul R.
Schutz, Charles D.
Spice, William H., Jr.
Victoria
Hamel, Roger C., Jr.
Weatherly, Justin E., Jr.
Wolfe City
Nichols, Earl A.

VIRGINIA
McLean
McCord, David R.

WASHINGTON
Albarez, Edward A.
Hamilton, Clarence E.
Hughes, James D.

TEHRAN, IRAN
Anders, E. L., Jr.
Phillips, Charles E.
"Reports by Drilling To Their Investors"
by James W. Lacy

"Outlook for LNG and SNG Projects"
by Robert L. Purvin

"The Drilling Program Industry - Its Status and Analysis"
by Robert C. Metzger

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by Anton Roeger, III

"Practical Evaluation Gamesmanship"
by John M. Campbell

"Buying Oil and Gas Production - Technical and Psychological (The Buying Mood)"
by Marvin C. Zeid

"What's the Price of My Crude Oil?"
by John R. Brack

"The Subsidiary Equation"
by William Hurst
HISTORY

There has long been a need for a Society which would bring together for their mutual benefit the specialists in petroleum evaluation engineering. Realizing this need, Harold Vance, William Hurst and H. F. Poyner, Jr. secured a charter from the State of Texas for such a Society which is known as “The Society of Petroleum Evaluation Engineers.” The number of the charter setting up such a corporation is No. 187252 and was issued by the Secretary of the State of Texas on September 24, 1962.

This corporation was chartered under the Texas Non-Profit Corporation Act and its period of duration is perpetual. The corporation was organized exclusively for educational purposes and to promote the profession of petroleum evaluation engineering, to foster the spirit of scientific research among its members, and to disseminate facts pertaining to petroleum evaluation engineering among its members and the public.

The various, technical associations, such as the American Institute of Mining, Metallurgical, and Petroleum Engineers, the American Association of Petroleum Geologists, and even the requirements of our engineering laws, provide no measure of the experience and ability of an individual in petroleum evaluation. Therefore, a need for this specialized Society is self-evident.

MEMBER QUALIFICATIONS

Any person with a bachelor’s or advanced degree in engineering or geology, duly licensed by his state as a professional engineer or geologist and ten years’ experience in the evaluation of oil and gas properties may qualify to become a member. In the event his state has no professional engineering or geological license laws, the person shall be able to meet the requirements for a license in either of these categories in another state having such laws. Also, a person may substitute five years’ responsible petroleum engineering experience or teaching of the subject in a college or university of recognized standing for five years’ experience in the evaluation of oil and gas properties.
THE PRESIDENT'S PAGE

Our Society is now twelve years old and our present and continuing problem seems to be securing of proper recognition of our member's qualifications by financial institutions and producers. If the presently proposed program of the USGS which requires annual reporting of developed and undeveloped reserves by each producer, is adopted we should endeavor to have our members available to implement this program.

In view of our membership requirements it is gratifying to note that our membership has increased by 10 to 15% during the calendar year.

The exchange of ideas at our monthly meetings and our annual meetings has been mutually beneficial and our last annual meeting which was held in Mexico City was very successful.

Our Journal this year is a combined publication covering the previous three annual meetings. I would like to express the Society's appreciation to all of the authors, to the editorial committee and to our secretary all of whom contributed to the completed effort. This Journal fulfills one of the principle aims of the Society.

I have greatly enjoyed this year as president and I have been very pleased with the excellent cooperation I received from all of the membership.
Perhaps the prime factor in America's attainment of her high standard of living was the abundance of cheap energy on which to build her industrial might. Petroleum was-and still is-the source of most of that energy. Development and utilization of our petroleum reserves occurred in the past when individuals and companies, often relying on engineering evaluations of potential profit, risked capital to test the unknown strata of our land.

Risk of private monies on oil and gas drilling and property purchases occurred because proper economic incentive was present. To continue the necessary exploitation of our oil and gas reserves, we believe it essential that pricing, taxing, and regulating policies of our Government always insure that private venture capital be openly attracted by high probability of adequate return. The punitive atmosphere prevailing in congress today must be replaced by realization of petroleum's vital role in our country's well-being, and the acknowledgement that private capital, under proper motivation, can do the best job to supply that petroleum.

An important part of our past, the independent oilman, is again returning to the scene. With the rise in new crude price and intrastate gas prices to reasonable levels, the independent will risk money to probe for, discover, and produce reservoirs often too small for consideration by major producers. Higher field prices have also stimulated interest in secondary and tertiary oil projects. And, of course, oilmen from the Doc Joiner type to Exxon Managers are busily drilling and fully developing primary reserves which had been uneconomic under old prices.

Where do we, as evaluation engineers, fit into present and near-future activity? Frankly, we predict that we will become an even more important segment of the petroleum industry. Demand for our services has recently increased, solely as a result of more activity in the industry. Further changes in Federal Laws are being contemplated by congress which will add to our work load. Unfortunately, deeper erosion or total elimination of statutory depletion may transpire. Should this occur, many small operators and most royalty owners will consider selling producing properties, at least to the point of having evaluations performed. The buyer will be able to pay a price higher than the seller's discounted cash flow because of the application of cost depletion. Additional properties will be on the market if the capital gains tax rule is revised to lower taxes for property owned several years. This type of capital gains tax change should generate a considerable volume of trading, since knowledgable owners will realize the probable temporary nature of the opportunity.

During this time of great activity in our industry, higher demand for our special expertise will undoubtedly continue. As the only organization which requires that each member have at least a decade of petroleum evaluation experience, plus a geological or engineering degree with professional registration, The Society of Petroleum Evaluation Engineers rightfully should be the proper reference for those seeking petroleum property evaluations. In this regard, we request that SPEE Members attempt to inform the petroleum and financial communities of SPEE's unique professional position. On a broader front, our society
could undertake a formal program to notify, by advertising if necessary, other professional groups and industries of our existence.

On a person-to-person basis, we can enhance our stature by stressing professionalism. For example, SPEE's By-Laws clearly discourage "quickie" evaluations (see Principles of Acceptable Evaluation Engineering Practice,Art.II,3). Yet many of us acquiesce to friend's requests in providing "rule of thumb" estimates on unfamiliar properties, usually for free. It is doubtful that such an "evaluation" is really a favor for the requester, who often ignores your warnings about the variability for the estimate, and fixes the quantity firmly in his head for negotiating purposes. Such situations could be avoided by performing properly-detailed studies, or by referring the friend or client to a SPEE Member knowledgeable of the area.

The current issue of the Journal of the Society of Petroleum Evaluation Engineers is Volume IV, and includes transactions of our annual meetings for 1971, 1972, and 1973. Papers presented at those meetings are chronologically arranged in this issue. The prior journal, Volume III, was dated 1970-1971, and reported on society affairs to that time.

We note with justifiable pride that membership over the last year has risen from 124 to 142 members, an increase of 18 influential and qualified people. Such solid growth is indicative of the society's ability to provide a unique function in the petroleum industry. Fortunately, no end to that growth is in sight.

1974 EDITORIAL COMMITTEE:

J. Donald Clark, P.E., Chairman
Robert O. Hubbell, P.E.
William Hurst, P.E.
Robert P. Ridley, P.E.
REPORTS BY DRILLING PROGRAM TO THEIR INVESTORS
By James W. Lacy, Abode Corporation, Midland, Texas
Presented at the Ninth Annual Meeting of
The Society of Petroleum Evaluation Engineers
Houston, Texas, November 1971

There are four basic types of reports that are generally furnished to an investor or participant in a drilling program. These are: the progress report; tax report; development well request; and an appraisal or evaluation report. In discussing each of the reports, if I refer primarily to what Abode does, it is because I am most familiar with our reporting method and not because I have not reviewed what other drilling programs use. Additionally, if I make editorial comments, please accept them as such.

PROGRESS REPORT - The progress report may take many different forms. It ranges from a simple drilling report, much like a company daily drilling report, to a three or four page epistle complete with maps. It can be furnished monthly, quarterly or intermittently.

Communication, a much used word nowadays with the investor or participant may appear rather simple since it should suffice to report the facts. Such is not the case. In our opinion, you must first describe the typical investor before you can design the report. He is generally a busy, smart, harried business man. He is well informed on investing, but practically uninformed about the oil business. Last, in most cases, you will have little or no personal contact with the investor. Both the legal and public relation aspects of the report must be considered. The facts must not be embellished, yet your sales force does not want us "to put a basket over the light."

In our shop, we have decided that "simplicity" is the key word. We report monthly while drilling is in progress in a particular program and quarterly thereafter. Our report is similar to a daily drilling report in style, but is written in layman's language. We describe the wells as wildcats or semi-proven. We report the well production as "pumping 60 barrels of oil per day" in place of its potential or "flowing 1,500,000 cubic feet of gas per day" and write out the words in lieu of the magic symbols of BOPD or MCFGPD. If financial data is reported, we stay on a cash basis. Investors are kind of like my wife. She's not interested in how much we make, only the cash she gets - so is the investor. We report income net of everything except federal income tax. In keeping with the idea that the average businessman has more reading than he can complete, we try to get our report on one typewritten page. It is easily filed or thrown away then.

From time to time, we include some oil news, a plug for the oil industry, and, if appropriate, a little oil-field humor. We want the report to be "newsy", not stilted with engineering and industry terms.

TAX REPORT - The tax report is a more formal report and is prepared by the public accounting firm. It is submitted almost without exception on a calendar year basis. The report should contain the program's financial results for that specific year. It should reflect the oil and gas sales, production taxes, intangible drilling costs, depletion and depreciation and the taxable income or loss which can be entered directly on Schedules "C" or "E". If investment credit is available, this should be reported. It should contain a depletion and depreciation schedule. Our report includes a schedule showing the specific income or (loss) to be reported by a $5,000, $10,000 or $50,000 unit in the program. We include a cover letter and elaborate on any item of consequence. We further state that no First Year Depreciation under Sec. 179 of the IRS code is taken. Thus, if a taxpayer wants to recalculate his depreciation, an additional charge-off may be available on an individual basis.
DEVELOPMENT WELL REQUEST - When there are development wells to be drilled, the investor must be furnished an Authority For Expenditure or development well request. We attempt to drill as many development wells as possible with the original program funds, since most investors do not like overcalls. However, if overcalls are made, the investor must be given as many useful tools as possible. Asking the average investor to make a drilling decision is a bad deal to begin with, but without adequate information, it's worse. The AFE should include a map, a geological summary, a cost estimate, the estimated return and an estimated payout schedule. Quite often with all of this information and a perfectly obvious offset situation, they will still turn down the request.

APPRaisal REPORTS - An appraisal or evaluation report is generally furnished to the investor by most drilling programs. These can either be independent appraisals prepared by an outside consulting firm or the inhouse variety. We believe the independent appraisal is preferred. The report has many uses for both the program operation and the participant. Most of these are apparent, but I will mention a few. They are:

1) Establishment of a purchase price;
2) Loan purposes;
3) Estate evaluation;
4) Establishment of a gift value;
5) AFE use.

We use a nationally recognized firm to appraise our program. In addition to furnishing them the usual well records, logs, pressures, etc., they are furnished our daily drilling report so that they may be familiar with our properties from the beginning. We request not only that the appraiser establish the reserves and develop a cash flow stream, but, also furnish a fair market value of the participation as of the appraisal date. We request the fair market value figure so that our investors are not confused with the present worth figure. Our appraiser uses a number of criteria to determine the FMV, but it falls in the range of 2/3 DCF and a pre-tax average annual rate of return of 15%.

Several programs furnish their investors with Cash Liquidating Values. These are furnished where there is some type of redemption offer. These values are generally set at a specific discount below the FMV. In other words, they will be 5%-10% lower than the FMV.

NORMAL RETURN - While I've discussed the various reports furnished investors, I would like to take the liberty of suggesting a topic for investigation by one of your study groups. The investors need a "normal income pattern" to compare the results of various programs; it would be primarily a statistical study and could be expressed in percent of pre-tax investment returned each year. For example, the "normal or standard return" on a $10,000 pre-tax participation might be:

<table>
<thead>
<tr>
<th>Amount</th>
<th>Percentage</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>$3000</td>
<td>30%</td>
<td>1st year</td>
</tr>
<tr>
<td>$2000</td>
<td>20%</td>
<td>2nd year</td>
</tr>
<tr>
<td>$1500</td>
<td>15%</td>
<td>3rd year</td>
</tr>
<tr>
<td>$1200</td>
<td>12%</td>
<td>4th year</td>
</tr>
<tr>
<td>$1000</td>
<td>10%</td>
<td>5th year</td>
</tr>
<tr>
<td>$850</td>
<td>8.5%</td>
<td>6th year</td>
</tr>
</tbody>
</table>

In this example, payout on the gross investment would be 6+ years and if his participation was doing better or worse than the normal pattern, it would be readily apparent. The investor knows his own tax rate and could then develop his own after-tax return requirements.
OUTLOOK FOR LNG & SNG PROJECTS
By Dr. Robert L. Purvin, Robert L. Purvin & Associates, Inc.
200 Park Avenue, New York, New York 10017
Presented at the Ninth Annual Meeting of
The Society of Petroleum Evaluation Engineers
Houston, Texas, November 1971

I have been asked today to bring you up to date on the LNG and SNG projects currently being pursued and sketch for you the outlook for gas from these sources. Nothing would give me greater pleasure than to be able to tell you that many projects are being actively pursued and that in the very near future we can expect large quantities of substitute natural gas supplies sufficient to fill the gap between supply and demand anticipated over the next decade. Unfortunately I can't do that. There have been many exciting developments in these fields and many interesting projects have been suggested but unfortunately indecision on the part of the industry and bureaucratic red tape, as well as the lack of an over-all national energy policy, which, of course, is a major contributor to the industry's difficulty in making the necessary commitments, finds us with very few projects committed on a firm basis and with little prospect of much gas forthcoming under the best of circumstances prior to 1974, and at the rate we are going, no meaningful quantities of gas much before 1976 or 1977. In other words these alternate sources of substitute natural gas will offer very little help in alleviating the expected shortage of clean energy in the near future.

I am sure everyone here today is familiar with the anticipated energy crisis. As a matter of fact, one of the other speakers will undoubtedly summarize this situation. During August here in Houston, I, myself gave a paper in which I attempted to summarize our problem and describe the place of substitute natural gas in the market and the problems inherent thereto. Rather than attempt to repeat much of what I said at that time, I have brought along copies of that paper for those of you who are interested. While it would be presumptuous of me to classify this paper as "must reading", I think it will help you to understand why we have made so little progress in bringing substitute natural gas into the market. The principal point that I tried to make is the fact that all of these alternate sources of natural gas are going to be expensive, in other words, substantially more than we have paid for natural gas produced in the lower 48 states in the past. But, "expensive" is a relative term and it is interesting to note that most of these alternate sources will not be much more expensive than I expect gas will cost delivered into the market from the Alaskan North Slope or from the Canadian Arctic regions. As a matter of fact, by the time the price for future discoveries of domestic natural gas supplies are set, assuming fair compensation for cost and risks involved, these substitute gases may not be much more expensive. Unfortunately, the gas industry has been and continues to be guilty of wishful thinking, namely by some "stroke of luck" or technical breakthrough and in my opinion it would have to be almost a miracle, we will develop cheap gas supplies or for that matter some other energy source of a comparable quality. Obviously, as long as there continues to be this hope that ample cheap supplies of gas, or other ecologically acceptable fuel will be made available there is great reluctance to make the necessary commitments to highly capital oriented high cost gas supplies. The domestic producing industry has unfortunately helped foster this idea because in their zeal to fight for higher gas costs at the wellhead, they have claimed that at a reasonable price all the natural gas that we could ever require would be forthcoming in short order. Frankly, I doubt this. For many political and economical reasons it now appears to me that there is no way that we will be able to meet our total gas need in the foreseeable future, say within the next ten years. I can only hope that full realization of this problem will result in greater willingness on the part of the industry to push ahead on all fronts in a decisive manner so at least reasonable
quantities of gas might be forthcoming from all of the potential sources so as to prevent the energy shortage from becoming a real catastrophe.

There are basically three sources of supplemental fuel supplies which I would categorize as substitute natural gas, namely LNG which, of course, is not really substitute gas but it is natural gas put in a convenient liquid form in order to transport the gas over long distances by ship; gasification of liquid hydrocarbon fractions and gasification of coal, which technology would also be applicable to lignite, tar sands or very heavy gravity crudes and fuel oils.

Industry, as well as government studies through the past several years, has pointed up the facts that these alternate supplies are generally from relatively independent sources and that the time schedule for delivery vary widely but that none of them can reach the market in any volume in less than two or three years. It is apparent that all of them will be fairly expensive and there is little chance that gas from any of these sources will actually reach the marketplace for much less than $1.00 per million BTU's. Of special importance is that these various sources vary considerably in security of supply due both to mechanical as well as political factors. Unfortunately, the very fact that there are several potential sources of supply causes considerable confusion and indecision and gives some politicians and corporate executives amply cause for delaying decisions. I have heard the comment that since it's going to take so long to bring the various sources of gas to the market the necessary investigations should only be a minor factor in the ultimate delivery date. Unfortunately, the discussions, studies, hearings, etc., appear to be almost endless, and it is already apparent that the commercial and political decision-making mechanism will undoubtedly occupy a considerable percentage of the time required to commercialize these sources.

The two most important factors being considered in making judgement on these various new sources of supply are price and security. The timing factor for bringing the various potential sources into the market does not appear to be receiving near the attention it should, mainly because the quickest potential sources could also be the least secure. For example, import LNG presents unknowns which raise problems on which there is no past experience. For this reason, in recognition of the fact that such sources will undoubtedly require considerably greater time for acceptance and approval, the time difference for ultimately bringing the various sources to the market may not differ too much. Also there is still enough mystery surrounding the longer term sources of gas, both domestic and foreign, to permit the hope that they might actually be cheaper if we could simply find the time to finalize their development. This is particularly true of coal gasification which is, of course, the only true domestic source of supply of substitute natural gas. Generally speaking, the question of price is largely a domestic political problem since the state and federal governments have generally strongly exercised their mandate to protect the public. Unfortunately, the government in its zeal to keep prices down has badly miscalculated and therefore is largely responsible for the impending energy crisis. We can hope that they've learned something from their past mistakes but it is essential that we recognize that these bodies are largely political and are therefore required to fight for the lowest possible prices.

Our security of supply has never been a major problem in the past where domestic gas has been involved. The policy has been to provide as much assurance as possible that there will be the minimum of mechanical problems. Extra investment and costs has always been permitted to insure this continuity of supply but, of course, in the past these extra costs have been only one or two pennies rather than possibly an order of magnitude greater, as it could be with most of the substitute sources.

Political security is a relatively new matter with respect to natural gas but it is, of course, a broadly discussed problem in the crude and unfinished oil supply programs. On the other hand, the problem in the past has largely been the protection of the domestic producing industry
rather than assurance of supply to the consumer in an energy-short economy. This new problem, of course, can be argued either way:

1. Because we are short of energy, we will have to relax the security problem and be satisfied with any of those sources available to us, or

2. The American public can't be asked to depend on a supply which might be interrupted and cause wide disruption; rather we should build our energy program on a sounder base even if it might take a little longer and cost a little more.

Import LNG is the most apparent supply of supplementary gas and at least one small project will be underway before the end of the year, namely Distargas based on Algerian LNG. However, if we do not early establish the availability and dependability from several of the sources of LNG, the other alternates can be expected to be pushed. Coal gasification is, of course, the main hope for domestic supply and even today, "at a price", substantial quantities of clean energy could be brought to the market in a five to seven year period. The recently announced El Paso project and the Texas Eastern/Pacific Lighting/Utah International project are examples of consideration of this approach. Frankly, the cost will probably be astronomical on the basis of present day technology and it can therefore be expected that if we have any alternate dependable sources, it would be desirable to delay this effort until the technology has been better established resulting in a more economical supply ultimately from this source.

In view of our already crude short situation in the U.S., the principal justification for considering crude oil gasification is to buy some time for the development of coal gasification. In addition crude oil gasification may be the best method of utilizing many of the heavy gravity, high sulphur crudes throughout the world, but at the moment, there is probably no great urgency to solve this problem. The fact that the problem will undoubtedly exist, however, does make the gasification of crude oil worthy of consideration at this time since the facilities will, in the long term, have an alternate use for the utilization of such distressed crudes in the U.S. and Canada. These known reserves will probably support no more than one or two units of this type and therefore any larger program would have to depend on offshore import of crude oils which has the same political problems as LNG. On the other hand, because there are many sources of supply of crude oil throughout the world there is some security in diversification of supply sources which will undoubtedly be viewed more favorably than the rather specific supply sources of LNG. In regard to crude oil gasification, it should be understood that while the technology is generally well-known, these facilities have never been put together in just this process sequence and because of the relatively large capital investment involved, there is and will be considerable inertia in accepting this process. Again, I do not expect there to be a really large volume of crude oil gasification built because of the short domestic supply of the basic raw material. But because of the relatively rapid development of such a project, namely three or four years, it could be a major source of early supply.

The gasification of naphtha can be categorized with that of crude oil although generally speaking it should be even more limited than crude gasification. Currently it is exciting because it not only is the quickest thing that can be installed, namely within two to three years, but it also offers a peaking and seasonal supply ability which does and will have long term value in the U.S. gas program. Supply of naphtha is no more limited than the general supply of crude oil because it is a semi-finished hydrocarbon but its use in gas must compete with alternate uses for this component of the crude. I personally believe that it will be the most expensive of all of the substitute natural gas sources except in those cases where its special seasonal flexibility is utilized.

Now lest you feel that nothing is being done in the field of LNG and SNG, let me assure you that some progress is being made although as I have noted previously not nearly enough to have a real impact on our supply problem. In the case of LNG there are three projects in operation and
two others under construction and scheduled for operation within the next eighteen to twenty-four months. The Camel plant at Arzew, Algeria produces 150 million cubic feet per day of LNG equivalent and delivers 100 million cubic feet per day to England and 50 million cubic feet per day to France. This plant has been operating since 1964. Phillips & Marathon have operated a plant to the Cook Inlet of Alaska since 1969 delivering 140 million cubic feet per day to Tokyo Electric and Tokyo Gas. Esso started a plant in Libya the early part of 1971 for delivery of 235 million cubic feet per day to Italy and 110 million cubic feet per day to Spain. The first two projects started up smoothly and have operated to date without any major incident. The Esso project on the other hand suffered both mechanical and political problems which are only recently being resolved. A 500 million cubic foot per day plant is under construction at Skikda, Algeria of which 70% is destined for delivery to France and 30% to United States via the Distirgas program previously mentioned. Shell Oil Company is constructing a 500 million cubic foot per day plant in Bruni for delivery to Tokyo Gas and Osaka Gas in Japan.

In addition to these committed projects there are several other projects which are on the drawing boards or under consideration. Additional capacity is being considered at Skikda as is a second train at Cooks Inlet, Alaska. Sonatrach, the national oil company of Algeria, has committed themselves to construct a billion cubic foot per day plant for a program sponsored by El Paso Natural Gas for delivery to Columbia Gas, Consolidated Natural and Southern Natural Gas subject to approval by Federal Power Commission. This case is currently being heard in Washington but no decision has yet been taken nor is one expected much before the early part of 1972. As a matter of fact the Distirgas project has not yet received its approval from the Federal Power Commission. Because the initial program of Distirgas was relatively small it was expedient to undertake the construction of a terminal in Everett, Mass. and at least begin the construction of a terminal on Staten Island in the New York area prior to receiving a permit from the Federal Power Commission for the importation of LNG from Algeria. Application was made in September 1970 and the first delivery is expected this month, November 1971. This first LNG shipment delivered to the Everett terminal will be received under a temporary certificate which has been granted by the Federal Power Commission for one load only. Obviously, if the project had waited for certification the construction would still not be started and first delivery would therefore have been delayed by at least two years. Shareholders of Distirgas took a major risk in proceeding with the construction of their terminal. I am doubtful that there are many companies in the gas industry who would be so audacious.

