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# GAS IN GEOPRESSURE ZONES
Proceedings of a Working Group
June 21-24, 1979

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*editor*

May 1980
WP-80-93



INTERNATIONAL INSTITUTE FOR APPLIED SYSTEMS ANALYSIS
A-2361 Laxenburg, Austria

## PREFACE

During the second IIASA Conference on Energy Resources, jointly organized with UNITAR, on "The Future Supply of Nature Made Petroleum and Gas" (1976), there was strong interest and lively discussion about unconventional gas resources, especially gas in geopressure zones.

The Resources Group keeps a close watch on all developments in world conventional and unconventional oil and gas resources. It seemed appropriate to organize a small workshop in 1979 to assess the progress being made on the subject of gas in geopressure zones. It was decided to restrict participation, at this stage, to the two National Member Organizations really engaged in research on this topic, namely the U.S. and the U.S.S.R.

The meeting was held at Laxenburg on June 21 to 23, the following people participated:

Dr. A.I. Aliev,
All-Union Research Institute of Preparation,
Transportation and Processing of Natural Gas,
Baku, U.S.S.R.

Dr. A.K. Arsky,
Institute of World Economy and International
Relations of the U.S.S.R. Academy of Sciences,
Moscow, U.S.S.R.

Dr. D. Bebout,
Bureau of Economic Geology, Texas, U.S.A.

Professor M. Dorfman
The University of Texas, Austin, Texas, U.S.A.

Professor M. Grenon
International Institute for Applied Systems
Analysis, Laxenburg, Austria.

Dr. R. Loucks,
Bureau of Economic Geology, Texas, U.S.A.

Dr. V.D. Malevansky,
All-Union Research Institute of Natural Gas
of the U.S.S.R. Gas Industry Ministry,
Moscow, U.S.S.R.

Mr. J.M. Merzeau,
International Institute for Applied Systems
Analysis, Laxenburg, Austria.

Mr. G.G. Pighnasty
Committee for Systems Analysis at the
Praesidium of the U.S.S.R. Academy of Sciences,
Moscow, U.S.S.R.

Dr. V.I. Yermakov,
All-Union Research Institute of Natural Gas
of the U.S.S.R. Gas Industry Ministry,
Moscow, U.S.S.R.

Dr. D. Zinn,
The University of Texas, Austin, U.S.A.

Progress was reviewed, and the two delegations presented up to date information. This was followed by very active discussions. Most of the material presented is included in this Working Paper. There is also a summary of the discussions. Translations of the two main papers presented by the U.S.S.R. participants are given for information.

This Working Paper should be of interest, particularly in view of the fact that one outcome of the meeting was a common desire to devote the next IIASA Resources Conference to Natural Gas Resources in general, including a special session on gas in geopressure zones. This Working Paper should serve as a background paper for the 1980 Conference.

Michel Grenon

# AN OVERVIEW OF U.S. RESEARCH ON GEOPRESSURED GEOTHERMAL ZONES.

Dr. M. Dorfman
University of Texas at Austin
U.S.A.

One of the most significant geological sources of energy is the methane and the geothermal fluid contained in the geopressure zones of the United States Gulf Coast Basin. Investigations into the nature and dimensions of geopressure geothermal aquifers in the U.S. Gulf Coast have been proceeding since 1974 funded by Energy, Research and Development Administration (ERDA and its predecessor agency) and various industrial groups in Texas and Louisiana. The studies have centered on obtaining a thorough background of information concerning the extent of the potential resource, its physical parameters, fluid characteristics, potential for utilization as a source of electric power generation and other process heat applications, the technological procedures associated with well design and drilling, reservoir engineering studies, methane extraction techniques, and the institutional, legal and environmental implications of geothermal development. Research has been centered primarily at the University of Texas, Center of Energy Studies, and at Louisiana State University.