On the other hand, we must continue to ask the question how we are going to meet our gas requirements in '72 and '73 under these circumstances. It will undoubtedly require a minimum of four years to bring the El Paso project on stream once a certificate is granted and therefore there's little hope that LNG from this source will be available much before 1976. There are other projects also being considered but since they all must go through the same routine and since they all undoubtedly will require a similar construction period, it is difficult to envision availability from such sources much before 1977 or later.

At least one major project and possibly two are under consideration in Venezuela but the ventures are not yet to the point that a presentation can be made to the Federal Power Commission for its approval. Amoco has discussed a project based on its gas discovery off the east coast of Trinidad but exploration work is still going on and I doubt that there is yet sufficient proven reserves upon which to base an economic-size operation. The Ada Oil Company group have been discussing a project off the coast of Ecuador but exploration work is still under way to develop sufficient reserves. Shell, Gulf and British Petroleum have all discussed LNG projects in Nigeria. At the moment it appears that the most possible project would involve a joint venture of British Petroleum and Shell. It is anticipated that this gas will deliver into the American market at a somewhat higher price than gas from North Africa or Venezuela due to being considerably greater distance from the U. S.
As a rule of thumb, LNG costs can be computed on the basis of three major items: transportation, liquefaction and inlet gas value. Current shipping technology and present day ship costs would indicate that transportation of LNG will cost between $.08 and $.10 per million BTU's per thousand miles. Liquefaction costs in relatively large plants, namely over 500 million cubic feet per day will undoubtedly cost $.25 to $.30 per million BTU's. And it should be expected that the inlet gas price to such projects will range from $.10 to $.25 per million BTU's. In many cases the pipeline cost alone from the field to the inlet of the plant will amount to $.05 to $.10 per million BTU's. All of these costs have increased substantially over the last several years due to worldwide inflation and it is expected that they will continue to increase unless the inflationary trends are reversed. Delivered price of LNG in the Distargas project is approximately $.71 per million BTU's. It is expected that future import programs will range between $.75 and $.80 by 1975-76 and possibly even higher, namely $.85 to $.95 if Nigerian gas is to be imported. It should be kept in mind that these LNG prices are C.I.F. and do not include the cost of terminaling, revaporizing and transporting to the specific market. Terminaling and re-vaporization alone can run between $.10 and $.15 per million BTU's even for large base load projects. Obviously, if the terminal is at any distance from the market, pipeline transportation charges must also be added. Storage costs are high, from $1.00 to $2.00 depending, of course, on the actual capital cost of the necessary tankage. Current capital costs range from 4 to 7 million dollars per billion cubic feet gas equivalent storage. In spite of these relatively high costs, however, LNG for peak and seasonal requirements should be attractive to the industry to serve the high priority residential markets. There have been no crude oil gasification projects officially announced although there are several projects being considered. Preliminary studies would indicate that gas from this source might move into the market for between $.95 and $1.00 beginning no sooner than 1974-75. On the other hand, there are several naphtha gasification projects which have been officially announced and for which application has been made to the Federal Power Commission or state regulatory bodies. Several of these are based on domestic naphtha supplies while others are based on import supplies. Those based on import supplies are concurrently discussing the modification of the present oil imports program to permit the importation of the necessary raw materials. A similar adjustment in the imports program would also be required for the crude oil gasification project mentioned previously. Ralph Snyder, acting administrator of the OIA, has suggested the possibility of the ICOP program. This would permit the granting of an allocation and license for the importation of crude and/or unfinished oil for the purpose of processing into low sulphur residual fuel oil or substitute natural gas or both. This approach has been favored because the government wants to sponsor the construction of domestic facilities for processing import crude oil rather than supporting the importation of products which have been refined or processed in foreign installations.

Specific naphtha projects under consideration are a 250 million cubic foot per day installation by Columbia Gas based on Canadian light hydrocarbons, a 250 million cubic foot per day installation by Consumers Power also based on Canadian hydrocarbons, a 120 million cubic foot per day installation by Algonquin Pipeline based on domestic naphtha, a 120 million cubic foot per day installation by Brooklyn Union also based on domestic naphtha, (both of these last two are designed, however, to run only during the six months of the winter season), a 500 million cubic foot per day project to be constructed by Texas Eastern and Consolidated Natural based on a combination of domestic and import naphthas and a 40 million cubic foot per day plant to be built by Boston Gas based on import and domestic LNG. It is interesting to note that there are many jurisdictional problems which are to be resolved in connection with these projects. The Natural Gas Act does not specifically cover the manufacture or, for that matter, the transportation of synthetic natural gas, although it has been clearly interpreted by the Federal Power Commission as falling under their jurisdiction. If it is held that it does not now fall under their jurisdiction, the Congress will un-
doubtedly pass the requisite legislation to correct this deficiency. The question still remains, however, as to whether the jurisdiction will cover only the purchase and transportation of such synthetic gases or whether it will be extended to include the manufacturing plant as well. There is even some question as to whether the facilities related to the receiving and handling of the naphtha itself might also be jurisdictional. Obviously, projects such as Boston Gas and Brooklyn Union will be free of Federal Power Commission jurisdiction since they are wholly intrastate projects. This still raises the extent to which the state Public Service Commission will exercise regulatory powers. As I have already stated the gasification of naphtha is a relatively expensive process. A good rule of thumb is that the raw material component of the cost of gas is approximately 9-1/2¢ per million BTU's for each 1¢ per gallon for naphtha and about 10-20% higher for light hydrocarbons. For installations in the order of 100-150 million cubic feet per day, the processing cost is very close to 20¢ per million BTU's. Thus for foreign naphtha estimated to initially cost 8-1/2¢-9¢ per gallon base load can be produced for approximately $1.10-$1.15. Currently domestic naphtha is somewhat more expensive, delivering into gasification plants at closer to 11-1/2¢-12¢ per gallon and therefore base load gas based on domestic naphtha would undoubtedly cost approximately $1.35-$1.45 per million BTU's. For seasonal use the raw material costs are only slightly higher but the operating costs are almost double and therefore the cost of 180 day gas based on domestic naphtha would be $1.60 to $1.70.

Last but certainly not least is coal gasification which as I noted previously, represents the only truly domestic source of supply of all the substitute natural gas sources. Unfortunately, present technology of which the Lurgi Process is probably the best known is far from optimum for manufacture of gas on an economic basis. Considerable work is being done by both government and private industry on alternate processes and one such program has been recently announced by the FMC Corporation. It is FMC's intention to organize a private consortium to study their process with the hopes that a commercial plant can be undertaken within the next two years for first deliveries approximately five years from now. In addition, the government has been working with the American Gas industry through the AGA to set up a long term study program in which some 30 million dollars per year would be spent developing the most optimum coal gasification process. Contributions would come two-thirds from the government and one-third from industry. This proposal is currently being discussed in Congress. The recovery of liquids from coal has been studied under government sponsorship and by private industry for many years and is a natural adjunct to coal gasification. Most preliminary studies indicate that there is little chance that gas from coal can be produced for much under $1.00 or oil for much less than $4.25 per barrel but unfortunately the state of the art is such that it is doubtful that a good cost estimate can yet be made. While first installations might be running as early as 1976-77, it is doubtful that any meaningful quantities of gas from this source will be available much before 1980.

All of the substitute natural gas sources are heavily capital-oriented. When all aspects of each of these projects are taken into account, namely raw material and product transportation, plant facilities, etc. LNG, crude oil gasification, and coal gasification all come out approximately one million dollars of capital required per million cubic feet per day of capacity. This, of course, will vary 10%-20% plus or minus depending on the specific circumstances involved. It should be kept in mind that if inflation continues all of these costs will increase accordingly in the future and even after a facility has been built, there will undoubtedly be operating costs inflation or escalation which will cause the price to increase gradually over the operating life of the project.

On the whole, substitute natural gas could be, and hopefully will, in the future be an important source of supply of gas for the American economy. On the surface, it would appear that it is an extraordinary expensive supply but I would remind you that the exploration and development of gas reserves offers little relative economy. I cannot forget that exploration and development of
reserves of natural gas is a very risky business and that the average cost of finding and developing all such reserves is a misleading number. For example, I suspect that in the near future the average of exploring and developing large domestic gas reserves will average a minimum of 12¢ to 15¢ per MCF, which in itself amounts to a million dollars per million MCF per day for the development of a twenty to twenty-five year supply of natural gas.
THE DRILLING PROGRAM INDUSTRY - ITS STATUS AND ANALYSIS

By Robert C. Metzger, Resources Programs Institute, Inc.
551 Fifth Avenue, New York, New York 10017

Presented at the Ninth Annual Meeting of
The Society of Petroleum Evaluation Engineers
Houston, Texas, November 1971

My subject this afternoon is the status and analysis of the drilling program industry. I shall limit my discussion to the public sector of the industry, which refers to programs registered with the SEC. A significant portion of the industry conducts operations through non-registered vehicles where the number of investors is limited or certain other criterion are met whereby a public registration is not required.

The two topics of status of the industry and its analysis, are usually addressed independently, but they are quite inter-related. By this I mean that the status of the industry is becoming a function of the sophistication with which it is analyzed. That is to say, investors are becoming more aware of certain minimum standards they should expect of a company sponsoring drilling programs and, as a result, are becoming far more selective than they were in the late 1960's, when funds raised by publicly-offered drilling programs exceeded $400 million by the year 1969. The year 1970 witnessed a decline to $300 million, which is a rather remarkable sum considering the stockmarket fall and the discouraging results from perhaps the bulk of the money invested in the late 1960's, and it is indicative of the sheer momentum behind the need to shelter otherwise taxable dollars.

While investors were committing less in 1970, the number of programs filed for public offering, as well as the number of companies entering the field, increased obviously responding to the surge of interest in 1969. Among the newcomers were a number which came out of the woodwork, so to speak, with no evidence of any particular expertise in their field. I believe this proliferation of new programs, combined with often discouraging performance from companies of longer-standing reputation created an atmosphere of uncertainty in 1970 which has partially carried over into 1971. In short, I view the year 1970 as a correction period, wherein investors began to sit back and, perhaps for the first time for some, began to actually weigh what was being returned on their investment aside from certain initial tax benefits.

However, a favorable counter trend also began to develop in 1970 and it has definitely carried over into 1971, namely the emergence of a member of newcomers to the public drilling program field (though not newcomers to the petroleum industry) who appear to be demonstrating the ability to provide the investor an adequate return on his investment irrespective of the tax benefits.

I view 1971 also as a year of adjustment, but one wherein investors, having recognized pitfalls of the past, are feeling their way with cautious optimism to more promising opportunities. Overall, I expect companies to experience in 1971 a modest increase over the amount raised in 1970, and perhaps a resurgence of interest in 1972 of the type witnessed in 1969, however, on a much sounder basis.

What is it that investors should be looking for when seeking a suitable public program this year or next; or, simply, how should drilling programs be analyzed? First, I do not think programs should "rank", as advocated by so many people I speak to, simply because in actual practice I contend it is absolutely impractical to designate one program as number 3 and another as number 4. Aside from numerous quantitative inequities inherent in any ranking system, there are a number of considerations which cannot be quantified, among them being management integrity, special circumstances such as favorable contracts between a program and third parties, and the availability
of unusually attractive acreage to drill. I contend that programs should basically be viewed from a "go-no go" basis; that is, consider as acceptable any program which passes certain basic criteria and refine your choice on the basis of secondary considerations which are less critical to the overall success of the program.

What then are the important selection criteria? I place primary importance on management integrity and on managerial ability as evidenced by performance of past programs, especially performance within the last two years or so. Although financial success in prior programs does not insure success in the future, a sponsor who has demonstrated success, particularly consistent success over a number of years, is preferable to one who features programs which are reasonably-structured but has not as yet demonstrated an ability to find profitable quantities of oil and gas. A reasonable structure, with an equitable sharing of revenues between sponsor and participants, is implicit in adequate performance. However, I caution against preoccupation with program structure, particularly in view of certain generalizations concerning structure which seem to be in vogue lately and which are, at best, misleading and which can be detrimental to the investor's interests.

One concerns deductibility, or the amount of an investor's subscription which can be deducted currently for income tax purposes. I am aware of a tendency for investors to select only from among programs which offer them 100% deductibility; investors pay all costs which are currently deductible and the sponsor pays the costs which must be capitalized. I consider deductibility of secondary importance, provided the write-off under an alternative will be reasonable high. One reason is that the difference between a relatively high write-off (75% or more) and 100% is not substantial, and certainly not significant enough to determine which program should be selected. The penalty of lesser immediate deductibility is merely the present worth of obtaining the additional write-off now rather than in subsequent years, and would amount, for example, to roughly 3% of the amount subscribed for an investor in a 50% tax bracket, an 80% write-off and a discount rate of 7% over 10 years. A second factor to consider is that write-off is increased under the so-called capital non-capital program at the expense of inherent economic conflicts of interests which cannot arise under programs which make no distinction between types of costs investors and sponsor will bear. Among such conflicts: possibilities for substantial reduction of capital costs which the sponsor will bear by obtaining acreage via farmout rather than purchase (which is a common practice) and by leasing rather than buying well equipment (since leasing costs are deductible and therefore paid by investors, unless the program agreement provides otherwise).

Another popular generalization about program structure is that no provision for levying assessments on investors should be allowed, even if limited to a small percentage of the amount originally invested. Assessments are levied to finish activities which have been substantially completed or to further develop reserves which have been discovered during the primary phase of the program. Assessments are simply a protection of the investor's position in the event that additional activities cannot be fully financed by borrowing or other means; assessments proceeds typically involve low risk-high reward economics.

A third generalization on program structure is to select only from among programs which provide a redemption feature. However, provision for redeeming an investor's interest does not insure a timely repurchase will occur. More than half of the 100 odd programs in existence have provision for redeeming investor's interest, but only 15% have any form of firm commitment to do so. On the other hand, some form of buy-out eventually occurs for most programs, whether called for in the prospectus or not.

Turning to the question of evaluating the performance which I have identified as being so important, I refer to the prior activities section of the prospectus, which examines the performance of past programs by the offeror. This section is essentially divided into three sections: one which reveals through well counts the type of activity, exploratory or development, in which
the prior programs have engaged; another which summarized the total expenditures and gross revenue to-date for investor and for program management; and, a third section summarizing total cash contributions and net cash or receipts to-date for investors and for management. Data over the last calendar quarter prior to the date of the financial data is also provided, and is useful in indicating the current trend of the data. The two principal shortcomings of these disclosures, in my opinion, are (1) insufficient information on cash actually distributed to the investor, as opposed to amounts merely credited to his account but not actually returned to him, and (2) the frequent lack of data concerning amounts borrowed on behalf of investors and the amount of future income dedicated to repaying such borrowing.

Aside from data in the prospectus, the only additional source of publicly-available data of which I am aware is a subscription service called PROFILE, which my firm prepares, where data on past programs is traced (from past prospectuses) back to inception of each prior program. This data, presented graphically in terms of cash returned as a percentage of cash invested, adds the important dimension of a trend line to the data available to investors in the most recent prospectus. In the appendix attached, "Profile on Woods Corporation", you will note that certain conclusions can be drawn by referring to the Investor Financial Summary and the payout graph. The 1964 program (circular symbol on the graph) is satisfactory, having paid out in about 6½ years; the 1967 program (diamond symbol) is excellent, with about a 3-year payout. Neither of these programs require any particular further examination. However, the trend line of the 1965 program (upright triangular symbol) indicates this program will not be satisfactory, and this conclusion is verified by referring in the table above the graph to the cash flow to investors over the last calendar quarter (3rd column from the right-hand side); the last 3 month data annualized suggests a future cash flow of only 3 to 4% per year. The 1966 program (square symbol) is not as clear-cut, but referring again to cash flow over the last quarter suggests pay-out may occur in about 6 more years.

An additional useful piece of information which is to determine the amount of compensation management is receiving and what portion of the capital management is contributing relative to the investor. Reference to the Management Financial Summary indicates Woods has been contributing 25% of total capital in the earlier stages of their programs (for example, the 1970 programs) with the percentage increasing with age of the program (for example, 1966 and 1967 programs) to roughly 40% revenues are shared 50-50 with the investor.

So much for publicly-available data. For a complete evaluation, reserve data for each program, which is often treated as confidential information by program sponsors, is required. Gaining access to such information is often difficult and will depend basically on (a) the potential value to the Sponsor to release such data and (b) the status of the recipient. A prospective investor, for example, should be denied a request for the data, since it is a violation of the Securities Act of 1933 to employ future reserves discovered by past programs to induce an investor to participate in a current program. Ideally, such data should be obtained and combined with historical financial information to derive a discounted cash flow rate of return for each program.

In summary, it is basically this kind of financial evaluation which I feel is required to properly evaluate the advisability of investing with a drilling program sponsor. Together with a judgment of management integrity, I consider it the primary consideration in the selection process. Deductibility, redemption features, and special circumstances should influence the selection from among those programs with satisfactory prior performance, but usually should not be deciding factors in the absence of demonstrated results. Finally, I should add that in general, I do not recommend analyzing drilling programs by examining the specific prospects intended for drilling. In effect, this approach attempts to second-guess the technical ability of the oil company staff. Aside from the advisability of second-guessing a staff with demonstrated tract record, one must have access to a number of geologists, each an expert in his particular area of the country, for the exercise to be of value. Also, in contrast to
most private programs where prospects to be drilled are specifically designated beforehand, any prospect analyzed in connection with a public program may not end up being drilled.

I believe investors are beginning to think about the kinds of considerations I have covered here today, though in general I suspect they are not as yet demanding the answers. At the same time I am aware of a growing number of companies which are recognizing the need and desirability of such scrutiny, and I feel most of these companies will stand the test by the time investors become more knowledgeable before investing.
**PROFILE — A Continuing Study of Oil and Gas Programs**

<table>
<thead>
<tr>
<th>Sponsor</th>
<th>WOODS PETROLEUM CORPORATION</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4900 North Sante Fe</td>
</tr>
<tr>
<td></td>
<td>Oklahoma City, Oklahoma 73118</td>
</tr>
<tr>
<td></td>
<td>(405) 528-7531</td>
</tr>
<tr>
<td>Program</td>
<td>Woods Seventy Drilling Venture</td>
</tr>
<tr>
<td>Form</td>
<td>Limited Partnership</td>
</tr>
<tr>
<td>Prospectus</td>
<td>June 1, 1971 Supplement (Filed Mar. 31, 1970; File No. 2-36920)</td>
</tr>
<tr>
<td>Offering</td>
<td>Part of an original $12,000,000 offering is a series of one to four partnerships per year through Dec. 1, 1972; minimum of $1,000,000 required by Aug. 1, 1971 to initiate next partnership.</td>
</tr>
<tr>
<td>Offer Closes</td>
<td>Not specified</td>
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<tr>
<td>Minimum Participation</td>
<td>$10,000, with additional increments available in multiples of $5,000, allocated to the next partnership and payable 1/3 when $1,000,000 minimum is obtained and additional 1/3 payments 30 days and 60 days thereafter.</td>
</tr>
<tr>
<td>Assessments</td>
<td>Optional and unlimited. Failure to participate results in Sponsor's bearing non-participant's costs and recovering 300% of such costs from non-participant's interest in the property concerned, after which interest reverts to non-participant.</td>
</tr>
<tr>
<td>Proposed Activities</td>
<td>Approximately 65% exploratory and 35% development drilling in the U.S. and Southern Canada.</td>
</tr>
<tr>
<td>Offered By</td>
<td>a. Sponsor</td>
</tr>
<tr>
<td></td>
<td>b. NASD members</td>
</tr>
<tr>
<td>Sales Commission</td>
<td>6% of subscriptions to NASD members and none to Sponsor, paid by Sponsor.</td>
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<tr>
<td>Investor Costs</td>
<td>See Mgt. Compensation, item a.</td>
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<tr>
<td>Front-End Charges</td>
<td>a. All non-capital costs</td>
</tr>
<tr>
<td></td>
<td>b. 50% of operating costs.</td>
</tr>
<tr>
<td>Other</td>
<td>c. Allocated overhead, including salaries, limited to 2% of non-capital costs.</td>
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<tr>
<td></td>
<td>d. See Mgt. Compensation, item c.</td>
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<tr>
<td>Investor Receipts</td>
<td>50% of receipts</td>
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<tr>
<td>Management Costs</td>
<td>a. Sales commission</td>
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<td></td>
<td>b. Offering costs</td>
</tr>
<tr>
<td></td>
<td>c. All capital costs and cost of leasing equipment</td>
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<tr>
<td></td>
<td>d. 50% of operating costs.</td>
</tr>
<tr>
<td>Mgt. Compensation</td>
<td>a. 5% of non-capital costs</td>
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<td></td>
<td>b. 50% of receipts</td>
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<td>c. Monthly well charges</td>
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<tr>
<td>Deductibility</td>
<td>100% (RPI estimate)</td>
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<tr>
<td>Redemption</td>
<td>None</td>
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</table>
| Summary                   | **Investor:** Pays all non-capital costs and receives 50% of receipts.  
**Management:** Pays all capital costs and receives 50% of receipts. |

*Resource Programs Inc.*

RESEARCH AND ADVISORY FIRM OF
### PRIOR ACTIVITIES

#### Management Financial Summary

**Data Through Dec. 31, 1970**

<table>
<thead>
<tr>
<th>Program</th>
<th>CASH PAID IN</th>
<th>Total Expend.</th>
<th>RECEIPTS</th>
<th>Unrecovered Cash</th>
<th>Cash Recovered</th>
<th>CASH DISTRIBUTED</th>
<th>PAYOUT</th>
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<tr>
<td></td>
<td>Thousands</td>
<td>Dollars</td>
<td>Total</td>
<td>Last 3 Mo.</td>
<td></td>
<td>Total</td>
<td></td>
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<tr>
<td>1964(a)</td>
<td>$927</td>
<td>$1,148</td>
<td>$1,506</td>
<td>$56.5</td>
<td>$358(lb)</td>
<td>$1,285</td>
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<tr>
<td>1965</td>
<td>808</td>
<td>934</td>
<td>828</td>
<td>24.0</td>
<td>106</td>
<td>702</td>
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<td>1966</td>
<td>2,065</td>
<td>2,357</td>
<td>2,274</td>
<td>90.0</td>
<td>83</td>
<td>1,982</td>
<td>1,982</td>
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<td>1967</td>
<td>2,242</td>
<td>2,619</td>
<td>4,235</td>
<td>303.4</td>
<td>(1,616(lb))</td>
<td>3,858</td>
<td>3,858</td>
</tr>
<tr>
<td>1968</td>
<td>2,443</td>
<td>2,594</td>
<td>970</td>
<td>131.9</td>
<td>1,624</td>
<td>819</td>
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<tr>
<td>1969</td>
<td>2,143</td>
<td>2,223</td>
<td>686</td>
<td>231.1</td>
<td>1,537</td>
<td>606</td>
<td>606</td>
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<tr>
<td>1969 Canadian</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>1970 A-1</td>
<td>211</td>
<td>211</td>
<td>--</td>
<td>--</td>
<td>211</td>
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<td>1970 A-2</td>
<td>756</td>
<td>758</td>
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<tr>
<td>1970 Seventy</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>1970 Seventy</td>
<td>388</td>
<td>388</td>
<td>--</td>
<td>--</td>
<td>388</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>1970 Seventy</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(a) Private program  
(b) All expenditures plus amounts in parentheses have been recovered.  
(c) Data is net cash credited to investor's account, which may not equal the amount actually distributed.

---

### Definitions

**AMOUNT SUBSCRIBED**

Amount originally contributed by investors in the program.

**CASH PAID IN**

Amount subscribed plus assessments (for Investor Financial Summary) or cash contributed by management (for Management Financial Summary). Any assessments for operating costs are excluded.

**EXPENDITURES**

Amounts charged to investors or to management for all activities of the program, including operating costs.

**RECEIPTS**

Revenue from sales of oil and gas, and receipts from other sources credited to investors or to management, after deduction of production taxes and existing lease burdens, and before deduction of operating costs.

**UNRECOVERED CASH**

Total Receipts less total Expenditures, representing cash remaining to be recovered.

**CASH RECOVERED**

Cash available for return to investors or to management, equal to the difference between Cash Paid In and Unrecovered Cash.

**CASH DISTRIBUTED**

Cash Recovered which has actually been distributed to investors or to management.

**PAYOUT**

(Cash Distributed)/(Cash Paid In), expressed as a percent, or (Cash Recovered)/(Cash Paid In) if Cash Distributed is not available.

**DEDUCTIBILITY**

Percent of Cash Paid In during the first year of program operations which investors may expense for U.S. income tax purposes.
### Investor Financial Summary

Data Through Dec. 31, 1970

<table>
<thead>
<tr>
<th>Program</th>
<th>Amount Subscribed</th>
<th>CASH PAID IN</th>
<th>Total Expend.</th>
<th>RECEIPTS Total Last 3 Mos.</th>
<th>Unrecovered Cash</th>
<th>Cash Recovered</th>
<th>CASH DISTRIBUTION Total Last 3 Mos.</th>
<th>Percent PAYOUT Deductibility</th>
</tr>
</thead>
<tbody>
<tr>
<td>1964(a)</td>
<td>$850</td>
<td>$1,324</td>
<td>$1,545</td>
<td>$1,506</td>
<td>$56.5</td>
<td>$39</td>
<td>$1,285</td>
<td>97% 100%</td>
</tr>
<tr>
<td>1965</td>
<td>1,400</td>
<td>2,086</td>
<td>2,212</td>
<td>828</td>
<td>24.0</td>
<td>1,384</td>
<td>702</td>
<td>34 100</td>
</tr>
<tr>
<td>1966</td>
<td>1,567</td>
<td>3,672</td>
<td>3,964</td>
<td>2,274</td>
<td>90.0</td>
<td>1,690</td>
<td>1,982</td>
<td>54 100</td>
</tr>
<tr>
<td>1967</td>
<td>2,000</td>
<td>4,145</td>
<td>4,522</td>
<td>4,235</td>
<td>303.4</td>
<td>287</td>
<td>3,858</td>
<td>93 100</td>
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<tr>
<td>1968</td>
<td>3,500</td>
<td>6,418</td>
<td>6,569</td>
<td>970</td>
<td>131.9</td>
<td>5,599</td>
<td>819</td>
<td>13 100</td>
</tr>
<tr>
<td>1969</td>
<td>5,500</td>
<td>7,716</td>
<td>7,796</td>
<td>686</td>
<td>231.1</td>
<td>7,110</td>
<td>606</td>
<td>8 100</td>
</tr>
<tr>
<td>Canadian</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1970</td>
<td>2,150</td>
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<td>2,238</td>
<td>4</td>
<td>3.0</td>
<td>2,234</td>
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<tr>
<td>Seventy A-1</td>
<td>1,320</td>
<td>1,186</td>
<td>1,186</td>
<td>4</td>
<td>4</td>
<td>1,186</td>
<td>2</td>
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<tr>
<td>Seventy A-2</td>
<td>1,550</td>
<td>1,550</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(a) Private program
(b) Data is net cash credited to investor's account, which may not equal the amount actually distributed.
(c) As of Feb. 1, 1971

### Investor Payout, Pre-Tax

![Graph showing the payout of the programs from 1964 to 1973](image)

**Note:** Decrease due to additional development costs.

---

Resource Programs Inc.

RESEARCH AND ADVISORY FIRM OF
Background of Company

Woods Petroleum Corporation was organized in 1954 and has conducted drilling ventures since 1958. It conducted its first publicly-offered program in 1965 and all programs since that time have been based on the capital/non-capital arrangement which is utilized in the current offering.

Woods Petroleum of Canada, Ltd. was formed in 1969 to conduct operations in Canada and is a wholly-owned subsidiary of Woods Petroleum Corporation. Woods Petroleum Corporation in turn is wholly-owned by Woods Industries, Inc., one of the largest motor carriers of automobiles in the United States. Substantially all of Woods Industries is owned by Woods Corporation, which also owns Star Manufacturing Company, a major manufacturer of pre-engineered steel buildings. The common stock of Woods Corporation is listed on the New York Stock Exchange.

Management

The following are the directors and executive officers of Woods Petroleum Corporation:

Roy G. Woods  
A. D. Freshour  
V. Lee Powell  
Herb Mee, Jr.  
James T. Van Norden  
Leroy Usery  
Chairman of the Board  
President and Director  
Vice President  
Vice President, Treasurer and Director  
Vice President  
Secretary and Chief Accountant

All of the executive officers of Woods Petroleum Corporation (Woods) have been actively engaged in conducting the operations of Woods and Woods Industries, Inc. as their principal business occupation for more than the past five years, except Mr. Powell and Mr. Van Norden. Mr. Powell was Assistant to the President of An-Son Corporation from 1965 until joining Woods in 1966. Prior to that time he had been an engineer for Amex Petroleum Corporation for approximately one year and was Vice President of Ramsey Engineering Incorporated from 1961 to 1964. Mr. Van Norden was president of Wyott Corp. from 1962 to 1966. In 1967, he was an independent financial consultant, and from 1968 until joining Woods in 1970, he was vice president of Denver Corp.

Mr. Freshour has directed Woods' oil and gas activities since the mid-1950's and, together with Messrs. Woods and Mee, he is primarily responsible for the formulation of the Company's oil and gas policy.
WHAT THE OIL INDUSTRY NEEDS NOW

By H. J. Gruy, President, H. J. Gruy & Associates, Inc.
Dallas, Texas

Presented at the Tenth Annual Meeting of
The Society of Petroleum Evaluation Engineers
Dallas, Texas, December 1972

Our country runs on oil and gas. Oil furnishes just under half and gas a third of the total energy we consume, a total of 78% between them. With the shortage of gas becoming rapidly more acute, oil becomes more vital as the cheapest substitute in terms of dollars, pollution and ecology.

With rapidly increasing costs of exploration for oil and gas as deeper, more expensive wells are required and as the search moves to deeper waters and more remote areas, the need to recover a larger percentage of the oil that has already been found becomes more evident.

Already located reservoirs in Texas hold some 145 billion barrels of oil at discovery. Only 33 billion barrels of this have been produced. Another 13 billion barrels remain recoverable under existing conditions leaving a staggering 99 billion barrels available for additional recovery attempts.

More secondary recovery and even exotic tertiary methods will come into play as our need for oil becomes more acute. However, these operations are expensive and entail a certain degree of risk. The risk of course is greater in the untried tertiary methods. To be successful, all of these methods require control of the entire reservoir by the operator of the project, since they are based on the ability to move oil through the rocks away from injection wells and toward producing wells. If the entire reservoir is not controlled by the operator, competitors may operate in a manner which would cause failure of the project or drain off the oil to their own wells.

Much of the unrecovered oil in Texas that is subject to recovery attempts by these secondary and tertiary methods is in large reservoirs that have many owners. Thousands of individual and corporate entities are involved. Under present laws, the time and costs involved in voluntary unitization are simply prohibitive. In the first place, it is almost impossible to get people, many of who are completely without knowledge of the factors involved, to agree on participation factors. Unfortunately, there are always a few in any large group who will realize the nuisance value of holding out, particularly if their interest is small and they do not have much to lose. By holding out, they can be important and exact a high toll for their concurrence.

Unitization of the easy fields has been done. Most of those that remain to be unitized represent such an insurmountable problem under existing rules that there is not enough incentive to try.

Compulsory unitization laws are in effect in most states with considerable amount of production, except Texas. These laws have been successful and have encourage unitization with its contribution to additional oil recovery. Figure 1 shows the greater number of reservoir-wide units formed in Louisiana, which has such a law, as compared to Texas, which does not. Figure 2 shows the declining number of secondary recovery units formed in Texas with the resultant decline in anticipated recovery.

Additional oil recovery is important to every person in the State of Texas whether he owns oil production or not. Severance taxes on oil and gas production and other oil industry taxes contributed $339.2 million to the State in 1971, while ad valorem taxes on oil producing properties contributed $20.2 million to the counties, school and hospital districts and other local taxing authorities. This was well
over half (58.5 percent) of the total taxes paid by business in the State of Texas. A decline in production would reduce this revenue and it would have to be replaced by sales taxes or other levies on the people. A statutory unitization law would greatly aid in maintaining the State's oil producing capacity.

Oil is also important politically to us as a nation. Oil that we buy abroad uses up dollars and adversely affects our balance of payments. The amount of foreign oil which we imported increased from 12.2 percent of domestic demand in 1952 to 24.9 percent in 1971. Our ability to produce is declining and our usage is increasing. If ever this gap between our requirements and our own production gets so large that we must go to unfriendly-held sources to fill our needs, we, that day, cease to be independent people. The mere closing of the valve on any pretext will stop our cars and trucks and electric generation plants, ground our airplanes and shut down our factories. Our food will rot in the fields and spoil in the warehouses. We will be forced to agree to any terms the foreign owners wish to extract from us.

It is too late for petty bickering. We must pass laws to enable this oil to be recovered.

Of course it takes more than favorable legislation to get oil produced. It takes money. What will or will not be done to find and recover oil depends on economics.

Industry economics has changed drastically over the thirty-seven years since I started as a summer worker in the oil fields by my statistics haven't been gathered that far back - just over the last 15 years.

Let us look at crude oil production:
1956 -- 7.151 million bbls/day
1971 -- 9.535 million bbls/day
add condensate and natural gas liquids
1956 -- 0.801 million bbls/day
1971 -- 1.700 million bbls/day
add net imports for total domestic demand
1956 -- 9.4 million bbls/day
1971 -- 15.1 million bbls/day

This is a sizeable increase. Note that imports went from 14.2% in 1956 to 24.9% in 1971, while demand was going from 9.4 to 15.1 million bbls/day and the actual quantities of imports more than doubled. What were we doing to find more oil?

The only way to find oil is to drill holes. Geology or geophysics does not find oil - unless holes are drilled. How many were being drilled and how successful was the effort?

In 1956, 30,730 oil wells were completed. In 1971, 11,380 oil wells were completed. If you take all the dry holes and expendable wells and divide them between oil and gas on the same ratio as oil completions had to gas completions you end up as follows:

<table>
<thead>
<tr>
<th>Year</th>
<th>Producers</th>
<th>Others</th>
<th>Drilled for Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>1956</td>
<td>30,730</td>
<td>19,935</td>
<td>50,665</td>
</tr>
<tr>
<td>1971</td>
<td>11,380</td>
<td>8,072</td>
<td>19,952</td>
</tr>
</tbody>
</table>

Less than forty percent as many wells were drilled for oil in 1971.

Well, what was the result of the drilling; Reserves Added Per Well

<table>
<thead>
<tr>
<th>Year</th>
<th>Crude Oil Reserves Added</th>
<th>Crude Oil Oil Drilled</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(Barrels)</td>
<td>(Barrels)</td>
</tr>
<tr>
<td>1956</td>
<td>2,974Mmbbls</td>
<td>96,800</td>
</tr>
<tr>
<td>1971</td>
<td>2,318Mmbbls</td>
<td>195,100</td>
</tr>
</tbody>
</table>

So, we were doing better per well drilled but not drilling enough wells.

What was happening in natural gas?

<table>
<thead>
<tr>
<th>Year</th>
<th>Usage (Tcf/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1956</td>
<td>10.064</td>
</tr>
<tr>
<td>1971</td>
<td>22.800</td>
</tr>
</tbody>
</table>

Usage had more than doubled.

Wells drilled for gas have not declined as much:

<table>
<thead>
<tr>
<th>Year</th>
<th>Gas Producers</th>
<th>Others</th>
<th>Drilled for Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>1956</td>
<td>4,543</td>
<td>2,952</td>
<td>7,495</td>
</tr>
<tr>
<td>1971</td>
<td>3,915</td>
<td>3,967</td>
<td>7,882</td>
</tr>
</tbody>
</table>
Gas reserves added were:

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Gas Reserves Added (Tcf)</th>
<th>Gas Producers Drilled for Gas (Bcf)</th>
<th>Total Gas (Bcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1956</td>
<td>24.72</td>
<td>5.44</td>
<td>3.30</td>
</tr>
<tr>
<td>1957</td>
<td>20.01</td>
<td>4.33</td>
<td>2.61</td>
</tr>
<tr>
<td>1958</td>
<td>18.90</td>
<td>3.94</td>
<td>2.31</td>
</tr>
<tr>
<td>1959</td>
<td>20.62</td>
<td>4.10</td>
<td>2.44</td>
</tr>
<tr>
<td>1960</td>
<td>13.89</td>
<td>2.64</td>
<td>1.49</td>
</tr>
<tr>
<td>1961</td>
<td>17.17</td>
<td>3.03</td>
<td>1.73</td>
</tr>
<tr>
<td>1962</td>
<td>19.48</td>
<td>3.33</td>
<td>1.95</td>
</tr>
<tr>
<td>1963</td>
<td>18.16</td>
<td>3.82</td>
<td>2.19</td>
</tr>
<tr>
<td>1964</td>
<td>20.25</td>
<td>4.17</td>
<td>2.35</td>
</tr>
<tr>
<td>1965</td>
<td>21.32</td>
<td>4.51</td>
<td>2.56</td>
</tr>
<tr>
<td>1966</td>
<td>20.22</td>
<td>4.62</td>
<td>2.51</td>
</tr>
<tr>
<td>1967</td>
<td>21.80</td>
<td>5.96</td>
<td>3.31</td>
</tr>
<tr>
<td>1968</td>
<td>13.70</td>
<td>3.96</td>
<td>2.14</td>
</tr>
<tr>
<td>1969</td>
<td>8.38</td>
<td>2.05</td>
<td>1.11</td>
</tr>
<tr>
<td>1970</td>
<td>11.19</td>
<td>2.91</td>
<td>1.67</td>
</tr>
<tr>
<td>1971</td>
<td>9.83</td>
<td>2.51</td>
<td>1.25</td>
</tr>
</tbody>
</table>

We are still finding gas but not near the rate at which we are using it. Actually, it is necessary to find more each year than is being used (if the market is growing) because, for a larger rate of production, a larger reserve is required for sustained delivery capacity.

Now comes economics and financing. Why aren't the required number of wells being drilled? Because the profitability is not there. The incentive is not there. As shown on the attached Figure 3 and Table 1, the price of oil in constant dollars is below the average of the last eighty years. You will note that the price of oil was subject to wide swings before 1931 and was stable thereafter. The price was stabilized by market demand proration in 1931. Note that it was stabilized but not as a high value. Prior swings were due to the nature of oil. When new fields were discovered and production was in excess of market demand, the price dropped drastically because there was nothing to do with the oil. Then, with oil so cheap that additional drilling could not be profitable, the search for oil stopped. The supply became short. The price shot up. New exploration was successful and the cycle was repeated. Boom and bust! This could support no research effort, no seismic programs -- no schools for petroleum engineers. All of these things require a stable industry. Water is not produced in excess of market demand. Electricity is not produced in excess of market demand. Cars are not produced in excess of market demand. Yet, the liberal politicians are screaming for wide-open oil production. They want cheap oil. They don't realize how fast the price will go up.

The price of oil has been held down by politics and foreign competition. The price of gas has been held down by federal order.

Gas, a superior and much-desired fuel, is easily regulated, requires no on-location storage space or tanks, produces no ashes or clinkers to haul off and dispose of and has no smoke or fumes. On a BTU basis, gas sells for one-third the cost of coal or fuel oil. This greatly increased the demand while discouraging supply.

One of the best looks at the economics of the oil and gas industries is a paper, entitled "Oil and Gas - Two Industries in One" by John D. Emerson and Harold D. Hammar of the Chase Manhattan Bank, which was delivered at the Symposium of Petroleum Econ and Valuation given by the SPE in March 1971 in Dallas. The authors divided the expenses of the search for oil and gas arbitrarily in the same manner as I have divided the dry holes. They took all the money that was spent and all of the reserves that were found over the last 10 years. Taking the drilling costs and producing expenses over the usual period required for depletion and using current average prices of oil and gas, they found that every dollar invested in the oil industry over the last 10 years will ultimately return (before taxes and before discount to present worth for the time value of money) $1.77. Hardly a handsome return, especially considering the risks involved and the alternate investment opportunities.

On the other hand, every $1.00 invested in the gas business will ultimately return only $0.83 on the same basis. Is there any wonder that people are not rushing into the gas business?

Back before World War II, oil companies that were successful generated enough profit to do their exploration and drilling. Today, this is impossible. The companies have a cash deficit. They show profits because they capitalize much of their cost.
and charge it off over future years. This is on the assumption that the production comes out over the future years so the cost of facilities should come out in the future also. But each year requires deeper, more expensive wells, bigger platforms, deeper water, more remote transportation, and greater costs.

Let us look at the Chase Bank Group of oil companies (so-called because Chase has been reporting on their source and disposition of funds as a group for many years). It started out as the 30 largest oil companies and was decreased through mergers and increased by addition until it is now 28. These companies account for about three-fourths of all crude oil produced in the free world.

Their main source of funds is still net income, which must grow at a rate equal to or greater than market expansion and the related need for new spending. That has not happened!! In 1969 and 1970 with a market growth of 18 percent, net income actually declined. Let's compare the spread over the last decade:

<table>
<thead>
<tr>
<th>Year</th>
<th>Domestic Demand</th>
<th>Net Income</th>
<th>Taxes</th>
</tr>
</thead>
<tbody>
<tr>
<td>1960</td>
<td>9,991 1000 b/d</td>
<td>$3.5 billion</td>
<td>$2.8 billion</td>
</tr>
<tr>
<td>1970</td>
<td>14,716 1000 b/d</td>
<td>6.4 billion</td>
<td>9.8 billion</td>
</tr>
</tbody>
</table>

In the last two years, while net income declined slightly, taxes increased 40 percent. Let's look at net income as related to total revenue.

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Income</th>
<th>Net Income</th>
<th>Percent of Total Income</th>
</tr>
</thead>
<tbody>
<tr>
<td>1960</td>
<td>$38 billion</td>
<td>$3.5 billion</td>
<td>8.8%</td>
</tr>
<tr>
<td>1968</td>
<td>70 billion</td>
<td>6.5 billion</td>
<td>9.4%</td>
</tr>
<tr>
<td>1970</td>
<td>82 billion</td>
<td>6.4 billion</td>
<td>7.8%</td>
</tr>
</tbody>
</table>

Let's look at cash earnings as compared to total financial needs. They would have needed more if they had kept up the drilling pace of the 1950's.

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Need</th>
<th>Cash Earned</th>
</tr>
</thead>
<tbody>
<tr>
<td>1960</td>
<td>$9 billion</td>
<td>$7.5 billion</td>
</tr>
<tr>
<td>1970</td>
<td>19 billion</td>
<td>13.4 billion</td>
</tr>
</tbody>
</table>

Of the total funds used in 1970, net income was 35.1 percent, depreciation and depletion were 34.4 percent, and 2.8 percent was from miscellaneous sources. This gives only 72.3 percent of the needed money from internal sources.

Where does the differences come from? There are only two sources, (i) borrowing and (ii) selling part of the business.

Borrowing - How do you do it? From bank loans and by selling bonds.

Selling interests can be done by:

1. Issuing more stock and so reducing the current owner's interest in the company.
2. Selling some properties such as producing wells, refineries, or marketing facilities.
3. Selling interests in future findings through a drilling fund.

These questions arise:

As to borrowing: If they are not generating enough money now, how do they expect to have enough in the future when part has to go to repay loans?

As to selling stock: Oil companies earn less than other types of businesses:

<table>
<thead>
<tr>
<th>Year</th>
<th>United States Oil Company Return on Invested Capital in the (Percent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1960</td>
<td>11.2</td>
</tr>
<tr>
<td>1968</td>
<td>12.7</td>
</tr>
<tr>
<td>1969</td>
<td>10.9</td>
</tr>
<tr>
<td>1970</td>
<td>9.9</td>
</tr>
</tbody>
</table>

That oil and gas industry earnings are not great enough to attract the necessary capital to the industry is shown by the huge investments in city real estate developments now being made by both oil and gas companies while their main business is capital starved. You can do better in a less risky business. Why should an investor buy oil stock?

How about selling properties? The
buyer must make a profit and the seller must pay a tax on the income from the sale. So again, a short-term advantage means less net in the long pull.

The only answer to this dilemma is higher prices for oil and gas, lower taxes on oil and gas, or a combination.

Special tax advantages in the past were used to give the public cheap energy in the interest of progress and prosperity. Reducing these tax incentives has to be reflected in higher prices.

The argument against higher prices is that we should import more cheap oil. It sounds good to the uninformed but there are perils. First, the price isn't going to stay cheap if we need the oil. Second, if we ever let the gap between what we need and what we produce get so big that it cannot be filled by "independent" sources, we become dependent on energy supplied by our enemies. We then become a conquered people without a military defeat. Without energy, we cannot operate our economy. We cannot feed our people. We are at the mercy of those who control it.
UNITED STATES PRICES OF CRUDE OIL
1890 - 1967

(Deflated Prices in Constant 1954 Dollars)

CRUDE OIL PRICE

78 Year Average 2.51
## UNITED STATES CRUDE OIL MARKET PRICES AND DEFLATED PRICES
1890 - 1967

<table>
<thead>
<tr>
<th></th>
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The Society of Petroleum Evaluation Engineers  
Dallas, Texas, December 1972

SUBSTITUTE NATURAL GAS AND THE ENERGY CRISIS

By  
Anton Roeger, III  
Senior Engineer  
Texas Eastern Transmission Corporation  
Shreveport, Louisiana

ABSTRACT

This paper briefly reviews the historical energy consumption pattern and future energy supply picture for the United States. The outlook for conventional natural gas production is gloomy unless more incentives are provided. The anticipated supply shortfall is being supplemented on a short-term basis by imported liquefied natural gas and substitute natural gas from naphtha gasification. Long-term solutions are pipeline gas from Alaska and Canada, imported liquefied natural gas, and substitute natural gas from coal gasification. Environmental analysis considerations for substitute natural gas plants are extensive and complex.

† † †

The explosive growth in energy consumption of the past century and a half has been led by fossil fuels which are not renewable on any time scale meaningful to man (Figure 1). Coal’s share of the United States energy input has declined sharply since 1945 while both natural gas and petroleum have increased their share due largely to imports. About one-third of the United States’ energy is supplied by natural gas. The only renewable source of energy that now makes any significant contribution to the United States’ economy is hydropower which supplies about four percent of the energy input.

Despite the great production of energy, the United States has sufficient quantities of non-renewable fuels—petroleum, natural gas, coal, oil shale, tar sands and uranium resources—to supply all of the nation’s growing energy requirements and to remain largely self-sufficient in energy for as far into the future as
we can foresee. One interesting projection (Figure 2) has been developed by Dr. Earl Cook of Texas A & M University who sees the future use of energy divisible into three phases, each dominated by a particular type of energy constraint:

—Mining Phase which will last another few decades for petroleum and natural gas; a century for oil shales, tar sands, and fissile uranium; a few centuries for coal. Resource availability is the dominant constraint.

—Rock-Burning Phase which will last a few hundred years. The dominant technology is that of the breeder reactor, the primary fuels are fertile uranium and thorium. The dominant constraint is environmental quality, principally waste management limits.

—Solar Phase which will last until man or the sun fades out. If fusion power enters this scheme, it will fall into the first phase if it requires lithium, into the second phase if only deuterium.

Before the United States gradually shifts from petroleum and natural gas to tar sands, oil shale and a nuclear-based fuel economy, projections are for continued steady increases in petroleum and natural gas imports because these sources are relatively cheaper and more abundant. Conversion of tar sands and oil shale will very likely follow coal conversion in the sequence of synthetic fuel development without some new technology to overcome the immense capital requirements and low recoveries of oil and without higher crude oil prices.