## GEOLOGICAL BACKGROUND

The Northern shoreline of the Gulf of Mexico extends more than 1,000 miles, from the Rio Grande River to the Florida "Panhandle". Underlying a large portion of this shoreline area, both onshore and offshore, in a strip 200 to 300 miles wide are clastic sedimentary deposits of great thickness. Figure 1 shows the area described, which lies between the landward boundary of the Miocene deposits and the edge of the outer continental shelf. Sediments within this young basin exhibit a maximum thickness of some 50,000 feet at major depot-centers located slightly offshore from Texas and Louisiana and subparallel to the present coastline.

The upper 25,000 feet of deposits in this basin are composed primarily of alternating series of rock layers which may be broadly classified as either sandstones or shales. The lower section of sediments consists almost entirely of shales. These sediments were deposited by prograde delta systems ranging in age from Eocene to Recent, with some subsequent rearrangements of sands due to the effect of relatively high-energy wave action at the juncture of terrestrial and marine environments. Rapid sediment loading from deltas throughout coastal Texas and Louisiana resulted in "leap-frogging" sediment distribution from a generally North to South direction. As younger systems deposited their sediment loads over the older units, great quantities of sand sank into the muds of the older delta systems. Sediments thus deposited became extremely thick on the South, or basinward, side. Continued downwarping due to sediment load resulted in "growth faults", or normal faults subparallel to the coastline due to differential compaction of sands and muds.

The penetration of sands into underlying pro-delta muds resulted in the isolation of large sand members from continuous permeability channels to the overlying strata. Above the intervals thus isolated, pressures throughout the basin approximate 0.465 psi/ft. This is considered normal hydrostatic pressure based on the fluid pressures exerted by a column of saline water. However, beneath the normally pressured zones the isolated units of sands and muds contain pressures far greater than normal. These abnormally pressured zones are now commonly referred to as geopressured zones. The generation of geopressure is primarily the result of compaction phenomena. Newly deposited sediments have high porosities and are saturated with water. As they are overlain by younger sediments and buried deeper, the pressure of overburden seeks to reduce the thickness and porosities of these deeper sediments. As both the rock and water have very low compressibilities, the only way the rock volume can be appreciably reduced is by expelling water, with a consequent decrease in porosity. The rate of expulsion of water is controlled by the permeability of the overlying rocks. If none of the water can escape, then the weight of the overburden causes the fluids contained in the lower sediments to bear a portion of the overburden load. The result is a sudden and dramatic increase in sediment and fluid pressure. Pressure gradients in the geopressured regions will flow naturally into wellbores and to the surface, and the hydraulic energy may be converted to useful purposes such as the generation of electricity. The geopressure interface in the Gulf Coast Basin occurs at depths of 5,000 feet to 15,000 feet, depending upon the age and distribution of sediments. All sediments below the general geopressure interface may be expected to contain increasing abnormal pressure with depth.

Temperature is also an important parameter if the heat content of the water produced is to be utilized as an energy source. It is apparent from studies of well logs run in boreholes in the Gulf Coast that temperature gradients of approximately 1.5°F/100 ft. of depth are found in hydropressured sediments of the Gulf Coast Basin; gradients in excess of

$3^{o}F/100$ ft. of depth are found in hydropressured zones. Temperatures at depths of 10,000 feet often range from $225^{o}F$ to $300^{o}F$, and at depths of 15,000 feet it is not uncommon to encounter temperatures in excess of $350^{o}F$. Within the basin, temperatures of over $500^{o}F$ have been encountered in boreholes at depths of approximately 20,000 feet. Although these temperatures do not compare favorably with those found in Western United States volcanic-associated geothermal systems, they may be of sufficient magnitude to be useful in a variety of energy applications.