The United States can remain largely self-sufficient in energy resources provided it chooses to do so and follows policies designed to achieve that objective. The development of the primary fuels is very closely related to factors (Table 1) such as resource base, government pricing, taxation, licensing and leasing policies, international politics, technology and environmental impact considerations.

The nation faces the prospect of serious and costly shortages of energy in the near future, as is now the case with natural gas, because some of these factors have discouraged investments to develop new energy supplies.

<table>
<thead>
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<th>TABLE 1 — Factors Limiting Energy Supply</th>
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<td>LABOR SUPPLY AND PRODUCTIVITY</td>
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OUTLOOK FOR NATURAL GAS PRODUCTION

The American Gas Association reports that 1971 was the fourth consecutive year that proved reserves have fallen in the lower 48 states. The additions to proved gas reserves have fallen short of the annual production and the industry is having difficulty meeting market demands as evidenced by curtailment programs.

A number of factors have been responsible for this energy crisis. Artificially low pricing of natural gas as established by the Federal Power Commission has resulted in decreased drilling efforts and stimulated consumption of natural gas relative to other competing fuels. Additional demands upon natural gas as a pollution-free fuel have also contributed to this energy crisis.

The number of new producing wells has fallen far short of depleted and abandoned wells. Domestic operators completed only 60 percent of the number of development and wildcat wells in 1971 compared with 1962 (Figure 3). Some improvement is expected over the 1971 level due primarily to improved money-raising records of public drilling funds and gas utility advance payments for exploration.

The gas supply for the lower 48 is not expected to increase measurably for the foreseeable future (Figure 4). Natural gas production will gradually fall off from about 24 trillion cubic feet in 1972 to 19 trillion by 1980. The demand is projected to increase steadily throughout this period.

SOLUTIONS TO INCREASE NATURAL GAS SUPPLY

One solution to the natural gas supply shortfall is to discover and develop potential gas reserves. To accomplish this, the current low level of geophysical work and exploratory drilling will have to be drastically increased. The Federal Power Commission announced in August it will ease price controls over any sales of newly discovered natural gas to interstate pipelines, in a move aimed at spurring domestic exploration in the face of a growing natural gas shortage.

The second possible solution to the natural gas supply shortfall is to utilize supplemental gas supplies (Figure 4). Pipeline gas from Canada, Mexico, and Alaska, imported liquefied natural gas (LNG) and substitute natural gas (SNG) from various petroleum fractions, and coal will play an
important part in meeting the projected supply shortfall. Even if all available supplemental sources were tapped, the gap between supply and demand will begin to widen rapidly after 1973 and is expected to exceed ten trillion cubic feet per year by 1980. The deficiency is expected to grow even more in later years.

Current cost estimates for base load supplies from supplemental sources range from 60 cents to 140 cents per thousand cubic feet at the point of production or delivery, and are expected to increase by the time these sources achieve full commercial development. These costs compare with an average wellhead price of 25 cents per thousand cubic feet and recent intrastate sales of close to 50 cents per thousand cubic feet.

PIPELINE GAS FROM ALASKA AND CANADA

Conventional natural gas has been discovered on Alaska’s North Slope, in the Canadian Arctic, and in Eastern Canada. Such established and potential gas reserves must be considered as supplemental gas supplies in spite of their remoteness and the high cost of delivering them to the United States. Pipeline gas supply falls into the long-term solution because of the lead times required for construction of equipment and facilities.

One project being studied by two consortiums of United States and Canadian firms involves construction of a 48-inch diameter, five billion dollar pipeline from Alaska’s North Slope and the Canadian Arctic to the United States through Canada to transport about 3.5 billion cubic feet per day. The estimated cost of transportation is about one dollar per thousand cubic feet.

LIQUEFIED NATURAL GAS

In October 1964, the world’s first commercial shipment of liquefied natural gas (LNG) arrived in England from Algeria. Advances in technology have increased the ease of handling and transporting the gas from remote producing regions to populous markets. Recent discoveries have provided substantial reserves to support the relatively large capital investments in facilities to handle an expanding business.

Spot purchases of excess LNG from existing operation plants in Algeria and Libya are one possibility of obtaining a supplemental supply of gas within a short time period of a few years. Texas Eastern Transmission Corporation has recently been given authority to import two shiploads of LNG from Libya. The LNG will be delivered to Texas Eastern’s peakshaving plant on Staten Island (Figure 5) which is near the eastern terminus of the company’s existing pipeline system. The plant consists of facilities and equipment originally designed to liquefy, store, and revaporize pipeline natural gas. The 600,000-barrel capacity prestressed concrete storage tank is constructed near grade with an earthen berm to provide the safety features and insulating
characteristics of other inground storage facilities. The Esso “Brega” is shown (Figure 6) unloading her cargo of 240,000 barrels of LNG from Algeria during the winter of 1970.

There is a long-term prospect for base load importation of LNG from countries with surplus natural gas production and/or reserves (Figure 7) such as Algeria, Libya, and Nigeria in Africa; Saudi Arabia and Iran in the Middle East; Brunei and Australia in Oceania; Russia; and Venezuela. The estimated natural gas reserves that could be available for such base load import projects are shown in Table 2. It is interesting to note that the proved reserves of Russia surpass those of the Middle East.

In June, the Federal Power Commission approved a plan by El Paso Natural Gas to import LNG from Algeria. It was the first approval for use of massive, long-term overseas gas supplies in the United States. El Paso will import one billion cubic feet daily under a 25-year contract valued at more than eight billion dollars. Facilities in Algeria for liquefaction and terminaling and on the East Coast for terminaling and vaporization are expected to cost nearly one and a half billion dollars more. The LNG will be sold to distribution companies for about 94 cents per thousand cubic feet.

Liquefied natural gas facilities currently in operation are shown in Table 3. About 4,300 million standard cubic feet per day (SCFD) of peakshaving vaporization capacity is available in the United States and Canada and about 570 million SCFD of base load liquefaction capacity is available in Algeria, Libya, and Alaska. By 1978, almost 3,000 million SCFD of liquefaction capacity will be added to existing Algeria and Alaska sources and added as grassroots facilities in Trinidad and Brunei.
TABLE 2 - Estimated Natural Gas Reserves
(Dec. 31, 1971)

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World Consumption

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SUBSTITUTE NATURAL GAS FROM NAPHTHA AND LIGHTER HYDROCARBONS

The production of substitute natural gas (SNG) from naphtha, propane/butane mixtures or natural gas liquids offers a solution to increasing the nation's gas supply on a short-term basis. Naphtha gasification is commercially proven, existing transportation equipment can be used, plants can be built quickly, and capital cost is low in comparison with other types of units.

The gasification of naphtha by low temperature catalytic steam reforming was developed in the 1960's by the British Gas Council, Lurgi of Germany, and the Japan Gasoline Company to make low Btu town gas or synthesis gas. The commercial plants built under license to make town gas are summarized in Table 4. The Gas Council has the largest installed capacity with over 800 million SCFD and Lurgi has in excess of 250 million SCFD for town gas production.

Examples of the European and Japanese plants built for town gas manufacture are shown in the next series of photographs. Figure 8 shows a Gas Council plant at Killingholme, East Midlands Gas Board, with a capacity of 72 million SCFD. Figure 9 shows a Lurgi-licensed town gas plant at Speyer, Germany with a capacity of 37 million SCFD. Figure 10 shows the 14 million SCFD methane-rich gas plant at Osaka Gas licensed by Japan Gasoline Company.

Town gas plants operate primarily during the winter months to accommodate peak demand as contrasted with most of the United States.
States’ facilities which will operate base load year around. The usefulness of the town gas plants in Great Britain has been dated because the country is converting many of the town gas systems to natural gas which has been found in great abundance in the North Sea.

Town gas is a 400 to 700 Btu per cubic foot gas containing methane, hydrogen, carbon monoxide, and carbon dioxide. The chemical makeup of town gas and substitute natural gas can best be illustrated (Figure 11) by the equilibrium gas compositions resulting from steam-naphtha reforming or gasification. Four chemical constituents are common to substitute natural gas, town gas, and synthesis gas but in different proportions depending on the temperature of the reforming operation. Low temperatures favor the formation of methane, whereas high temperatures favor hydrogen production. A low temperature reforming operation is required for efficient methane production and forms the basis for the process design of the proposed SNG plants.

Although town gas processes were not designed to make pure methane because England, Europe and Japan gas grids never required high Btu gas, methanation facilities and a carbon dioxide removal step are included in the process designs to raise the heating value to about 1,000 Btu per cubic foot for the United States’ requirements. The process licensors have conducted pilot plant studies of the methanation step to obtain design information. The Gas Council has installed full-scale methanation facilities at the 30-million SCFD town gas plant at Stoke-on-Trent and the 7-million SCFD town gas plant at Portsmouth.

A typical process flow scheme available for gasifying naphtha is shown in Figure 12. The naphtha feed arrives in plant storage and may be prefractionated to produce a cut for fuel requirements. The prefractionated feed is mixed with hydrogen and desulfurized by converting the organic sulfur impurities to hydrogen sulfide with a nickel-molybdenum catalyst. The hydrogen sulfide is processed in a Claus sulfur converter and tail gas cleanup. The desulfurized naphtha is mixed with
a nickel catalyst. The methanator product is scrubbed to remove unconverted carbon dioxide, dried and compressed to pipeline pressure. The SNG has a heating value of about 995 Btu per cubic foot, 98 percent methane, one percent hydrogen, one percent carbon dioxide, and specification moisture content. The substitute natural gas is fully compatible with gas from conventional sources and meets the flashback, liftoff and yellow tipping specifications.

The chemical reactions that occur in the gasifier and methanator are summarized in Figure 13. The gasification reaction which produces carbon monoxide and hydrogen, requires heat; and the hydrocracking, water gas shift and methanation reactions generate heat. These heats are balanced and the gasification reactor operates essentially adiabatically. The catalytic methanation reactor operates adiabatically and the reaction gases must be cooled and water removed. The low temperature catalytic steam reforming process has a thermal efficiency (heating value of SNG product divided by heating value of naphtha feed to the process and naphtha fuel) in excess of 90 percent.

The nickel catalyst accelerates the rates of gasification and methanation at moderate temperatures without being consumed by the reaction. The life of the catalyst is dependent upon
nickel crystallite growth and carbon buildup due to the Boudouard reaction. The state-of-the-art in gasification catalyst and process development is rapidly changing. Efforts are being made by the three licensors to improve the catalyst performance at high pressures and with higher endpoint feedstocks, reduce the cost of catalyst and steam requirements, and develop catalyst regeneration and handling techniques.

United States’ utilities have announced plans (Table 5) for about two dozen gasification plants based on purchased naphtha or lighter hydrocarbons with a total capacity in excess of three billion SCFD of SNG. If all these proposals were approved by the Federal Power Commission and other regulatory bodies, these plants would supply five percent of the nation’s gas requirements. Seven projects have progressed to the construction phase. The capacity of the plants under construction varies from 20 to 250 million SCFD. The cost of the gas produced from naphtha is due primarily to feedstock cost and is not capital sensitive.

One proposed naphtha gasification concept of a 500 million SCFD plant processing 110,000 barrels per stream day (BPSD) of naphtha is shown in Figure 14. The entire plant, including offsites, occupies 200 acres. The plant costs 140 million dollars and the naphtha receiving terminal and naphtha pipeline cost 60 million dollars. A block model of the process facilities is shown in Figure 15.

Since the availability of naphtha may limit the number of these plants, considerable interest has been shown by refiners and utilities in planning crude oil refining operations adjacent to naphtha gasification plants to prepare naphtha and low-sulfur fuel oil. The co-production of low-sulfur fuel oil may contribute substantial credits and prove attractive to combination utility companies.
Although no commercial processes are available for the direct conversion of crude oil or residual oils to SNG, it is entirely feasible to combine conventional refinery operations to produce naphtha with a low temperature catalytic steam reforming process (Figure 16). Virgin naphtha and hydrocracked naphtha from conversion of heavy gas oil and residuum cuts are fed to a catalytic steam reformer for SNG production. Low-sulfur fuel oils are produced in the hydrocracker.

Six companies have proposed crude oil refinery facilities (Table 6) with a total SNG capacity of 1,600 million SCFD and crude throughput in excess of 750 thousand BPSD. The United States Department of the Interior has recently proposed a plan designed to encourage the construction of domestic refineries for processing imported crude oil into low-sulfur residual oil or SNG or both. These energy refineries would be given governmental permission to import crude oil outside the limitations of the present quota restrictions.

Two processes for direct gasification of crude oil have been developed by the British Gas Council and could eventually find application for SNG manufacture. The Fluidized Bed Hydrogenator (FBH) is a non-catalytic process which hydrogenates the whole crude oil in a fluidized bed of coke particles to methane- and ethane-rich gas which is purified and further processed to SNG in a secondary catalytic hydrogenator. The manufacture of external hydrogen is very expensive.

The Gas Recycle Hydrogenator (GRH) is also a non-catalytic process which is claimed to hydrogenate a 650 degrees Fahrenheit distillate fraction in a stream of recirculating reacting gases and vapors. Over fifty GRH reactors have been successfully operated in Britain and Europe on lower endpoint distillates to produce 850 Btu per cubic foot gas, but the GRH has not been commercially proven with 650 degrees Fahrenheit endpoint distillates and secondary hydrogenation to make SNG.

**TABLE 6 – Proposed Crude Oil Refinery Facilities to Make Naphtha and Low Sulfur Fuel Oil**

<table>
<thead>
<tr>
<th>Service</th>
<th>Company</th>
<th>Category</th>
<th>Location</th>
<th>Source</th>
<th>Total Feed</th>
<th>Sulfur</th>
<th>Capacity</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1973</td>
<td>Howard Oil Refining</td>
<td>Philadelphia Electric</td>
<td>Philadelphia</td>
<td>Import</td>
<td>100</td>
<td>177</td>
<td>100</td>
<td>BPSD</td>
</tr>
<tr>
<td>1974</td>
<td>Crown Central Petroleum</td>
<td>Columbia Gas</td>
<td>Baltimore</td>
<td>Middle East</td>
<td>100</td>
<td>177</td>
<td>100</td>
<td>BPSD</td>
</tr>
<tr>
<td>1974</td>
<td>New England Petroleum</td>
<td>Ingersoll Rand</td>
<td>New York</td>
<td>Netherlands</td>
<td>100</td>
<td>177</td>
<td>100</td>
<td>BPSD</td>
</tr>
<tr>
<td>1974</td>
<td>North Oil</td>
<td>Phoenix Oil</td>
<td>Canada</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>1975</td>
<td>Capital/Union</td>
<td>NA</td>
<td>Louisiana</td>
<td>USA</td>
<td>500</td>
<td>100</td>
<td>500</td>
<td>BPSD</td>
</tr>
<tr>
<td>1975</td>
<td>Monarch Oil</td>
<td>United Gas</td>
<td>Pennsylvania</td>
<td>USA</td>
<td>340</td>
<td>250</td>
<td>340</td>
<td>BPSD</td>
</tr>
</tbody>
</table>

Substitute Natural Gas from Coal

The United States' domestic coal reserves are the preferred long-range source of substitute natural gas because of the large resource base, relatively

**FIGURE 16 – Crude Oil Process to Make SNG and Low Sulfur Fuel Oil**

**FIGURE 17 – Major Coal Reserves**

**AMERICAN GAS ASSOCIATION DATA**

176 POTENTIAL SITES
175 BILLION TONS OF COAL
542 TRILLION CUBIC FEET SNG
cheap cost, and national security considerations. However, environmental opposition to strip mining of coal and high capital requirements for coal gasification plants are problems that will have to be overcome before coal plays a vital role in the nation’s gas supply.

The coal fields of the United States (Figure 17) contain 1.5 trillion tons of mapped coal in relatively thick beds with overburden depth of less than 3,000 feet, enough to produce in excess of 20,000 trillion cubic feet of SNG or about 1,000 years supply of gas at 1971 consumption rates. The American Gas Association reported that it identified 176 potential sites with sufficient uncommitted coal reserves and water to supply SNG plants of 250 million SCFD capacity. These sites contain a total of 42 billion tons of recoverable coal, or enough to make 542 trillion cubic feet of SNG. About 80 percent of the sites were west of the Mississippi.

Coal gasification technology was developed in 1933 by Lurgi to make town gas from brown coal. Three years later the first pilot plant was built at Hirschfelde, Germany to produce one million SCFD of town gas from lignite. First generation plants were built in Czechoslovakia and East Germany. After 1945, the process was further developed for handling high sulfur, high ash, caking and non-caking coals, high volatile coals, coke anthracite, bituminous, lignite, and peat and was applied to a new generation of plants.

The large second generation plants employing Lurgi pressure gasification technology are shown in Table 7. The SASOL plant produces about 200 million SCFD of synthesis gas. Lurgi has built thirteen pressure gasification plants with a total of sixty-three gasifiers which produce 260 million SCFD of town gas, 220 million SCFD of synthesis gas, and 150 million SCFD of fuel gas. Recently, Lurgi has combined town gas technology with gas treatment and methanation steps to develop a substitute natural gas process. Lurgi offers the only commercially proven coal gasification process.

**TABLE 7 - Large Commercial Plants Based on Lurgi Gasification of Coal**

<table>
<thead>
<tr>
<th>Location</th>
<th>Status</th>
<th>Type Coal</th>
<th>Production FLP, MCMSS</th>
<th>Product</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sasolburg, South Africa</td>
<td>1994</td>
<td>High volatile</td>
<td>130</td>
<td>Synthesis Gas</td>
</tr>
<tr>
<td>Dennau, Germany</td>
<td>1953</td>
<td>High volatile, Coke High Ash</td>
<td>55</td>
<td>Town Gas</td>
</tr>
<tr>
<td>Monewett, Australia</td>
<td>1930</td>
<td>Lignite</td>
<td>22</td>
<td>Town Gas</td>
</tr>
<tr>
<td>Dusseldorf, Germany</td>
<td>1937</td>
<td>High volatile, Coke High Ash</td>
<td>19</td>
<td>Synthesis Gas</td>
</tr>
<tr>
<td>Westphalia, Germany</td>
<td>1960</td>
<td>Westphalia, High Volatile</td>
<td>25</td>
<td>Town Gas</td>
</tr>
<tr>
<td>Calthill, England</td>
<td>1963</td>
<td>Coke, Sub. Bituminous, Coke Anthracite</td>
<td>45</td>
<td>Town Gas</td>
</tr>
<tr>
<td>Paju, Korea</td>
<td>1962</td>
<td>Anthracite, High Ash</td>
<td>15</td>
<td>Synthesis Gas</td>
</tr>
<tr>
<td>Sasolburg, South Africa</td>
<td>1964</td>
<td>High volatile</td>
<td>40</td>
<td>Synthesis Gas</td>
</tr>
<tr>
<td>Luenen, Germany</td>
<td>1967</td>
<td>Lignite, non-caking, Low Sulfur</td>
<td>150</td>
<td>Fuel Gas</td>
</tr>
<tr>
<td>Switzerland</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**A flow scheme available for gasifying coal by the Lurgi process is shown in Figure 18.** The run-of-mine coal is crushed, conveyed, sized, and stockpiled before feeding to the gasifiers. The Lurgi reactor gasifies a fixed bed of coal with steam and oxygen to produce a crude gas at approximately 900 degrees Fahrenheit and 450 pounds per square inch pressure containing methane, hydrogen, carbon monoxide, carbon dioxide and carbonization products. The composition of the crude gas is determined by the pressure, temperature, steam/oxygen ratio, and the reactivity and volatile matter of the coal.

The crude gas is scrubbed of coal dust and tarry materials and some of the crude gas is shifted to enrich the gas in hydrogen. The cooled, shifted gas enters the acid gas removal unit which absorbs hydrogen sulfide and some carbon dioxide with cold methanol. The hydrogen sulfide is sent to a Claus sulfur converter. The treated gas is methanated over a nickel catalyst. The methanator
product is scrubbed in the second stage of the gas treater to remove carbon dioxide and water and is compressed to pipeline pressure. The SNG has a heating value of about 970 Btu per cubic foot, 97 percent methane, one percent hydrogen, one percent carbon dioxide, and one percent nitrogen and is fully compatible with natural gas. The tars and tar oils made in the process are recovered and can be used as fuel. The phenols can be recovered for sale.

The chemical reactions that occur in the Lurgi gasifier, shift convertor, and methanator are summarized in Figure 19. Part of the coal is combusted with oxygen to provide the heat requirements for the steam gasification reaction. The devolatilization and hydrogasification reactions produce methane directly. The water gas shift is needed to provide the proper hydrogen content to react with the carbon monoxide in the methanator. The Lurgi process has a thermal efficiency (heating value of SNG product divided by heating value of coal feed) of approximately 70 percent.

A detailed view of the Lurgi gasifier (Figure 20) shows the coal lock chamber, coal distributor, water jacketed producer chamber, ash grate, and ash lock chamber. Crude gas is removed near the top and sent to the scrubber. The interior of the Lurgi gasifier house at the Westfield Gas Works of the Scottish Gas Board is shown in Figure 21.
Some pilot plant programs are demonstrating the methanation of high concentrations of carbon monoxide produced in the Lurgi process. Staging of the fresh feed gas to dilute the carbon monoxide and interstage cooling to remove the reaction heat, will allow better control and limit temperature rises to permit reasonable catalyst lives. One United States petroleum company with coal interests is directing a program to demonstrate on a commercial basis the Lurgi coal-to-SNG process at the Westfield Works. Acid gas treating facilities and methanators will be installed and design data should be available by mid 1974.

Three gas transmission companies have announced plans (Table 8) to construct coal gasification plants with a total capacity of 750 million SCFD of SNG based on Lurgi technology. Two of the proposed sites are located in Northwest New Mexico and a third site in Illinois. The cost of the gas produced from coal is due primarily to capital charges and is not extremely sensitive to the price of coal.

One proposed 250 million SCFD coal gasification plant is shown as a block model in the next series of photographs. The overall plot plan (Figure 22) occupies a space one mile long and one-third mile wide not including the coal preparation facilities. The plant is located near a gas transmission line from West Texas to the California border. The process plant and offsites, not including coal preparation facilities, could cost at least 300 million dollars. About 700 people will be employed by the facility during normal operation. Figure 23 shows the thirty Lurgi gasifiers which are fed about 22,000 tons of coal per day derived from local strip mining operations. Figure 24 shows the Rectisol acid gas treating facilities and Figure 25 shows the Phenolsvolan facilities to recover phenols.

Although Lurgi has the only available commercially proven coal

**TABLE 8 — Proposed Commercial Coal Gasification Plants**

<table>
<thead>
<tr>
<th>Service Year</th>
<th>Company</th>
<th>Location</th>
<th>Coal Rate TPD</th>
<th>NG Production MMSCFD</th>
<th>Cost $ MM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1976</td>
<td>Pacific Lighting/</td>
<td>NM, New</td>
<td>22,000</td>
<td>250</td>
<td>350</td>
</tr>
<tr>
<td></td>
<td>Texas Eastern</td>
<td>Mexico</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1976</td>
<td>El Paso</td>
<td>NM, New</td>
<td>21,000</td>
<td>250</td>
<td>350</td>
</tr>
<tr>
<td></td>
<td>Mexico</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Before 1980</td>
<td>Panhandle Eastern</td>
<td>Illinois</td>
<td>--</td>
<td>250</td>
<td>--</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

References 10, 12

**FIGURE 22 — Lurgi Coal Gasification Plant Proposed for Northwest New Mexico**

![Diagram of Lurgi Coal Gasification Plant]

**FIGURE 23 — Block Model of Gasification Facilities**

![Block Model of Gasification Facilities]
differ from the Lurgi process primarily in: (1) method of supplying heat for char gasification to make hydrogen-rich gas, (2) methods of pretreating, feeding, and contacting coal with reactive gases, and (3) operating pressure level in the gasifier.

The three general processes\textsuperscript{13} for converting coal to SNG are summarized in Figure 26. The direct process at high temperature and pressure by hydrogasification requires expensive external hydrogen. The Lurgi process is an indirect process in which carbon monoxide generated by steam gasification and hydrogen produced by water gas shift are catalytically reacted in the methanator to synthesize SNG. Some methane is formed directly in the gasifier by devolatilization and hydrogasification of the coal. The indirect process has a low thermal efficiency. The combination method emphasizes hydrogasification of the coal to convert its reactive portion to methane and steam gasification of the residual char to produce the hydrogen required for hydrogasification. The remaining carbon monoxide is catalytically methanated. The heat required for gasification can be provided by partial combustion of some of the carbon.
ENVIRONMENTAL CONSIDERATIONS

Consumers, investors, and the government not only share a common interest in abundant, assured, and attractively priced supplies of energy for continued economic progress but they also share concerns about the quality of the environment.

The environmental considerations involved in any proposed naphtha or coal gasification plant are quite extensive and complex. The environmental design is dependent upon the process design of environmental standards (Table 10) regarding atmospheric emissions and wastewater quality. The government agencies require adequate design to meet sulfur, nitrogen oxide, and particulate emissions along with water quality standards and noise levels. Existing environmental and economic features (Table 11) that must be considered are the natural environment and human environment.

The Federal and State environmental regulatory authorities require the owner of the proposed facility to develop the above information into a

**TABLE 10 — Federal and State Regulations**

<table>
<thead>
<tr>
<th>Atmospheric Emissions and Wastewater Quality</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SULFUR</strong></td>
</tr>
<tr>
<td><strong>NITROGEN OXIDE</strong></td>
</tr>
<tr>
<td><strong>PARTICULATE MATTER</strong></td>
</tr>
<tr>
<td><strong>SPECIFIC FOR COAL GASIFICATION PLANTS (STATE)</strong></td>
</tr>
<tr>
<td><strong>MAXIMUM SULFUR AND PARTICULATES</strong></td>
</tr>
<tr>
<td><strong>WASTEWATER DISCHARGE QUALITY (STATE)</strong></td>
</tr>
<tr>
<td><strong>BIOLOGICAL OXYGEN DEMAND</strong></td>
</tr>
<tr>
<td><strong>CHEMICAL OXYGEN DEMAND</strong></td>
</tr>
<tr>
<td><strong>SOLIDS</strong></td>
</tr>
<tr>
<td><strong>pH</strong></td>
</tr>
<tr>
<td><strong>COLIFORMS</strong></td>
</tr>
<tr>
<td><strong>TRACE METALS</strong></td>
</tr>
<tr>
<td><strong>SOLID WASTE DISPOSAL</strong></td>
</tr>
<tr>
<td><strong>NOISE</strong></td>
</tr>
</tbody>
</table>

**TABLE 11 — Existing Environmental and Economic Features**

| **NATURAL ENVIRONMENT**                      |
| **PHYSICAL AND CHEMICAL**                    |
| **LAND**                                     |
| **AIR**                                      |
| **WATER**                                    |
| **BIOLOGICAL**                               |
| **TERRESTRIAL**                              |
| ** ATMOSPHERIC**                             |
| **AQUATIC**                                  |
| **RESOURCE UTILIZATION**                    |
| **LAND**                                     |
| **AIR**                                      |
| **WATER**                                    |
| **HUMAN ENVIRONMENT**                       |
| **ECONOMIC**                                 |
| **INDIVIDUALS**                              |
| **REGIONAL**                                 |
| **SOCIAL**                                   |
| **COMMUNITY STRUCTURE**                     |
| **INDIVIDUAL BEHAVIOR**                     |
| **HUMAN INTEREST**                           |
| **AESTHETICS**                               |

**TABLE 12 — Environmental Impact Statement Contents**

<table>
<thead>
<tr>
<th>DESCRIPTION OF THE PROPOSED ACTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>ENVIRONMENTAL IMPACT OF THE PROPOSED ACTION</td>
</tr>
<tr>
<td>ADVERSE IMPACTS WHICH CANNOT BE AVOIDED SHOULD THE PROPOSAL BE IMPLEMENTED</td>
</tr>
<tr>
<td>ALTERNATIVES TO THE PROPOSED ACTION</td>
</tr>
<tr>
<td>RELATIONSHIP BETWEEN LOCAL SHORT TERM USES OF MAN'S ENVIRONMENT AND THE MAINTENANCE AND ENHANCEMENT OF LONG TERM PRODUCTIVITY</td>
</tr>
<tr>
<td>IRREVERSIBLE AND IrRETRIEVABLE COMMITMENTS OF RESOURCES WHICH WOULD BE INVOLVED IN THE PROPOSED ACTION SHOULD IT BE IMPLEMENTED</td>
</tr>
<tr>
<td>DISCUSSION OF PROBLEMS AND OBJECTIVES RAISED BY OTHER FEDERAL, STATE AND LOCAL AGENCIES AND BY PRIVATE ORGANIZATIONS AND INDIVIDUALS IN THE REVIEW PROCESS</td>
</tr>
</tbody>
</table>

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comprehensive "Environmental Impact Statement" filed with the Federal Power Commission as the "lead" agency. The Environmental Impact Statement (Table 12) must consider seven points in response to the requirements of the National Environmental Protection Act of 1969.

CONCLUSIONS

In conclusion, the big energy supply job cannot be done by development of nuclear energy sources alone but will have to be done by oil and natural gas and gas from coal for a long time to come. This fact means conventional domestic exploration and drilling must be accelerated, and new technologies for discovering and recovering oil and natural gas must be developed. Simultaneously, commercially feasible, large-scale supplemental gas supply projects—such as gasification of naphtha, crude oil, and coal and imported liquefied natural gas—will be needed to augment conventional supply. While the investments in time, effort, and capital to accomplish this will be high and will result in higher prices for gas and other energy sources, the alternative of less available energy will be much less appealing and inconsistent with sound national goals.
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PRACTICAL EVALUATION GAMESMANSHIP
By Dr. John M. Campbell, John M. Campbell and Company
Norman, Oklahoma
Presented at the Eleventh Annual Meeting of
The Society of Petroleum Evaluation Engineers
Mexico City, November, 1973

Evaluation is the determination of value for a given equity within a value system, not merely the name of a calculation procedure. This means that anything affecting value must be a part of the evaluation, even if it cannot be incorporated formally into an equation. Value will be fixed, therefore, by the reservoir characteristics, production practices and a whole bunch of things like political, ecological, cultural, marketing and international monetary considerations. Only the first two of these may be described reasonably with explicit type equations that are typical of reservoir engineering.

To a large extent, evaluation is an exercise in uncertainty because one is always using a series of inexact numbers and numbers which depend to a large extent on the future uncertainty of events yet to occur. One is faced with the alternative of trying to play "God" or to face up to this uncertainty in a reasonable manner in order to arrive at answers which are both reasonable and useful for decision purposes.

There are several basic forms of uncertainty which exist in an evaluation.

1. The amount and quality of raw data
2. The ability of mathematics to characterize the reservoir system under study
3. Lack of control of future events

A certain amount of this uncertainty can be taken care of in a formal manner by the application of statistics and probability. One can analyze the data available, using reservoir principles which we understand, and arrive at a likely distribution of answers useful for decision purposes.

Gamesmanship

Practical gamesmanship is the ingredient in an evaluation which transforms the usual routine reservoir type of calculation into a meaningful evaluation. Yet, technically trained people tend to reject gamesmanship as part of their skills portfolio; they prefer to "hide behind" their numbers and the "black magic" associated with said numbers. This is understandable by virtue of the fact that technically trained people are number-oriented. Such numbers are somewhat comfortable and appear to have a positive meaning.

Gamesmanship really is the thing you add to any technical effort. It involves the mind in its creative and logic applications. This is particularly important because an evaluation is just not a simple reservoir engineering calculation with some economic number tacked on the end to translate reserves and production rates into money. It involves some basic understanding of the economic system within which the evaluation falls and the likely effect of future events on the value which is now being ascertained.

In many cases the person making the evaluation is not a participant in the final decision process. His problem is to include in the evaluation report those factors necessary to reach a proper decision without infringing on, or controlling, the decision process which is the responsibility of others. Too often then, the evaluation process evolves down to nothing more than running out a set of numbers in the routine manner prescribed by the company or the client with little else transmitted to guide the final decision process. The thing that is lacking is what I am calling gamesmanship.

There are many similarities between games like basketball and football and the affairs

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of men in the business world. It is probably one of the reasons why such games attractive to the people in general because it enables them to participate in a game during their leisure hours in which they are not directly involved.

Any game operates within a set of rules. In the evaluation game our rules are those physical laws governing the behavior of the reservoir systems and the economic rules which establish the value of goods stored in the "reservoir warehouse." It is obvious that understanding of the rules is a necessary part of playing a winning game. One cannot play well without understanding rules. But, this is not enough. In order to win one must have well qualified personnel and a "game plan."

A game plan is nothing more than a plan of action which is designed to provide a positive result in a given circumstance. In football, a coach develops a game plan (within the rules) which is based on the assessment of his team's strengths and weaknesses and those of their opponent. It is hopefully a realistic assessment of the situation as it really is. Whether he wins or not depends on how realistic the plan is.

This is the situation in evaluation. Factors affecting value are not the same for each company at a given time in different locations. Evaluation of a small lease in Oklahoma or Texas is infinitely different than the evaluation of a lease in deep water in the North Sea. In fact, the calculations might be a great deal different in the two locations and not look at all alike, at least superficially. What I am saying is that true evaluation can never be simplified to filling out a form or running a routine calculation. Some element of personal judgment and experience must always be added.

One may be limited to merely filling out the blanks on a form for computer input, fixed by a simple given equation, or so bound in any way that this becomes a routine number plugging operation. This is equivalent to handing a football rule book to a pigeon-toed, knock-kneed, clumsy boy in the hope of converting him into a halfback. We readily recognize that this would be rather ridiculous in coaching football. Yet, we tend to do the same thing to our young engineers when trying to teach them evaluation procedures.

Almost all athletes who excel add some personal dimension of their own to the rules and game plan with which they have been provided. They add imagination and skill. I believe that the same thing applies to the evaluation procedure. It is very important that evaluations be consistent so they can be handled routinely and provide easy communication within an organization. The content of these evaluation reports must follow within a certain format. They must contain "yardsticks" which are commonly used in the company's decision process and are supposedly understood by the people using them. At least these common yardsticks have been used in past decisions and there is some measure of feedback on the result of those decisions.

It is proper to require these things but not at the expense of preventing an individual person from "free lancing" a bit to inject thoughts and philosophy which might serve as a guide to those at the decision level. A good coach is going to insist that his players stick to the basic game plan, but he will also be wise enough to know that how the players utilize their talents within that plan will vary somewhat with the individual.

Gamesmanship contains two ingredients. The first is the development of a flexible game plan that is adaptable to the individual circumstances that exist. The second aspect is giving the individuals operating the game plan enough leeway so that they can inject a measure of their own talents. It is not necessary to abandon or even change that which has worked for the organization. This is merely the base for the addition of individual talent rather than a boundary which limits the talents of the evaluation itself.

Basic Rules

Unfortunately the basic rules of the game keep changing as circumstances around the world keep changing. The basic rules of reservoir engineering have not changed very much in the last twenty years
although we are now able to apply these rules somewhat more effectively by the use of machine computation. Computers not only save time but they enable us to handle more numbers and handle the reservoir in a bit more detail. Techniques involved here are very familiar. This is one part of our rules that is relatively well understood.

The second part of our rules involves economics. This is the part that the engineer and geologist oftentimes understands the least. Unfortunately, once one develops even a modest understanding of these rules they have a way of changing.

Prior to about the middle 1950's the economic factors were a very small part of our rules system. The demand for oil kept pace or even exceeded the supply. This means that if a person could find oil he could be assured of a relatively short pay-out. His only problem, therefore, was finding enough oil to recover his costs with a reasonable profit. Economic factors like payout, value of a daily barrel and leverage were the primary factors which concerned the person making the decision on the value of a petroleum reservoir.

Leverage took several forms but usually involved simply calculating the ratio of undiscounted future revenue divided by the investment cost. So long as this leverage was 2 to 1 or above, many people would consider the investment to be a good one economically. Time value of money was an insignificant factor because of short pay-outs normally involved. Formal evaluation of risk was not of significant concern because a large number of wells were drilled and the cost of any single well did not involve a substantial part of the equity available to a major company. With short payouts and efficient internal generation of capital for exploration and exploitation, economic rules were understandably very simple.

In the middle 1950's there was a substantial change in the economic rules. Supply pretty well caught up with demand. At this point many of the obvious, shallow, cheap reservoirs had been discovered and the cost of exploration started rising dramatically. Payout times became much longer and it was not at all uncommon to look at payouts of four years and beyond. This meant that companies were tying up their available capital for longer periods of time. In addition they were drilling deeper reservoirs and going to the off-shore provinces where the "front end load" was becoming somewhat burdensome in terms of the availability of internally generated capital. It was at this point that the companies began using ever increasing amounts of borrowed capital for the development of reserves.

Because of these considerations the oil industry became acutely aware of the time value of money. Although these were new to this industry they had been used historically in other industries for some time. All of these equations were some algebraic adaptation of some common compound interest equations which reflect the cost of "renting" money.

It was realistic to charge oneself rent for capital tied up from the company treasury since this money could be invested in other places in addition to the project being evaluated.

You are all familiar with the various forms of these equations. Although the principle of these is very simple, the rules that have been developed for their use are far from uniform. Almost an infinite number of algebraic forms can be developed although five or six forms have been used most commonly in history. Because of the large number of potential forms available the rules are not uniform throughout the industry. It is common for each company to have one or more forms which become more or less official and which people are taught to use somewhat routinely. There is really nothing wrong with this except that the use becomes so routine that people simply react to the results of a calculation and never really think about what it means in terms of the specific situation in which the equation is being applied. What I am saying is that the fault lies not so much with the equations being used as the way in which people use them.

Regardless of what equation people use, or how they use it, the calculation usually either boils down to calculation of a rate of return, the present value profit, a net
present value or some type of net present value or profit ratio with the denominator being the investment cost of the project. I believe it is fair to say that because of the problems with rates of return the bulk of the industry is using some method of discounting future revenue or appreciating present revenue to the end of the basic means of establishing value. However you do this is not particularly critical as long as you recognize that all you can end up with is a yardstick of value which is merely one input into the evaluation and not an evaluation itself.

This technique is fairly realistic provided one has a reservoir with a reasonable like and not too much time delay between the initiation of development and the flowback of some revenue from the result of the development. But on large reservoirs involving high investment costs and very long lives, the use of some form of discounting in itself does not turn out to be a realistic method of establishing value. Using common discount rates, a unit of money received 20 years hence has very little value when discounted back to the present. The net result of this is that long-lived reservoirs tend to have a fairly low rate of return or a very low discounted value which tends to make the higher productivity reservoirs appear more attractive. In this circumstance I do not believe that routine use of discounting is a realistic yardstick for evaluation. On the assumption that the organization is going to be infinite in life, what one is really concerned about is what is the real value of a barrel of oil to the company produced 20 years hence. That value is going to be fixed by what it costs to obtain that future unit of money and the purchasing power of that money in year 20.

What does it cost to obtain that barrel of oil in year 20? In the first place one has to rent money either from himself or from others to develop the reservoir which will be capable of producing that barrel of oil in year 20. This rent, however, only applies until one reaches what I call "discounting payout time." One is going to pay rent on money in the given reservoir project until the revenue of the project equals the initial capital cost plus the dept service on that particular cost. Beyond discounted payout there is no borrowed money, from any source, involved. All money coming from this particular project is new money unencumbered by any debt charges whatsoever. Is it realistic to discount money received beyond discount payout time at the same rate as one did before?

This does not mean that there is no discounting whatsoever. But you must recognize that money is not wealth per se; it is merely a means of exchanging wealth. So, money received in year 20 will have a lesser purchasing power than it does at the present because of the inevitable inflationary aspects which seem to be an integral part of our economics. It is reasonable, therefore, to discount revenue beyond discounted payout time to reflect the lesser purchasing power of money with time.

Of course, one might choose not to do this if he is willing to make the assumption that the selling price of the reserves produced will more or less keep pace with inflation and therefore the selling price is varied in the calculation to automatically take care of this. This has not been true historically and therefore people tend to be reluctant to use this assumption.

I believe that the future price of oil will not only keep pace with inflation but will actually outstrip it because of supply/demand considerations. I therefore recommend that no discounting whatsoever be used beyond discounted payout. Whether you do this or not will depend upon the "game plan" that a given organization develops.

There is one other aspect of discounted payout which I think is most important. That stems from the fact that a large portion of the world's reserves have been developed in areas for which the consuming countries have little or no control. Many of these are developing countries with inherent political instability. In turn, contracts really mean very little since these are changed at the discretion of the producers. This introduces a risk that cannot be handled formally in any type of equation. It simply means that the quicker one can get his risk capital back the less inherent risk that is involved. Discounted payout time is therefore very important because this represents the time at which there is no longer any risk capital
involved in the project. The shorter this time, the less the inherent future polici-
cal risk. For both of these reasons I strongly recommend the use of discounted 
payout time as one of the yardsticks in the evaluation of a long-lived property in order to get a measure of the time risk of the capital being put into the project. I also recommend that discounting future revenues be discontinued beyond the dis-
counted payout time period.

This is only one example of the use of the traditional time value of money equa-
tions. One can cite innumerable modifica-
tions of these equations to be realistic in a given evaluation situation. I recog-
nize that continued modification of these techniques introduces certain communica-
tion problems and makes them less than rou-
tine. However, I would advance the thought that making these less routine would en-
hance the ultimate worth of the evaluation. As we have less, more critical,pro-
spects to evaluate, it is important that these be more than a routine "meat grinder" type operation.

Forecasting

There is one final element in the pro-
per gamesmanship that we are discussing. This is the forecasting of product prices and future elements which will affect the establishment of value. This is intangi-
ble in the sense that it cannot be put in-
to equation form and has built within it many of the biases, wishes, and guesses 
that represent a high degree of human judg-
ment. If we relate this to a sport type of 
game, we are talking about what is equi-
valent to the things like spirit, home 
field advantage and other such things which always affect the outcome of a sport-
like game in some intangible way.

I raise this issue because the oil busi-
ness has not done a very good job of the forecasting of future events, as a general rule. Most forecasting has simply been a 
routine extrapolation of trend lines with-
out much regard for the factors that went into those particular lines. One can nev-
er forecast exactly, but one can analyze the factors which went into a given con-
sumption number or a price number to as-
certain in some way the role that each of these factors might have played in causing
the situation to date. I believe this is very important because the petroleum in-
dustry is entering an era where much of our historical information is probably in-
valid. Some will disagree with this state-
ment, so I think it is necessary to docu-
ment at least briefly my reasons for saying this.

Historically, the price of crude oil and 
natural gas has been a fairly inflexible 
system from the economic's viewpoint. Un-
til recent years the price charged for 
these products, at least in the crude stage has been largely independent of demand. In 
fact, as one looks at the history of pricing, it is apparent that there were many 
periods of time where the price of these products varied very little even though 
there was a large degree of inflation and a large increase in demand. Only in re-
cent years have U.S. prices been influ-
enced by supply and demand considerations.

The bulk of the available oil reserves 
today are controlled by a cartel of Middle 
East nations. As long as this cartel(called 
OPEC) is effective they can fix the price with no concern as to the effect on the 
market. This cartel can operate so long 
as each of the member nations does not suf-
er unduly by the curtailing of production and the artificial fixing of prices. This 
makes it very difficult, if not impossible, 
to make a logical extrapolation of the 
price structure at this time.

It is difficult to extrapolate histori-
ical price and demand trends for another 
reason. As the price of crude oil and 
natural gas increases many of the tradi-
tional markets for these materials is go-
ing to change drastically. At some point, for example, I believe we are reaching a 
point where the bulk of the available natu-
ral gas will go into petrochemical manu-
facture rather than used as boiler fuel. 
It is certainly going to be curtailed for 
boiler fuel and power generation, and other 
commercial uses, where convenience is not 
as important as service to individual homes.

Large individual consumers of energy 
find it reasonable to use alternative sour-
ces of supply much more conveniently than 
can the individual homeowner from purely 
a logistics point of view. This type of
move is also politically feasible. A natu-
real part of these price increase, whatever
they might be, will also trigger develop-
ment of alternative sources of energy for
consumption by the public, such as nuclear
power, solar energy, the wind, etc., etc.

Still another factor is the fact that
the general public has been wasteful of
energy simply because it was so cheap and
represented a very small portion of the
individual budget. I think it is inevi-
table, for example, that people will be
purchasing smaller cars, which is going
to cut the fuel consumption to a much lower
figure. There will be changes in con-
sumption patterns industrially and in the
large stores and shopping centers when
the cost of energy to heat or cool the
area becomes a critical factor or the en-
ergy is simply not available at any price.
What I am saying in effect is that there
is going to be a basic change which is
going to affect the energy consumption
per capita.

There is also the effect of birth con-
trol methods and their effect on the con-
sumption of energy. Historically, I have
found it rather feasible to extrapolate
energy consumption by looking at birth
rate patterns. As a general rule you will
find that there is a time delay of about
sixteen years between the birth of a per-
son and his extra consumption of energy.
This is the age at which most young peo-
ples begin to drive and utilize more au-
tomobile fuel. About twenty years after his
birth the person starts becoming an extra
consumer of energy because this represents
the age of marriage and the establishment
of a household, which adds even further to
the total energy consumption. If one fol-
low this general pattern you achieve a
rather good correlation in terms of in-
dividual consumption. The correlation is
certainly as good as most engineering
correlations that we employ.

I raise this point because the bulk
of the developed world is approaching a
zero population growth. This means that
if per capita consumption were to hold
constant at the present rate, there would
be a leveling off in the demand for en-
ergy based, if nothing else, on the lower
population growth rate involved. Since I
believe the ultimate result will be for
the consumption of developed countries to
decline per capita this would have even
more of a leveling influence at least in
the near future. Of course, as more of the
countries in the world develop and require
greater amounts of power this will be null-
ified to some degree, but one can fore-
cast this far enough into the future so
that it has very little effect on the cur-
rent value of an existing petroleum reser-
voir property. What I think we will see in
consumption is a leveling off of the cur-
rent curves followed of course by a grad-
ual rise to a new peak. I think we should
recognize though that by the time we get
into the year 2000 and reaching toward a
second peak, the bulk of the energy con-
sumed for heat and cooling probably will
be furnished from non-fossil fuel sources.

One could outline a number of factors
like this which enter into the forecast-
ing of energy demand and therefore the ul-
timate value of fossil fuels. The major
point that I want to make at this time is
simply that one cannot simply extrapolate
lines as is usually done in most of the
graphs that one sees in the literature.

After making these comments I cannot
resist the temptation to make some more
exact predictions as to what is likely to
happen pricewise in the next 10 or 15 years
as they affect oil and gas. In doing this
I am using substantially the same techni-
ques that I used back in 1958 to predict
the current oil crisis now hitting the
United States. There are really five dif-
ferent comments that I want to make. I'm
afraid that I cannot document these in de-
tail at this time since time does not per-
mit. I will simply make the comments,
give a brief documentation, and then let
you decide if they are reasonable or not.

1. Gas Price and Demand
First of all, we have to face up to the
fact that demand for gas has been due to
the fact that it has been essentially
under-priced in the market ever since
the beginning of substantial gas pro-
duction. Its rapid growth was somewhat
abnormal for this reason although its
mere convenience has been a major fac-
tor. The price of natural gas at the
wellhead, where it can be transported
to the market via pipeline in the gas-
eous state, must ultimately rise to a value of around a dollar per thousand standard cubic feet in order to insure a sufficient supply for the immediate future. I believe, as do many others, a price of around $1 per thousand standard cubic feet in the U.S. would spur gas supply sufficiently to get us over the short range five year hurdle that we now face. The price will depend on course on the transportation cost and other factors like this, but there is no way that alternative sources of gas can be supplied for much less than $1.50 per thousand cubic feet from conversion of coal, naphtha and other possible sources of gasification processes. For these reasons I think it is feasible to look at a price of natural gas in the U.S. at around $1 per thousand standard cubic feet in the planning of exploration efforts in the relatively near future. At some point in time, of course, these prices will go well above this. But, in terms of the way most of these leases are evaluated the first five or six years represent the bulk of the value in determining whether or not a given project is worthwhile.

2. Oil Prices and Demand

This is a much more difficult thing to predict because of the cartel factors which I mentioned previously. So long as the consuming countries have no alternative sources of supply, the Middle East cartel is going to be able to get almost any price for crude oil that they demand. It is very easy to foresee prices of $8-10 per API barrel in the short term simply because these kind of prices can be paid for crude oil without a major upset in a developed nation's economy. This makes the price at the wellhead to be about $0.25 a gallon assuming that all the crude oil were converted to gasoline. With people going to smaller cars the price of gasoline in the U.S. at the pump might conceivably go to $0.60 to $0.70 a gallon under this circumstance. With smaller cars and other patterns this should not represent a major financial problem to the average consumer since gasoline represents a small part of his budget anyway.

Ultimately, however, the alternative sources of supply for crude oil are going to enter the picture and have a distinct effect on the ability of the cartel to fix prices, if indeed the cartel can hold together for that length of time. It is probably reasonable to assume that it would take five years minimum in this country to utilize our coal and oil shale supplies for the production of motor fuel and other general fuels used in the economy. I think it is also reasonable to assume that during this period commercial power generation and other things would be put into other fuel sources such as direct firing of coal, nuclear and the like. Based on current reasonable estimates we can manufacture oil from oil shale and coal at a price somewhere around $5 per API barrel.

The technology is relatively crude to what it could be, but we still have commercial technology for doing that at the present time. I think it is also reasonable to assume that in the five year period there will be sufficient inflation so that the cost of this might easily rise to as much as $7.00 per API barrel. It is usually true that as one develops a pilot technology to a full scale technology the cost of doing the function involved actually decreases with time since the technology increases more than compensates for inflation. However, a demand for plants that stretches our manufacturing capability, plus inflation, might well prevent this. I believe that the U.S. will go to these sources since they are controllable. I further believe that as these sources start coming into the market it will put very severe pressure on the OPEC cartel to modify prices and very likely make that cartel ineffective. This is merely a guess, but it's a very reasonable one based on the past affairs of men.

This means, in effect, that we are going to see the price of oil rise to a high and then fall back as alternative
sources of supply come into the competitive market. In planning current oil exploration efforts I believe this is the most logical type of variable oil price to put into the picture. As a further guess, $8.00 per barrel seems logical in the near future.

3. Change in Marketing Patterns
   I have touched on this previously. Let me simply reiterate that the traditional marketing patterns that we have had in the world for petroleum products has to change. Supply is going to diminish in the long run and is going to be used primarily for the high yield type raw material source. Use of these materials simply as boiler fuel will ultimately disappear. The current situation I think will simply accelerate what would have been a natural evolution.

4. Joint Venture Arrangements
   The traditional financing of oil ventures in countries outside the U.S. has already changed substantially. The cold hard facts of the matter are that the majority of the Continental Shelves, which hold potentially up to 80% of the future petroleum reserves of the world, are controlled by governments. For a lot of considerations, primarily political, it is difficult for governments to give these lease arrangements to private industry. I believe that there will be more joint venture arrangements in the ownership of such government leases between private companies and governments including the U.S. I see more direct financing of the development of oil resources by the owning countries, including the developing countries which build up greater cash reserves through the increased price of crude oil. In the final analysis I think that many of the major petroleum companies are going to be essentially purchasing companies who supply operating expertise, and other expertise, in exchange for the right to buy somebody else's oil on a long term arrangement. In fact, I foresee the day when most of the oil purchased between international countries will be covered under country treaties rather than by simple arrangements between a country and a private corporation. Many of my oil friends do not like the thought of such arrangements, and I must confess that I am not too crazy about them either, but in the long run they might be a better alternative than the current one wherein the private company is caught between the politics of consuming and producing governments.

5. Ultimate Value of Raw Reservoir Products
   As you all know, it has been customary for us to simply establish the value of a reservoir by multiplying the production times the wellhead price of oil and natural gas. This is a traditional approach which does not reflect properly the value of that reservoir in the total company economic structure today. If we are not there already, we are almost to the point that evaluation of a reservoir is going to be made in terms of the total value of this raw source in terms of the ultimate value of the products produced from that raw source. In the case of natural gas, the value of this gas is going to be fixed more and more by its value as a petrochemical feedstock and not by its mere value as boiler fuel.

   This is going to complicate the traditional evaluation process but is going to be necessary in order to put the value of these reservoirs in their proper perspective. It means, if you please, that the evaluation of a reservoir will not be a mere extension of the reservoir engineering function but will involve input from processing, pipeline, petrochemicals and the like. It is in fact going to change the entire pricing structure of crude oil and natural gas in addition to the factors I have mentioned previously. API gravity, for example, does not mean too much when you are talking about a feedstock for some purpose other than refining into the usual products. When you refine for other purposes you are concerned about the constituents and not merely the overall density or specific gravity of the fluid, although specific gravity might be an indirect measure of these components.
Summary

I have raised a number of thoughts, some of which are controversial. I fully realize that not all of the ideas I have expressed will turn out to be correct in the final analysis, but I do believe they will be closer to being correct than the mere extrapolation of current practices and thoughts with regard to the value of reservoir properties. We have tended to undervalue these properties historically. With the current furor over the energy crisis there are signs that we are beginning to overvalue them.

I raised the question of gamesmanship because I believe this has to be the final answer to the dilemma that the evaluation man faces today when everything is extremely uncertain. In addition to all of our other problems, we are involved with an essentially non-existent international monetary system which varies from day to day. I believe that the reasonable answer is not to panic or be reduced to a slight case of paranoia about the total situation. Rather I think gamesmanship, as I define it, offers a reasonable answer when it is combined with the same kind of sound, engineering practice that usually has been characteristic of the membership of the Society of Petroleum Evaluation Engineers. I cannot force you to agree with me on all of the subjects that I have mentioned, but I do ask you not to disregard them without giving them at least some careful thought.
BUYING OIL AND GAS PRODUCTION - TECHNICAL AND PSYCHOLOGICAL
(THE "BUYING MOOD")

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We are in an extremely fascinating industry - not only considering the oil industry as such but considering the phases of it that we as members of the Society of Petroleum Evaluation Engineers are engaged in. That is, the buying of producing oil and gas properties. The buying of producing oil and gas properties is a natural adjunct of the oil industry which is essentially a trade industry. Once the liquid of gaseous product is located and is bought into production it assumes a value. We as engineers and geologists have or should have the technical ability to properly estimate how much of this product is located in a particular reservoir. Then by utilizing this estimated amount and applying the proper economic factors to it we can properly determine a value for a particular oil and/or gas field or groups of fields. There is quite a temptation for an engineer or geologist when evaluating a prospective purchase to take the attitude that since "I am technically qualified" it is my function to look at the safety factors involved in the estimate or, as I maintain, take the negative approach, and look for reasons why the purchase should not be consummated. The purpose of this paper is to emphasize the point that in order to buy production we have to be in the "buying mood". If we have a purpose and reason together with the wherewithal to buy, then in order to do so we have to think positively and look at the "plus" factors involved and weigh them in their proper perspective to the so-called negative factors. Of course, if at the outset we see too many negative factors involved in the purchase then we should not pursue it. However, if the proper plus factors are present and there is a probability of a trade, our main function should be to try to make the trade on the best economical basis possible. Obviously, in order to do so we have to explore, positively, the reasons to make the trade.

What does a purchaser pay for production? All of us have heard the overused statement that the purchase price for a property is its "fair market value". As we know, this statement has many definitions. The most commonly used definition is that the "fair market value" is the price that a willing buyer will pay a willing seller at the market place. This in itself implies a trade type of psychology. Those of us who have purchased production within the past 18 months know only too well that we have been in a "seller's" market rather than a "buyer's" market. I can assure you that the knowledgeable seller has a good idea what his property is worth. It is our responsibility as buyers or representatives of buyers to either technically justify this value - or - not buy. If in today's market the buyer or his representative is not willing to consider product price increases as well as "plus" factors concerned with behind-pipe reservoirs, undeveloped-proven reserves, and in some instances possible exploratory reserves attributable to undrilled acreage included in the trade, he is not going to buy production. I cannot overemphasize this point!

During the past two years the main purchasers of producing oil and gas properties have probably been from the following categories of companies:

1) Fully integrated major or large independent oil and gas companies.
2) Large producing independent oil companies.
3) Various trusts, estates and/or similar institutions.
4) Independent oil companies formed for the precise purpose of buying production, with either foreign or domestic corporate capitalization.

5) Limited Partnership "Income Funds" either within established companies or newly formed companies.

All of you are familiar with the first three categories and their reasons for buying producing oil and gas properties. Basically, for the first two categories it is mainly a means of increasing the company's producing reserves basis for whatever the individual company or corporate reasons may be. As for the trusts, estates or other similar institutions, it represents a means for investing dollars in order to secure a sound future return on investment. The fourth category is not new and unique. During the mid-to-late 1950's several companies were formed and capitalized for the precise purpose of buying production. Capitalization was usually through a "group" of individuals or companies. Historically, few of these original companies survived. Most have since "sold out" to the first two categories. Recently, however, there has been a revival of this type of company mainly through foreign investors. One company in particular, of this category, has been extremely successful in buying production during recent months.

The fifth category of companies, the Limited Partnership Income Fund approach is probably the least familiar to most of us. Basically, the Limited Partnership Income Fund approach is similar to that of a trust or estate. That is, both categories are attempting to provide future income and return on investment. The main difference is that the income fund obtains its equity investment dollars by means of a SEC registered public offering and can purchase all types of producing interests whereas trusts are limited, for tax reasons, as to what type of interests they may purchase. These income fund equity dollars can then be combined with financed or "leveraged" dollars to purchase producing oil and gas interests and return yearly income to the investors throughout the life of the producing properties. Of course, there are many variations to this concept depending upon which fund we are talking about, how they operate, their charges, reinvestment options, etc., but basically the majority of funds do provide a future income means for the investor's dollar as well as providing the fund's managing or operating company with a sound base in the oil and gas business. Even though I am working for a company operating an income fund I might add that my main objection to these Limited Partnership Income Funds is that too many small investors are encouraged to participate. I am still old-fashioned enough to believe that even though the purchase of producing oil and gas properties is a safe and sound investment there is enough risk involved that it is not a place for "widows and orphans" or people depending on this income for their everyday to day existence to invest their money. However, it is a good place for a larger, more sophisticated investor to place his money in a relatively sound investment providing future income with some degree of tax shelter.

I didn't mean to get into a dissertation on income funds and I intend to only talk about one income fund, that one being my "bread and butter", Ada Oil Company, and our outlook for buying production. If a poll could be taken we would undoubtedly find that each of the above-mentioned five categories have discovered that in order to buy production in today's market they have had to be in what I have referred to as the "buying mood". Further, of the above categories of companies the income funds have bought the majority of properties with-in the past few years. We at Ada Oil Company have purchased our share of these properties. Since June 1, 1972 we have purchased or participated in the purchase of over $27,000,000 worth of producing oil and gas properties. These properties were purchased from a total of 19 companies or individuals and were located in over 45 separate producing oil and gas fields containing a total of 374 producing oil and gas wells. In addition to being in the "buying mood" we utilize what I consider a further technical as well as psychological advantage of "packaging" groups of producing properties and/or fields for individual purchases by our various partnerships. In order to buy any of these
properties we have had to include in our evaluation our best estimate for future oil and gas price increases. We have also looked at the various other "plus" factors that I have referred to with regard to the reserves estimated and their classification. We are a buying company and we look for the technically sound reasons, if they exist, to buy production and not for the reasons not to buy.

There has been a great deal said, negatively, recently as to what the increase in loan interest rates over the past several months has done to the purchase price that can be paid for oil and gas production. There is also additional negative talk that future operating cost increases will either exceed or equal the future oil and gas price increases. If any of you gentlemen believe that either of these cases are true, you are not going to buy oil and gas production. For example, our first income fund purchase made during June, 1972, assumed that the price of oil would increase from the then high price of $3.42 per barrel to $4.50 per barrel over a period of three years. We are now getting $4.35 per barrel for oil produced in that field and $5.50 per barrel for its "new" oil. The new oil is as defined under the recent Cost of Living Council definition. Although the definition is complicated, suffice to say, we as well as other operators have had success in gaining this classification. As a further example, one of our first purchases considered new gas being sold in the future for the then, then being a little over a year ago, unheard of price of 45¢ per Mcf. Similar "new" gas in that area is now being sold for 65¢ to 75¢ per Mcf with a nearby gas contract being 99¢ per Mcf -- no I did not make a mistake, that is a fact -- 99¢ per Mcf! As you can see these price increases have more than exceeded the slight increase in operating expenses over this same period of time. I am not saying that this will continue but it is a condition that exists in our industry today and in order to buy production we are going to have to properly estimate or perhaps a better word would be "guessimate" what future product prices will be. If we do not properly guesstimate these increases, we will not buy production.

To show the effects of loan interest rate increases inherent to borrowing or "leveraging" as well as showing the effect of estimated price increases and, further, also showing our secrets, Tables 1 through 3, and 1-A through 3-A, show what we refer to as our "bank loan calculations". These are a summary of an actual purchase of a group or "package" of properties for a specific Ada Income Fund Partnership. Directly under the heading and to the left is shown and estimate of tangible and intangible costs applicable to future development work as well as estimated capitalized costs all of which were utilized for federal income tax calculations. Directly below and to the right of the heading are shown the actual purchase price of the properties, the amount of our bank loan, its respective loan to purchase ratio, the effective loan interest rate and the discount rate utilized for evaluation purposes that we applied to the future cash flow. Below these factors are shown the future yearly projections of gross income, operating expenses, principal on bank loans, interest on bank loans, the depreciation basis used for calculating federal income tax, the depletion allowance with the number to the right of it indicating what type of depletion method we utilized. The number "3" under the heading "T" indicates a cost depletion option. This was the most favorable option to us in this case. The next columns show the taxable income, the federal income tax that would be paid by an investor in the 50% tax bracket, the cash flow before income tax and the cash flow after income tax. Directly below the projections is our appraisal summary showing the investor's return on investment, discounted cash flow at 7%, rate of return on investment and payout time for investment based both upon the total purchase price paid and not including any effects of financing or "leveraging" as well as based only upon the actual equity dollars invested in the purchase. The results of these criteria are summarized both before and after federal income tax for each case.

As shown on these projections, we borrow about 60% of the purchase price for the oil and gas income fund purchases. This is done so as to obtain a proper "leverage" factor necessary for competitive bidding as well as
to tailor a bank repayment schedule that will allow for some cash flow during the years of loan debt repayment. In order to have the "buying mood" and the proper approach our offer price is, of course, based upon our actual equity dollars only, or in this case the $610,000 investment, and not the total purchase price of $1,525,000. Here again, if your considerations are not based upon similar criteria you are going to experience difficulty in buying production. Tables 1, 2 and 3 show the effect of the various increases in loan interest rates that we have experienced. The loan interest rates shown are the effective rate or the amount that we as a borrower have paid for these transactions. I might add that we, as most companies, are borrowing on a "floating" interest basis which we did not attempt to build into our computer program but we are showing in Tables 3 and 3-A what is possibly a good average effective interest rate for the next four to five years. Tables 1, 2 and 3 represent our appraisal with our best estimate of the future oil and gas price increases applicable to the subject properties. As you can see in Table 1 shows this appraisal utilizing the unheard of interest rate of 6% that we experienced a little over a year ago while Table 3 shows this appraisal with an average interest rate of 8.75%. Table 2 shows the appraisal with what we are now paying on recent borrowings or an effective interest rate of 11%. As you can see, each of these examples represent what I am sure any of us would consider a "good trade". The estimated future oil and gas price increases more than offset the effects of loan interest rate increases.

Tables 1-A, 2-A and 3-A show this same projection based upon the same technically sound reserves and cost data and the same applicable effective interest rates but, in each case, assumes little or no future price increases for the products. Table 2-A indicates that perhaps we are stretching our purchase price somewhat when considering the 11% effective interest rate. However, again based upon the actual equity dollar investment it is probably a trade that most of us would consider. This is especially so when we look at Table 3-A as representing the most realistic case. However, Tables 1-A, 2-A and 3-A do not represent realistic positive and economically sound thinking insofar as future product prices are concerned.

The main point that these tables effectively show is that if we wanted to buy these properties, which we did, we had all the sound technical and economical justification required. There were apparent justifiable ways we could have talked ourselves out of these purchases. If we only considered Table 2-A and were unrealistically cautious in our engineering analysis we would not have made these purchases. Instead, we wanted to buy production. We made the soundest technical reservoir engineering and economic approach possible and decided to live by it. We were in the "buying mood" and wanted to buy production. We, therefore, utilized the best possible technical and psychological means at our disposal to accomplish this. We were not looking for negative factors that did not exist.

In conclusion, I am not trying to represent points and beliefs which may stray from a strong technical analysis of a purchase. This is still the primary consideration. Instead, I want to emphasize the point that in order to buy production we have to consider the psychological factors involved in the appraisal itself as well as in the normal confrontation or trade between the buyer and seller. In short, we have to be in the "buying mood" and properly appraise the reasons why we should buy and not overemphasize the factors of why we should not buy. These negative factors should be eliminated prior to a detailed analysis of the trade. However, if there are too many negatives present, don't pursue the trade. If, however, at that time it appears that you have a buyable prospect, and you have the financial ability as well as need and desire to buy, do your darnedest to do so. Get in the "buying mood".

Mr. Marvin C. Zeid was Vice President of Engineering with Ada Oil Company at the time of this presentation.
### Table 1

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
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<tbody>
<tr>
<td>Development Costs</td>
<td>$1,716,900</td>
</tr>
<tr>
<td>Personal Price</td>
<td>$5,125,000</td>
</tr>
<tr>
<td>Annual Payment</td>
<td>$137,875</td>
</tr>
<tr>
<td>Capitalized Cost</td>
<td>$242,300</td>
</tr>
<tr>
<td>Interest Rate</td>
<td>10.00%</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
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</table>

### Table 2

<table>
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<tr>
<th>Description</th>
<th>Amount</th>
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</thead>
<tbody>
<tr>
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<td>10.00%</td>
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</table>

### Table 3

<table>
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<th>Description</th>
<th>Amount</th>
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</thead>
<tbody>
<tr>
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<td>$242,300</td>
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<tr>
<td>Interest Rate</td>
<td>10.00%</td>
</tr>
</tbody>
</table>

**Note:** The tables and calculations are based on the data from the provided text and are presented in a readable format.
### Table 1-4
**Year Loan Calculation**

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
<th>Amount</th>
<th>Corrected Amount</th>
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</thead>
<tbody>
<tr>
<td><strong>Development Costs</strong></td>
<td><strong>Purchase Price</strong></td>
<td>$1,121,900</td>
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</tr>
<tr>
<td></td>
<td><strong>Amount of Loan</strong></td>
<td>$1,050,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Loan to Acquisition Ratio</strong></td>
<td>0.94</td>
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</tr>
<tr>
<td></td>
<td><strong>Interest Rate</strong></td>
<td>7.0%</td>
<td></td>
</tr>
</tbody>
</table>

| Short-Term Costs       | **Annual Rate**                                   | 0.0          |                 |
|                        | **Amount of Loan**                               | $60,000       |                 |
|                        | **Interest Rate**                                | 7.0%          |                 |

| Total                  | **Annual Rate**                                   | 0.0          |                 |
|                        | **Amount of Loan**                               | $1,110,000    |                 |
|                        | **Interest Rate**                                | 7.0%          |                 |

### Table 2-6
**Interest Payments**

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Amount</th>
<th>Corrected Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Interest Payable</strong></td>
<td><strong>Annual Rate</strong></td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Amount of Loan</strong></td>
<td>$60,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Interest Rate</strong></td>
<td>7.0%</td>
<td></td>
</tr>
</tbody>
</table>

| Total                  | **Annual Rate**                                   | 0.0          |                 |
|                        | **Amount of Loan**                               | $1,110,000    |                 |
|                        | **Interest Rate**                                | 7.0%          |                 |

### Table 3-4
**Year Loan Calculation**

<table>
<thead>
<tr>
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<tr>
<td></td>
<td><strong>Interest Rate</strong></td>
<td>7.0%</td>
<td></td>
</tr>
</tbody>
</table>

| Short-Term Costs       | **Annual Rate**                                   | 0.0          |                 |
|                        | **Amount of Loan**                               | $60,000       |                 |
|                        | **Interest Rate**                                | 7.0%          |                 |

| Total                  | **Annual Rate**                                   | 0.0          |                 |
|                        | **Amount of Loan**                               | $1,110,000    |                 |
|                        | **Interest Rate**                                | 7.0%          |                 |

### Table 4-6
**Interest Payments**

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Amount</th>
<th>Corrected Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Interest Payable</strong></td>
<td><strong>Annual Rate</strong></td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Amount of Loan</strong></td>
<td>$60,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Interest Rate</strong></td>
<td>7.0%</td>
<td></td>
</tr>
</tbody>
</table>

| Total                  | **Annual Rate**                                   | 0.0          |                 |
|                        | **Amount of Loan**                               | $1,110,000    |                 |
|                        | **Interest Rate**                                | 7.0%          |                 |

---

**Special Note**

- Some text sections are marked as "Special Note" which are not included in the tables.
- The calculations and tables provided are based on the assumption that all interest payments are paid within the year.
WHAT'S THE PRICE OF MY CRUDE OIL?

By John R. Brack, Acquisitions, Universal Resources Corporation
1000 Carillon Tower East, Dallas, Texas 75240

Presented at the Eleventh Annual Meeting of
The Society of Petroleum Evaluation Engineers
Mexico City, November 1973

It is a pleasure to take an active part in this conference. I thank you and our program chairman for the invitation.

My topic is a status report on domestic crude oil pricing. It is in the present tense meaning it is not a forecast of future prices.

Domestic crude oil producers, along with most of the U.S. economy, are subject to price regulations administered by the Cost of Living Council. The CLC issued Phase IV regulations August 17, 1973, containing a two-tier price structure. Old oil is limited to a maximum 35¢/bbl more than the top price in effect on May 15, 1973. New oil, and an equal volume of released oil, is exempt from direct regulation. There is no longer any limitation on the amount of crude which may be imported. There is a fee (13¢/bbl) in lieu of a tariff.

An interesting reversal of roles was accomplished by the bureaucrats who declared the producer to be the one who established crude prices, while the pipeline and crude purchasing companies (who have heretofore issued crude price bulletins) were simply responding to the market.

Texas Pacific Oil Company took the CLC at their word and announced that TP was posting a price of $1.00/bbl above the May 15 price for the new oil. The industry generally accepted a premium of $1.00/bbl for September. Exxon increased the premium to $1.65/bbl retroactively to October. Now the industry expects $2.00/bbl starting November, 1973. If it occurs, old oil will be about $4.20/bbl, while new and released oil will command $6.20/bbl.

I've put off about as long as I can getting into the definition of crude for pricing purposes. There are three types: old, new, and released. Old crude is the volume produced and sold during a particular month for a particular property. For properties more than 12 months old, it is the volume produced and sold during the same month one year ago. If the property produced less than a full twelve months, it is the total production divided by 12. This volume is defined as the "Base Production Control Level".

New oil is the volume in excess of the base production control level.

Released oil is a bonus volume equal to the new oil volume.

As we said, old oil is limited in price to the May 15, 1973 price, plus no more than 35¢.

New and released oil is free to find its market level.

And that brings us to the real story. Apparently the market place has affirmed a crude price in the order of $5.25/bbl. Naturally, there are variations from this price depending on location and refinery volume, efficiency and market. Nevertheless, $5.25 is taken as a representative market value for crude.

Faced with control in the range of $4.20 for 40° sweet, the new and released crude can be priced at whatever it takes to result in an average of $5.25 for the sum total old, new and released crude. For example, take a lease making 1000 barrels per month. Let the stable production be 990 barrels with 100 new barrels resulting from re-stimulation. There will be 100 new
and 100 released, leaving 800 old barrels. Now is the old sold at $4.20, then the 200 new and released oil would be priced at $9.45/bbl to result in $5.25/bbl average. This is the origin of some of the screaming headlines.

Many ingeneous ways have been implemented to achieve this average price. Pre-payments, service charges, barter and resale of products are among the legal ones. There has developed a black market among consumers on the fringe of the industry, such as trucking companies, rig movers, etc.

Inexco announced a deal with Gulf Oil covering 6 million barrels of Hilight crude. Gulf paid $30,000,000 which will be recovered over about 6 years. Using nominal value of money at 10% means this crude was sold for $6.55/bbl or $1.19 above the 'new' price of $5.36. It is also $1.55/bbl above the weighted average price. The pre-payment is secured by Inexco's Hilight production estimated at 5,820,000 net bbls (according to Lewis Engineering). Gulf has the option to purchase "any and all other crude" at a defined "free market price" (definition not provided by Inexco) calculated on the average of crude from Saudi Arabia, Kuwait and Nigeria.

There is a story that LVO Company, Tulsa, has given a call on its nationwide production to OKC Corporation of Dallas. The plan reportedly allows OKC to sever existing connections as they get around to it. Prices will average an unspecified premium above major company posting. Obviously, this allows "high grading" by OKC. There are no published reports on the LVO/OKC deal, but sufficient unconfirmed stories are circulating to make me rely on the main thread of the transaction.

Some operators are charging for services, such as checking pipeline gaugers, repairing lease roads and filing reports. Others are selling part of their crude under old prices, but taking a negotiated volume down stream at the refinery, which volume is then used to exchange for services such as drilling and trucking.

The State of New Mexico has contracted with a local refiner to sell all the state royalty oil which will be taken in kind. Operators in Kansas and Oklahoma have organized a selling co-op into which each assigns his production to be sold under advantageous prices. U.S. Department of Interior is offering 8500 B/D royalty oil in Wyoming, (heretofore sold by the operator) to any buyer. State of Texas wants royalty oil in kind. U.T.Lands is looking into the same deal.

Where does this fit into the work of the evaluation engineer? Well, there was a day when evaluations were based on current prices, accompanied by an alternate calculation using escalated prices as per the clients' wishes. Now the problem is to tie down what current prices are. The most exciting file you can own is a collection of price bulletins.

Because crude payments are received 45 to 60 days after actual production, company accountants can not document current prices being paid. Purchasers have followed a wide variety of practices for making payment. Some calculate the new oil volume and make prompt payment. Others pay all volumes at the lower price and expect the producer to claim the higher prices. Others make one payment at the low price and in the following month add a supplemental amount for the new oil. All purchasers require the seller to sign a statement declaring the seller to be in compliance with Phase IV.

Some attitudes are changing among buyers. For example, when Amoco refused a request by Kerr-McGee to exchange crude in transit, Kerr-McGee took the unprecedented step of exercising their rights under the Common Carrier law, compelling Amoco to ship the oil being paid the regular transportation tariff. In a similar change of attitude, Conoco waived gravity penalties, but had to restore them when the May 15 critical date was revived.

In a situation of flux any conclusions are at best temporary. From an engineering viewpoint it has become important to go into the details of each transaction to determine the current price of a specific barrel of crude. So what is the price of crude oil? Sorry, I don't know.
Subsidiary equation is new approach

THE SUBSIDIARY equation provides a new approach for determining oil saturation in a reservoir at any pressure during the reservoir's history.

This information leads directly to the oil recovery at any period of production, using only a desk calculator.

The subsidiary equation is derived from the simultaneous treatment of the basic diffusivity equations for oil and gas released from solution within the reservoir, with both flowing to the well. The fundamental data used are relative permeabilities and PVT data.

Three example fields are covered in this article to show results under different formation characteristics. In each case, the oil saturation is shown at various stages as reservoir pressure is lowered.

The significance of the subsidiary equation is that it permits the application of the oil equation alone to determine pressure as a function of radius with time. This is transient fluid flow for two-phase fluid movement.

The gas is accounted for by the balance between the oil and gas produced to equal the oil and gas voided in the pore spaces of the formation.

This article is an outgrowth of work done for an international oil company. The assignment was to determine the residual oil saturations in place in old and depleted oil fields for which no production records were available.

This article is divided into two parts. The second part will appear in next week's Journal.

Subsidiary equation. The subsidiary equation is derived from a mass balance of fluid movement in the reservoir pore space.

This is the diffusivity equation for the voidage of oil in its flow to the well bore joined with the comparable equation for the gas released from solution as formation pressure drops. This gas in turn fills the space voided by the oil.

These complex conditions are related in fairly simple forms of the diffusivity equations by the use of exponential expressions for densities of oil and gas. The pressure gradients that propel the fluids to the well cancel out between these two diffusivity equations, leaving the oil saturation as an explicit function of reservoir pressure.

This results in a nonlinear differential equation between these two variables that is readily solved as illustrated by later examples.

The starting point in these proceedings is the equation of continuity given in Lamb. This has been the basis for the first paper published on transient flow, and applies for multiphase fluid flow.

The author...

William Hurst is a petroleum reservoir engineering consultant in Houston, operating his own firm since 1949. Before that he was with Shell Oil Co. for 6 years as senior staff reservoir engineer, with Core Laboratories Inc., Dallas, as a consultant, and for 13 years with Humble Oil & Refining Co. (now Exxon). Hurst is active in the Society of Petroleum Engineers of AIME and in the Society of Petroleum Evaluation Engineers. He received the Anthony F. Lucas Gold Medal Award from AIME in 1964.

The equation of continuity can be simply expressed as

\[
\frac{\partial(\rho u)}{\partial x} + \frac{\partial(\rho v)}{\partial y} = -\varphi(1-S_o) \frac{\partial \rho}{\partial t}
\]  

(1)

where \( \rho \) is the density of the fluid and \( u \) and \( v \) are the corresponding velocities along the respective coordinates, with \( t \), time.

Wherever possible, AIME symbols will be used in this article.

In the early paper an exponential relationship was used for the density of the fluid. This simplified the mathematics that permitted density and then pressure to be expressed as a function of radius and time.

This procedure is again adopted, so for the gas, this expression is

\[
\rho_g = \rho_0 e^{-C_g(\theta - \varphi)}
\]

(2)

and for the oil, it is

\[
\rho_o = \rho_0 e^{-C_o(\theta - \varphi)}
\]

(3)

Equations 2 and 3 show that lowering reservoir pressure decreases gas density and increases oil density.

The increase in oil density comes with the release of gas from solution and will be shown graphically later.

Although reference is made to a fixed condition, in actual application the compressibilities, \( C_o \) and \( C_g \), are undergoing change with the change in reservoir pressure.

Differentiating Equations 2 and 3 gives expressions that lend themselves readily to the equation of continuity. Thus,

\[
\frac{\partial \rho_o}{\partial \tau} = c_z \rho_o \frac{\partial \rho}{\partial \tau}
\]

(4)
for finding reservoir oil saturation — 1

and

$$\frac{\partial p_o}{\partial t} = -c_0 \rho_o \frac{\partial p}{\partial r}$$  \hspace{1cm} (5)

Using Equation 1, expressed for oil and radial flow, and introducing Darcy's law as it pertains to relative permeability and the flow of oil,

$$u_o = \frac{k_o}{\mu_o} \frac{\partial p}{\partial r}$$  \hspace{1cm} (6)

we get

$$\frac{1}{r} \frac{\partial}{\partial r} \left( \frac{r}{\partial p} \frac{\partial p}{\partial r} \right) = \varphi \frac{\mu_o}{k_o} \frac{\partial (S_o \rho_o)}{\partial t}$$  \hspace{1cm} (7)

Equation 7 is a weight balance for oil in the reservoir pore spaces. This equation introduces the oil saturation, $S_o$, associated with time, $t$, representative of the total pore space that must be accounted for as oil is produced. $S_o$ is the reservoir property we wish to determine in this study.

Therefore,

$$\frac{1}{r} \frac{\partial}{\partial r} \left( \frac{r}{\partial p} \frac{\partial p}{\partial r} \right) = -c_o \varphi \frac{\mu_o}{k_o} \frac{\partial (S_o \rho_o)}{\partial t}$$  \hspace{1cm} (8)

and

$$\frac{\partial^2 \rho_o}{\partial r^2} + \frac{1}{r} \frac{\partial \rho_o}{\partial r} = -c_o \varphi \frac{\mu_o}{k_o} \frac{\partial (S_o \rho_o)}{\partial t}$$  \hspace{1cm} (9)

Expressing the left-hand side of Equation 9 in terms of pressure, and recalling Equation 5,

$$\frac{\partial^2 \rho_o}{\partial r^2} = c_o \rho_o \frac{\partial p}{\partial r} - c_o \rho_o \frac{\partial \rho_o}{\partial r^2}$$  \hspace{1cm} (10)

since $C_o$ is small, Equation 9 simplifies to

$$\frac{\partial^2 \rho_o}{\partial r^2} + \frac{1}{r} \frac{\partial \rho_o}{\partial r} = \varphi \frac{\mu_o}{k_o} \frac{\partial (S_o \rho_o)}{\partial t}$$  \hspace{1cm} (11)

Differentiation of the right-hand side of Equation 11 in terms of pressure, yields

$$\frac{\partial (S_o \rho_o)}{\partial t} = \left( -S_o c_o \rho_o + \rho_o \frac{\partial S_o}{\partial p} \right) \frac{\partial p}{\partial t}$$

and

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \varphi \frac{\mu_o}{k_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - \frac{\partial p}{\partial t} \right)$$  \hspace{1cm} (12)

In a similar manner, using Darcy's Law for relative permeability and flow of gas

$$u_g = \frac{k_g}{\mu_g} \frac{\partial p}{\partial r}$$  \hspace{1cm} (13)

Combined with the equation of continuity as in development of Equation 7, we get

$$\frac{1}{r} \frac{\partial}{\partial r} \left( \frac{r}{\partial p} \frac{\partial p}{\partial r} \right) = \varphi \frac{\mu_g}{k_g} \frac{\partial (S_g \rho_g - S_g \gamma_g)}{\partial t}$$  \hspace{1cm} (14)

where, $S_g$ is the gas saturation in the interstices, and $\gamma_g$ is the weight of gas liberated from solution per volume of oil at reservoir conditions determined from PVT analysis.

Since this is gas that is added, and separate from the depletion within the gas space that is being voided of gas, it is negative.

Performing the calculations performed earlier for oil, then

$$\frac{\partial^2 \rho_g}{\partial r^2} + \frac{1}{r} \frac{\partial \rho_g}{\partial r} = c_g \varphi \frac{\mu_g}{k_g} \frac{\partial (S_g \rho_g - S_g \gamma_g)}{\partial t}$$  \hspace{1cm} (15)

Expressing the left-hand side of Equation 15 in terms of pressure,

$$\frac{\partial^2 \rho_g}{\partial r^2} = \rho_g c_g \frac{\partial p}{\partial r} + \rho_g c_g \frac{\partial^2 p}{\partial r^2}$$  \hspace{1cm} (16)

and recalling Equation 4,

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \frac{\varphi \mu_g}{k_g} \frac{\partial (S_g \rho_g - S_g \gamma_g)}{\partial t}$$  \hspace{1cm} (17)

where $C_g$ is small.

Differentiation of the right of Equation 17 in terms of pressure, yields,
How saturation changes with pressure

\[
\frac{\partial (S_o \rho_e - S_o \gamma_e)}{\partial t} = \left( \frac{\partial S_o}{\partial p} + \rho_e \frac{\partial \gamma_e}{\partial p} - S_o \frac{\partial \gamma_e}{\partial p} - \gamma_e \frac{\partial S_o}{\partial p} \right) \frac{\partial p}{\partial t} =
\]

\[
\left( c_e S_o \rho_e + \rho_e \frac{\partial S_o}{\partial p} - S_o \frac{\partial \gamma_e}{\partial p} - \gamma_e \frac{\partial S_o}{\partial p} \right) \frac{\partial p}{\partial t}
\]

Therefore, what is involved in Equation 17 is

\[\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \]

\[\varphi \frac{\mu_e c_s}{k_o} \times \left( \frac{S_o + \frac{1}{c_e} \frac{\partial S_o}{\partial p} - S_o \frac{\partial \gamma_e}{\partial p} - \gamma_e \frac{\partial S_o}{\partial p}}{c_e \rho_e \frac{\partial p}{\partial p} + c_e \rho_e \frac{\partial \gamma_e}{\partial p} - \gamma_e \frac{\partial S_o}{\partial p}} \right) \frac{\partial p}{\partial t}
\]

Equating the right-hand sides of Equations 12 and 17,

\[\varphi \frac{\mu_e c_s}{k_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right) = \]

\[\varphi \frac{\mu_e c_s}{k_o} \left( 1 - S_w - S_o - \frac{1}{c_e} \frac{\partial S_o}{\partial p} - S_o \frac{\partial \gamma_e}{\partial p} - \gamma_e \frac{\partial S_o}{\partial p} \right)
\]

where \( S_e = 1 - S_w - S_o \); and \( \frac{\partial S_o}{\partial p} = -\frac{\partial S_e}{\partial p} \).

Further, let

\[f(S_o) = \frac{\mu_e c_s \rho_e k_o}{\mu_e c_s \rho_e k_o}
\]

This is a function of reservoir pressure and oil saturation as expressed through Equations 12 and 19 as instantaneous diffusivity equations, representative of the coefficients.

Thus

\[f(S_o) \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right) = \]

\[\left( 1 - S_w - S_o - \frac{1}{c_e} \frac{\partial S_o}{\partial p} - S_o \frac{\partial \gamma_e}{\partial p} - \gamma_e \frac{\partial S_o}{\partial p} \right)
\]

Solving for \( \frac{\partial S_o}{\partial p} \) that appears in the relation, we have

\[\frac{\partial S_o}{\partial p} = \left[ \frac{f(S_o) - 1}{c_o - \frac{1}{c_o} \frac{\partial \gamma_e}{\partial p}} \right] \frac{1}{c_o} \frac{\partial S_o}{\partial p} + \frac{1}{c_e} \frac{\partial S_o}{\partial p}
\]

\[\frac{\partial S_o}{\partial p} = \left[ \frac{f(S_o) - 1}{c_e \rho_e \frac{\partial p}{\partial p}} \right] \frac{1}{c_e \rho_e \frac{\partial p}{\partial p}} \frac{\partial S_o}{\partial p} + \frac{1}{c_e \rho_e \frac{\partial p}{\partial p}} \frac{\partial S_o}{\partial p}
\]

The integration of this formula from the initial reservoir pressure, \( P_o \), and oil saturation, \( 1 - S_w \), to a lower pressure condition, yields

\[S_o = 1 + S_w = \left[ \frac{P}{1 + S_w} \right] \frac{\partial S_o}{\partial p} + \frac{1}{c_e \rho_e \frac{\partial p}{\partial p}} \frac{\partial S_o}{\partial p} + \frac{1}{c_e \rho_e \frac{\partial p}{\partial p}} \frac{\partial S_o}{\partial p}
\]

where \( P \leq P_o \), and \( S_o \) is the resulting oil saturation at this lowered pressure.

The fact that \( S_o \) is also contained within the integrand offers no complication in the solution of Equation 24, recognized as a nonlinear differential equation.

The procedure used to determine \( S_o \) in this formula is to assume a linear variation between \( S_o \) and reservoir pressure, \( P \). The choice for \( S_o \) at the lower abandonment
pressure is arbitrary.

Using the chosen value of \( S_o \), in the integrand of Equation 24 gives a calculated value for \( S_o \).

The average of the assumed and calculated \( S_o \) values is the basis for the next assumed value for \( S_o \) in the formula. This usually requires four repetitive calculations to give a rapid convergence for oil saturation vs. pressure.

Application. Figs. 1, 2, and 3, show oil saturations in place vs. pressure for the fields considered in this paper and developed from the mathematics.

The first, the Hilgate Area, Campbell County, Wyo., was the test case to determine if the method applied.

This field was chosen because the physical data were at hand, the field is a major producer, and the author had been involved in its early discovery.3

The reservoir is the Muddy formation at 9,000 ft, with a connate water content of 19% to give an initial oil saturation of 81% shown on the plot.

This is a typical high-pressure field, undersaturated with gas at the beginning, with a gas-oil ratio of 1,310 cu ft/bbl.

The remaining two cases are developed from post-mortem data on Fields A and B. These are old, depleted oil fields produced at the turn of the century for which no information is available.

The procedure was straightforward to acquire the necessary data for this study.

Representative core samples were sent to Core Laboratories Inc. of Dallas for relative permeability determination. Results are shown in Figs. 5 and 6 for Field A.

The PVT analysis was performed by PVT Laboratories Inc. of Houston.

The instructions to this laboratory were to reconstruct the PVT analysis by charging a representative sample of the crude from the field with gas to reach an initial saturation pressure of 434 psia for Field A. Some of these data are shown in Fig. 4, but most are reported in table form.

For the higher pressure of Field B, the PVT analysis for Field A was extrapolated for this increase in pressure by methods used in material-balance studies which will be discussed later.

### Table 1

<table>
<thead>
<tr>
<th>( P, ) psia</th>
<th>( \rho_o, ) g/cc</th>
<th>( \Delta )</th>
<th>( \Delta^2 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>434</td>
<td>0.8339</td>
<td>-1.47058 \times 10^{-5}</td>
<td>+5.24455 \times 10^{-7}</td>
</tr>
<tr>
<td>400</td>
<td>0.8344</td>
<td>-2.60000 \times 10^{-5}</td>
<td>-0.40000 \times 10^{-7}</td>
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<td>0.8357</td>
<td>-2.20000 \times 10^{-5}</td>
<td>+0.40000 \times 10^{-7}</td>
</tr>
<tr>
<td>300</td>
<td>0.8368</td>
<td>-2.60000 \times 10^{-5}</td>
<td>+0.40000 \times 10^{-7}</td>
</tr>
<tr>
<td>250</td>
<td>0.8381</td>
<td>-3.00000 \times 10^{-5}</td>
<td>+0.40000 \times 10^{-7}</td>
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<tr>
<td>200</td>
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<td>-3.20000 \times 10^{-5}</td>
<td>+0.20000 \times 10^{-7}</td>
</tr>
<tr>
<td>150</td>
<td>0.8412</td>
<td>-3.40000 \times 10^{-5}</td>
<td>+0.40000 \times 10^{-7}</td>
</tr>
<tr>
<td>100</td>
<td>0.8429</td>
<td>-3.80000 \times 10^{-5}</td>
<td>+0.40000 \times 10^{-7}</td>
</tr>
<tr>
<td>50</td>
<td>0.8448</td>
<td>-2.26628 \times 10^{-5}</td>
<td>-1.79803 \times 10^{-7}</td>
</tr>
</tbody>
</table>

Divided differences  
\( \zeta = 0.975, \ p = 423.2 \) psia

Interpolation,
\[
\rho_o = 0.8339 + (423.2 - 434) (-1.47058) \times 10^{-5} + (423.2 - 434) (423.2 - 400) (1.34455) \times 10^{-7}
\]
\[= 0.83403 \text{ g/cc} \]

Differentiation,
\[
\frac{d\rho_o}{dp} = -1.47058 \times 10^{-5} + (423.2 - 434) (1.34455) \times 10^{-7}
\]
\[= -1.30385 \times 10^{-5} \]

Oil Compressibility, Equation 29
\[
c_o = \frac{-1 (-1.30385) \times 10^{-5}}{0.83403}
\]
\[= 1.56331 \times 10^{-5} \text{ vol/vol/psi} \]
### Physical data, Field A

<table>
<thead>
<tr>
<th>( \ell )</th>
<th>( \rho_s )</th>
<th>( \gamma_s )</th>
<th>( \frac{\partial \gamma_s}{\partial p_s} )</th>
<th>( \rho_o )</th>
<th>( C_{w_s} )</th>
<th>( \rho_v )</th>
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</thead>
<tbody>
<tr>
<td>1.805</td>
<td>434.0</td>
<td>0.000090(10)^{-3}</td>
<td>-1.85084(10)^{-5}</td>
<td>0.83200</td>
<td>1.2152(10)^{-5}</td>
<td>31.62(10)^{-5}</td>
</tr>
<tr>
<td>0.975</td>
<td>423.2</td>
<td>0.02164</td>
<td>-1.89811</td>
<td>0.89603</td>
<td>1.56331</td>
<td>30.376</td>
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<tr>
<td>0.950</td>
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<tr>
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<td>0.85642</td>
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<td>3.20456</td>
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<tr>
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<tr>
<td>0.800</td>
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<td>5.62610</td>
<td>20.948</td>
</tr>
<tr>
<td>0.750</td>
<td>303.8</td>
<td>2.8420</td>
<td>-2.34307</td>
<td>0.83671</td>
<td>2.30304</td>
<td>19.182</td>
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<td>0.700</td>
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<td>17.522</td>
</tr>
<tr>
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<td>3.6444</td>
<td>-2.7132</td>
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<td>15.928</td>
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<tr>
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<td>238.7</td>
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<td>14.400</td>
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<td>65.1</td>
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<td>0.050</td>
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<td>11.701</td>
<td>-5.6539</td>
<td>0.8560</td>
<td>1.92949</td>
<td>0.84709</td>
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<tr>
<td>0.000</td>
<td>14.7</td>
<td>11.701</td>
<td>-5.6539</td>
<td>0.8560</td>
<td>1.92949</td>
<td>0.84709</td>
</tr>
</tbody>
</table>

The core analysis and relative permeabilities for Field B are separate from Field A, although not reported in this presentation.

Based on these data, and the application of Equation 24, the graphs shown in Figs. 2 and 3 were developed.

Likewise shown are the recoveries of oil originally in place for each lowering in reservoir pressure. This is expressed by the relation

\[
\% \text{ recovery} = \frac{S_{oil}B_{oil} - S_{w}B_{w}}{S_{oil}B_{oil}} \times 100
\]  

(25)

that accounts for the oil voided by the changes in oil saturation.

Thus for Fig. 2 the recovery at atmospheric pressure is 14.9% and for Fig. 3 is 16.1%. These are compatible with recoveries reported for analogous fields.

The mechanics of calculating Equation 24 show that the PVT data are most significant while relative permeabilities, Fig. 5, play a minor role.

**Physical data.** PVT data are known and have been used by those who have conducted material-balance studies in the past. Therefore, no detailed discussion will be entered upon here except to refer to terms used in the subsidiary equation that are different from the usual application of PVT data.

For a comprehensive understanding of the subject, the reader is referred to an excellent text by Amyx et al.4

Two essential phenomena are reported in PVT analyses, flash liberation and differential liberation.

Flash liberation is a measurement of the composite volumes of gas liberated from solution and its associated oil.

Differential liberation refers only to this saturated oil volume at reservoir conditions.

The difference between these two is the volume of gas liberated.

This is the application that has been used to determine \( \gamma_s \) in the subsidiary equation that expresses the weight of gas liberated from solution per unit volume of oil.

With reference to the Hilight field, flash liberation is expressed by the correlation developed by S. E. Buckley.

\[
y = \frac{(p_b - p)}{p \Delta V}
\]  

(26)

where \( \Delta V \) is the incremental volume increase of these composite mixtures and referred to a unit volume of oil at saturation pressure.

The differential liberation in turn is expressed by the relationship established by William Hurst, where

\[
\log \Delta V = a + b \log (p_b - p)
\]  

(27)

and \( \Delta V \) is the decrease in oil volume from saturation pressure, also referred to a unit volume of oil at the bubble-point pressure.

Thus, for the Hilight field, the ratio of \((V' - \bar{V})/\bar{V}\) is the volume of gas liberated from solution per unit volume of oil at reservoir conditions.

The gravity and correction factor for the liberated gas are available from the PVT analyses to permit determination of gas density. The product of these two factors is the \( \gamma_g \) term referred to in the subsidiary equation.

These correlations have also been used to extrapolate the PVT data for Field A to the higher pressure of Field B to find its \( \gamma_s \) values.

It is not always necessary to use these correlations. For Field A, density of gas liberated from solution, corrected to reservoir conditions, and the formation volume factor for its associated oil, yielded \( \gamma_g \).

Illustrations of the correlations mentioned for the

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THE OIL AND GAS JOURNAL—OCTOBER 8, 1973
Table 2

<table>
<thead>
<tr>
<th>p*</th>
<th>k*/k'</th>
<th>S*</th>
<th>∂S*/∂p*</th>
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</thead>
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<tr>
<td>5.28000</td>
<td>0</td>
<td>0.75000</td>
<td>4.35400 \times 10^{-4}</td>
</tr>
<tr>
<td>5.29400</td>
<td>0.00070</td>
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<td>5.31886</td>
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<td>5.34617</td>
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<td>7.00000</td>
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<td>0.64747</td>
<td>2.05980</td>
</tr>
</tbody>
</table>

\( \mu_0 = 0.010475 \) cp, Constant

Hilight field are given in a paper by Kennedy.\(^3\) Amyx et al.\(^4\) make further mention of these correlations, although neither author has published his results which each considered elementary although of importance in PVT analyses.

What is needed in Equation 24 is the rate of the change for each of these physical parameters with respect to pressure. This refers to \( \gamma_p \) and the instantaneous compressibilities for oil and gas obtained from their density relations described in Equations 4 and 5, namely

\[
c_p = \frac{1}{\rho_p} \frac{\partial \rho_p}{\partial p} \tag{28}\]

and

\[
c_o = -\frac{1}{\rho_o} \frac{\partial \rho_o}{\partial p} \tag{29}\]

To determine these differentials for the Hilight field, empirical curves were developed from the physical data. However, these were too time-consuming and did not yield a realistic interpretation of every inflection that could occur in the data.

Several attempts were made to find an acceptable method to interpolate and differentiate these data, including programming procedures. The search finally narrowed to the Method of Divided Differences as the most appropriate to this application. The reason for this is that the pressure changes in a PVT analysis are not necessarily equal but are those which are most convenient for the laboratory to report.

There is no reference to the Method of Divided Differences in the literature, so an illustrative example for Field A’s saturated oil density is shown in Table 1. This table also includes a sample calculation for the interpolation and differentiation for the oil compressibility given in Equation 29.

The first two columns of Table 1 show the density of the oil vs. reservoir pressure. This is laboratory data from the differential liberation, and it has been requested in all the PVT analyses used in this work.

The third column, expressed by \( \Delta \), is the ratio of the change of this oil density with respect to its pressure.

The fourth column, \( \Delta^2 \), is the rate of change in \( \Delta \), with respect to the overall pressure change that has occurred, and corresponds to a second-order differential, although expressed in increments.

Convenient pressure ratios (\( \zeta = 1.00, 0.975, 0.950, 0.900 \), etc.) were selected for use, not only in the subsidiary equation but as the range of pressure lowerings involved in the nonlinear differential flow equations for two-phase fluid flow that will follow. The example calculation in Table 1 uses \( \zeta = 0.975 \).

The arrows in this table indicate the directions that these interpolations can be used. Thus the pressure interval that \( \zeta \) refers to determines the values for \( \Delta \) and \( \Delta^2 \). The lower pressure range, the path can be reversed as shown by its arrow.

The results are given in Fig. 4, which illustrates the comparison of physical data with the values established by the Method of Divided Differences. It is to be observed that every inflection is faithfully reproduced from the PVT data.

Finally, the summarized data that include the calculated PVT values for Field A and its relative permeabilities are given in Table 2. The results are likewise listed, determined from Equation 24 to yield the oil saturation in situ versus the reservoir pressure illustrated in Fig. 2.

Application of the methods described here to numerical examples will be given in the second part of this article.

NOMENCLATURE

\( p \), density, \( \text{mL}^{-1} \)

\( \rho \), pressure, \( \text{mL}^{-1} \)

\( \zeta \), ratio of lowered to initial pressure, dimensionless

\( k \), permeability, \( \text{L}^2 \)

\( h \), net thickness, \( \text{L} \)

\( \phi \), porosity, fraction

\( \mu \), viscosity, \( \text{mL} \)

\( c \), compressibility, \( \text{L}^4 \)

\( S_0 \), oil saturation, fraction

\( S_w \), connate water, fraction

\( r \), radius, \( \text{L} \)

\( r_w \), well radius, \( \text{L} \)

\( r_e \), radius of external boundary, \( \text{L} \)

\( t \), absolute time, \( \text{t} \)

\( t_D \), dimensionless time, based on unit radius

\( B \), formation volume factor

\( R \), gas-oil ratio

SUBSCRIPTS

\( i \), initial condition

\( f \), subsequent condition

\( o \), oil

\( g \), gas

\( s \), solution gas

\( i \), flash liberation
Subsidiary equation is new approach for finding reservoir oil saturation—2

WILLIAM HURST
Petroleum Reservoir Engineer
Houston

A NUMERICAL example is given in this second part of a two-part article to demonstrate the application of mathematical techniques.

The subsidiary equation developed in the first part of this article is used to describe the flow of oil and gas within a reservoir as it moves toward a producing well. And the subsidiary equation reduces the complexity of this movement to mathematical solutions that can be performed on a desk calculator.

The explicit formulas involved can also be programmed for computer solution, but a small computer is sufficient for the work involved.

The numerical example will be given following a small amount of additional mathematical development.


In the first, "Interference Between Oil Fields," the series problem is presented for the variation in permeability to fluid flow. This is the extension of the Lord Kelvin solution[8] for a point source, but instead of a uniform medium, these variations are incorporated treating with the Laplace Transformations.

The second paper, "The Solution of Non-Linear Equations," recognizes that fluid characteristics as well as formation properties can vary. These variations are introduced for the nonlinear flow of gases in a formation as gas compressibilities change with reservoir pressure decline.

It is recognized that this is the dynamic condition for two-phase fluid flow; and instead of treating with two separate diffusivity equations, one equation for oil defines transient fluid flow, and the subsidiary equation is the relation between the oil and gas.

Thus Equation 9, that expresses the oil equation in terms of density, can be written as

\[
\frac{\partial^2 \rho_o}{\partial r^2} + \frac{1}{r} \frac{\partial \rho_o}{\partial r} = \varphi \frac{\mu_o}{k_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right) \frac{\partial \rho_o}{\partial t}
\]  

(30)

The relation for oil and gas liberated from solution is given by the dimensionless time in

\[
t_o = \frac{k_o}{\varphi \mu_o c_o \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right)}
\]  

(31)

per unit radius squared.

The subsidiary equation is now introduced in this formula to account for the changing oil saturation within the interstices.

The variation of the diffusivity constant with the lowered reservoir pressure in Equation 30 will be treated in the nonlinear flow formulas.

Another consideration is the proportional constant and the physical parameters associated with the oil rate that applies in these equations.

This refers to the \(q_o \mu_o / 4\pi k h\) term that the reader is familiar with in pressure buildup performance and to the basic treatment of the point-source solution by Lord Kelvin,[8] as well as the \(Q/2\pi t\) term given in the first paper.[6]

The point-source solution placed at the origin of a system, corresponding to Equation 30, is

\[
\frac{Q}{2\pi} = \frac{\delta \rho_o \delta x \delta y}{2\pi}
\]  

(32)

Introducing the pore volume,

\[
\frac{\varphi h Q}{2\pi} = \frac{\delta \rho_o \varphi h \delta x \delta y}{2\pi}
\]  

(33)

For the oil density \(\delta \rho_o = -C_{o1} \rho_{oi} \delta \rho_1\), and

\[
\frac{\varphi h Q}{2\pi} = \frac{C_{o1} \rho_{oi} \delta \rho_1 \delta x \delta y}{2\pi}
\]  

(34)

Further,

\[
\frac{1}{\rho_o} \frac{\partial (S_o \rho_o)}{\partial p} = \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o
\]  

(35)

and

\[
Q \frac{C_{o1} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right)}{\rho_o} \varphi h = \frac{\phi \delta \rho_1 \delta x \delta y}{2\pi}
\]  

(36)

therefore,

\[
\frac{Q}{2\pi} = \frac{C_{o1} \rho_{oi} q_{oi} \delta t}{2\pi h \varphi c_{oi} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right)}
\]  

(37)

where

\[
q_{oi} = \frac{\delta (S_o \rho_o)}{\delta t} \times \varphi \delta \rho_1 \delta x \delta y
\]  

(38)
is the rate of oil produced and voided at the point source.

Therefore, by the differentiation in Equation 30, relating absolute time with dimensionless time, we get

\[
dt_D = \frac{k_o \Phi}{\mu_o c_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right)
\]

(38)

and

\[
- \frac{Q}{2 \pi} = \frac{c_o \rho_o q_o \mu_o k_o h}{2 \pi k_o h} dt_D
\]

(39)

The differential with respect to dimensionless time leads to the integration of the Ed function of the Lord Kelvin solution, leaving the coefficient \(-C_n\ \rho_o \ q_o \ \mu_o / 2 \pi \ \kappa_o h\) as the rate relationship.

This is the comparable term developed earlier\(^6\) that now includes density; but here an accounting is made for the oil saturation in place that is identified with the voidage that will occur in the reservoir.

The negative sign reverses the order of the density relationship in the nonlinear flow equations since the oil density increases as reservoir pressure declines (Fig. 4).

When all these factors are incorporated, including the variables for the nonlinear flow of gases, then

\[
\rho - p_j = \frac{c_o \rho_o q_o \mu_o}{2 \pi k_o h} x \frac{1}{2} x
\]

\[
\left[ - E ( \left( \frac{- \frac{\phi \mu_o c_o}{k_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right) r_j^3}{4t} \right)^+ \right] + \\
E ( \left( \frac{- \frac{\phi \mu_o c_o}{k_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right) r_j^3}{4t} \right)^- )
\]

(40)

This represents the fluid movement in an infinite medium, subject to each increment of pressure drop in an areal traverse through the reservoir for a given time, with a constant rate of oil production.

This can be further simplified as expressed for pressure when we linearize the exponential relationship for the oil density in Equation 3.

Thus for the first pressure lowering from \(p_i\) to \(p_{i+1}\) using only the proportional terms involved in Equation 40

\[
(p_i - p_{i+1}) = q_{oi}
\]

(41)

For the second pressure lowering from \(p_{j+1}\) to \(p_j\), then

\[
(p_j - p_{j+1}) = c_{o(j+1)} \rho_o q_{oi}
\]

(42)

when expressed in densities.

Thus

\[
(p_{j+1} - p_j) = \frac{\rho_o q_{oi}}{c_{o(j+1)} \rho_o q_{oi}} = q_{o(j+1)}
\]

(43)

In Equation 43 it is accepted that the formation-volume factors for the oil are inversely proportional to the oil densities for the small changes in pressure encountered during the areal traverse of the reservoir.

For the pressure increment from \(p_j\) to \(p\), again expressed in densities, then

\[
(p - p_j) = c_j \rho_{o(j+1)} q_{o(j+1)}
\]

(44)

This reflects the constancy in \(Q\) that whatever changes have occurred at higher pressures will prevail to lower pressures, unless intermediate changes occur to effect subsequent terms, and

\[
(p - p_j) = \frac{p_{o(j+1)} q_{o(j+1)}}{p_{o(i)}}
\]

(45)

Therefore Equation 40, expressed in pressure, is the relationship

\[
p_j - p = \frac{q_{oi} \mu_o}{2 \pi k_o h} x \frac{1}{2} x
\]

\[
\left[ - E ( \left( \frac{- \frac{\phi \mu_o c_o}{k_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right) r_j^3}{4t} \right)^+ \right] + \\
E ( \left( \frac{- \frac{\phi \mu_o c_o}{k_o} \left( \frac{1}{c_o} \frac{\partial S_o}{\partial p} - S_o \right) r_j^3}{4t} \right)^- )
\]

(46)

This is the form used to solve two-phase fluid flow discussed in the numerical example to follow.

**Numerical example.** The results for Field A are shown in Fig. 8 for transient fluid flow, representing two-phase fluids—the oil and its liberated solution gas flowing in the reservoir toward the well.

Production and reservoir data for the field are given in Table 3. These are shown as two listings, one in \(f-p-s\) units, familiar to the reader, and the other in \(c-g-s\) units, required to conform with the definition for permeability in darcys.

The production rate assigned in the problem is 50 b/d, producing from a net sand thickness of 22.3 ft, with 5/16-in. casing set at top of the sand.

Initial well spacing was 3½ acres or less, but a spacing of 55 acres—exterior radius of 776.8 ft—is used in this example.

The permeability is 173 md, with the initial pressure of 434 psia, and the gas in solution is 76 scf/bbl.

The problem is the same as in the previously cited paper\(^7\) for gases; namely, that the areal traverses are established by pressure increments to determine radii for the absolute times of flow. For a fixed radius, such as at the well or the exterior boundary, these pressure increments are the independent variables that determine the times of pressure lowerings at these boundaries.

First, consider dimensionless time, \(t_{bo}\), given in Equation 31. To review briefly Figs. 1-3 show, by virtue of the subsidiary equation, a relationship between oil saturation and reservoir pressure.

**Table 3**

<table>
<thead>
<tr>
<th>(f-p-s) units</th>
<th>(c-g-s) units</th>
</tr>
</thead>
<tbody>
<tr>
<td>(q_o = 50 \text{ b/d} )</td>
<td>92.007 \text{ cc/sec}</td>
</tr>
<tr>
<td>(k_o = 173 \text{ md} )</td>
<td>0.173 \text{ darcys}</td>
</tr>
<tr>
<td>(h = 22.3 \text{ ft} )</td>
<td>679.704 \text{ cm}</td>
</tr>
<tr>
<td>(\phi = 19.5% )</td>
<td>0.195, \text{ fraction}</td>
</tr>
<tr>
<td>(S_w = 25% )</td>
<td>0.25, \text{ fraction}</td>
</tr>
<tr>
<td>(r_w = 2.75 \text{ in.} )</td>
<td>6.985 \text{ cm}</td>
</tr>
<tr>
<td>(r_e = 776.83298 \text{ ft} )</td>
<td>23,577.86329 \text{ cm}</td>
</tr>
</tbody>
</table>
PVT data for Field A

<table>
<thead>
<tr>
<th>( \xi )</th>
<th>( B_o )</th>
<th>( B_a )</th>
<th>( R_o )</th>
<th>( B_g )</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Vol. @ std. cond.</td>
<td>Vol. @ std. cond.</td>
<td>Vol. @ std. cond.</td>
<td>Vol. @ std. cond.</td>
</tr>
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<td>1.03500</td>
<td>0.031022</td>
<td>13.53613</td>
<td>1.03500</td>
</tr>
<tr>
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<td>1.03459</td>
<td>0.032004</td>
<td>13.32069</td>
<td>1.04529</td>
</tr>
<tr>
<td>0.950</td>
<td>1.03409</td>
<td>0.033034</td>
<td>13.09408</td>
<td>1.05642</td>
</tr>
<tr>
<td>0.900</td>
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</tr>
<tr>
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</tr>
<tr>
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</tr>
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<td>1.00797</td>
<td>1.02885</td>
<td>0</td>
<td>19.08462</td>
</tr>
</tbody>
</table>

and Fig. 7 shows its variation with time that reflects the pressure changes and the gas produced at the well.

The insert in this plot gives the total amount of gas produced for the final time shown in Fig. 8; namely, 35,216,888 cu ft of gas in 1,322.7 days.

The calculations for Equation 47 depend upon the PVT data listed in Table 4. Also shown are the formation volume factors for the flash liberation that will be used in the material-balance application that will follow. These are established from the correlations given in Equations 26 and 27.

The intermediate pressures at the well bore for their corresponding times to determine gas/oil ratios have been interpolated by the Lagrangian Interpolations\(^\text{11}\) using the data posted at the exterior radius and the calculated pressures at the well shown in Fig. 8.

Thus every inflection for gas/oil ratios illustrated in Fig. 7 are incorporated.

**Balance.** The accuracy of the results obtained in Fig. 8 for two-phase transient fluid flow must now be confirmed by the balance between the oil and gas produced at the well with the voidage of the oil and gas from the reservoir pore space. This refers to the last pressure gradient shown in Fig. 8 for 1,322.7 days.

The first part of the balance relates to the oil voidage within the interstices, and as such must be represented as a dynamic condition described by the diffusivity equation, Equation 11, as well as the derivation for the point-source solution in defining the rate of oil produced.

This expression for oil voidage for a given radius and the lowering of pressure from the initial conditions, is given by

\[
X_p = \frac{1}{B_o \rho_o} \frac{\partial S_o}{\partial p} \frac{dp}{h} \tag{48}
\]

or

\[
X_p = \frac{1}{B_o \rho_o} \frac{\partial S_o}{\partial p} \frac{dp}{h} - c_o \frac{S_o}{\rho_o} \tag{49}
\]

where the factors related to this integrand are given in Tables 2 and 4. The sign is negative as would apply for the direction of pressure lowering and voidage but will be omitted.

Applied to the reservoir as a whole and the sweep along the final pressure gradient shown in Fig. 8, the formula is

\[
N_p = \frac{\varphi h \times 2\pi}{159,000} \left[ \int_{r_w}^{r_o} X_p a \left[ \ln \left( \frac{r}{r_w} \right) \right] \right] \tag{50}
\]

where

\[
\varphi h = \frac{(0.195)(679.704)(2\pi)}{159,000} = 523.76707(10^{-3}) \tag{51}
\]

These factors are listed in Table 3, and 1 bbl equals 159,-000 cc.

Therefore,

\[
N_p = 523.76707(10^{-3}) \left[ \int_{r_w}^{r_o} X_p a \left[ \ln \left( \frac{r}{r_w} \right) \right] \right] \tag{52}
\]

and the results shown in the insert of Fig. 8, give 66,402.1 bbl of oil voided within the reservoir against 66,136.5 bbl of oil produced at the well in 1,322.7 days. This is an error of less than 0.5%.

To observe the gas produced from within the reservoir, the Schilthuis\(^\text{12}\) material-balance equation has been applied.

This is a static condition illustrated by its author, where the pressure in the formation is everywhere uniform, and decreases in this manner with the fluids produced, comparable to the lowering of liquid in an enclosed tank.

This situation is not indicated in Fig. 8 except as this pressure gradient can equalize in infinite time.

This can be computed from the volumetric equation for the oil produced in 1,322.7 days to define the oil saturation in place, and the latter in turn is related to the uniform pressure that can exist throughout the reservoir.

Thus,

\[
N_o = \frac{\varphi h r_w^2}{5.6146} \left( \frac{S_{ot} - S_o}{B_o} \right) \tag{53}
\]
Thus, by knowing oil saturation, the relative permeability for the oil is established (Fig. 6) that is related to pressure.

Therefore each term in Equation 31 can be established from the listings in Table 2 to yield the coefficient associated with the absolute time in the equation.

These are instantaneous effects. In the application to nonlinear flow for small pressure changes, it is expedient to take average values for the beginning and end of each increment.

This likewise applies to the $k_o/\mu_o$, in the rate relationship shown in Equation 46, as its instantaneous values from Table 2 and Fig. 6 can be averaged for the ensuing pressure change.

With respect to Fig. 8 and transient fluid flow, the initial calculations start at the well bore, $r_w$. Here the traverse is for a fixed radius using the $P(t_o)$ function of an earlier paper\(^7\) that applies for the constant rate-case of fluids producing from an infinite medium in a radial system.

At the choice of the author this continued for a pressure lowering to $\xi = 0.80$, when the effects of an enclosed reservoir came into existence.

A time of 31.8 days and $\xi = 0.80$ (Fig. 8) is the basis for establishing the drainage radius, $r_d$. This follows from the drainage formula\(^7\) with the coefficient for $t_o$ applying for the first pressure lowering from $\xi = 1.00$ to 0.975, to yield a drainage radius of 23,677.9 cm, or 776.8 ft. This is the enclosure for the illustrated problem.

In encountering the enclosure, both for its pressure lowering at this boundary with time and its areal sweep to the well bore, the mathematics used are the transcendental functions for a limited reservoir with the well producing at a constant rate.\(^7\)\(^9\)\(^10\)

Next is the areal sweep for the infinite case represented by Equation 46.

The earlier treatments for the $E_i$ functions are straightforward,\(^7\) but in the current problem we see a preliminary check on the work. In approaching the well bore for its fixed pressure $\xi = 0.80$, the calculated $r_w = 6.873$ cm, or 2.71-in. radius. The reported value is 2.75-in. radius, Table 3.

This likewise applies for the areal sweep for the time of 36.5 min. This curve is developed by the transformation of the curve for 31.8 days (Fig. 8). It was stated earlier\(^7\) that for the infinite case one curve can be determined from the other for fixed $\xi$'s by the relation that the radii squared are proportional to the times. As before, the radius realized in approaching the well for $\xi = 0.90$, is 2.71 in.

Then the gas produced at the well bore—for a constant rate of oil production—is related not only to the lowered pressures established in Fig. 8, but the physical data that define the gas/oil ratio at the well.

This gas/oil ratio is expressed as

$$GOR = \frac{k_o \mu_o \Phi_o}{k_0 \mu_o B_g} + R_1 \tag{47}$$
66,136.4 = \frac{(0.195)(22.3)(776.83298)^2}{5.6146} \frac{S_{wi} - S_o}{B_{wi} - B_o} (54)

where

\frac{S_{wi} - S_o}{B_{wi} - B_o} = 0.045042

Referring to Tables 2 and 4, \( \xi = 0.54476 \), or \( p = 236.4 \) psia that would prevail as a uniform pressure if the field were shut in at 1,322.7 days.

This is the basis for the material-balance equation following the concepts of Schlichtius, and it is expressed as

\[ N(B_i - B_o) = N_o \left[ B_i + (R_p - R_o)B_o \right] \] (55)

The oil in place \( N \) can be computed from the data given in Tables 3 and 4, to be 1,064,023 bbl of oil corrected to standard conditions.

The interest here is to find \( R_p \), the cumulative gas/oil ratio produced in 1,322.7 days.

For the computed average pressure that would apply in the Schlichtius formula, the oil produced in this time \( N_p \), and the information listed in Table 4 for the physical factors, the cumulative gas/oil ratio calculated is 545,50987 scf/bbl.

This multiplied by 66,136.4 bbl of oil produced, gives 36,078,068 cu ft of gas.

The reference to Fig. 7 that is independent of the material-balance equation, but established for two-phase fluid flow and the changing pressures in the well, gives 35,216,888 cu ft of gas produced over this interval, or an error of 2.44% in the calculations for the gas produced.

What was shown. What has now been shown for two-phase fluid flow can apply to interference between wells in a reservoir and to include the configuration of a field. This is the image problem discussed in the previous paper.\(^7\)

What has also been mentioned is that the variations in net sand thicknesses and permeabilities that occur within a reservoir can be accounted for in the mathematics.

In both these publications one dealing with gases,\(^7\) and this presentation for two-phase fluid flow, a pattern is evidenced that indicates its adaptability to other problems in reservoir engineering through explicit formulas that apply for nonlinear flow and obey the boundary conditions.

References

3. John L. Kennedy, "Where's the way reserves for the big new Hilight Field were estimated," O&G, May 18, 1970.