Source beds for most, if not all, hydrocarbons within the Cenozoic portion of the Gulf Coast Basin are believed to be the shales within the geopressured zones. These beds have provided adjacent sands within the geopressured regions with certain concentrations of methane in solution, and great interest has been shown in the recovery of appreciable volumes of methane from geopressured water. Evidence of methane concentration on geopressured zones is based upon inflows of gas and water from blowouts, and from the large number of "kicks" encountered in drilling into geopressured sandstones. Additionally, gas measuring devices on mud logs usually record significant indications of gas saturation while drilling is in progress. Theoretical studies by Culbertson and McKetta (1952) indicate that between 30 and 50 standard cubic feet per barrel of water may be contained in solution in waters under high temperature and pressures encountered in geopressured zones. Buckley, Hocott, and Taggart (1958) made extensive investigations into the distribution of hydrocarbons dissolved in waters in the hydropressured regions of the Gulf Coast Basin. Hundreds of drill-stem tests on wells in the Frio formation indicated that the waters were essentially saturated at reservoir conditions. The dissolved gas was found to consist primarily of methane, with ethane and propane present only in minute quantities and minimal concentrations of heavier hydrocarbons were present. Methane concentrations of up to 14 standard cubic feet per barrel of water were found in these studies of normally pressured zones. It is also known that plentiful dry gas reservoirs exist in the Gulf Coast Basin in the uppermost portions of the geopressured zones, and that the gas is usually found to contain primarily methane with no evidence of hydrogen sulphide or other serious contaminants. Marsden and Kawai (1965) reported on "suiyosietennengosu", or natural gas dissolved in brine, found in over a dozen fields throughout Japan. At least two of these fields near Niigata and Tokyo produce gas commercially, and the gas is composed of over 90% methane, with the remaining constituents being primarily carbon dioxide and nitrogen. Therefore, inferential evidence would indicate that waters in geopressured zones should be essentially saturated with methane (Dorfman and Kehle, 1974). Estimates of the size of the resource vary widely (see Table 1).

Table 1. Assumptions for various resource assessments

| | Dorfman | Gould | Hawkins | Hise | House | Jones | Myers | Papadopulos | Schnadelbach |
|---|---|---|---|---|---|---|---|---|---|
| Area (sq. mi.) | 100,000 | 60,000 | 42,000 | 100,000 | 30,600 | 154,000 | 29,000 | 55,970 | |
| Area productive (%) | | 22.5 | | | 5 | | 1-50 | | |
| Thickness (feet) | 10,000 | 10,000 | 8,000 | 10,000 | 15,000 | 13,120-19,680 | 15,000 | 9,482-13,715 | |
| Sandstone (%) | 15 | 7.5 | 5.4 | 10 | 56 | 50 | 10-60 | 12-49 | |
| Porosity (%) | 22 | 20 | 20 | 20 | 20 | 25 | 15-35 | 18-22 | |
| Dissolved natural gas (scf/bbl) | 35 | 30-40 | 20.3 | 30 | 19-44 | 18.8-164 | 1-30 | 28.2-46.3 | 107 |
| Water in place (x $10^{12}$ bbl) | 164 | 10 | .67 | 100 | 10.9 | 1,492 | .126-88.2 | 657 | 1,042 |
| Gas in place (Tcf) | 5,735 | >300 | 13.6 | 3,000 | 221.7 | 100,000 | .126-2,646 | 23,636 | 111,500 |
| Recovery (%) | 5 | 50 | | 5 | 2-100 | >1.1 | .1-70 | .12-3.3 | |
| Recoverable water (x $10^{12}$ bbl) | 8.2 | 5.0 | | 5.0 | | >17.1 | .000126-61.7 | .79-21.7 | |
| Recoverable gas content (scf/bbl) | 30 | 30 | | 25 | | 30 | | | |
| Recoverable gas (Tcf) | ?56 | 150 | | 125 | | >1.146 | .0001-1,000 | 768 | |

Following the presentation there was an animated discussion covering the following points.

1. Re-injection of produced water

It was pointed out that there are ample sands existing at depths of 2,000 m (some 500 m thick) and at normal pressures, to re-inject for 20 years at high rates. Pressures at the surface will be $\pm$ 23 atm. The Soviet scientists indicated that disposal presented greater difficulties in many cases than had been experienced in the U.S. Gulf Coast. It was pointed out that water disposal in the Gulf Coast is a large, continuing business, since much water is re-injected after production from oil and gas reservoirs. In the large East Texas field some 460,000 bbl are re-injected per day.

2. The lifetime of large flow rates

Dr. Malevansky questioned whether aquifers could in fact produce at rates of 40,000 bbl/day for 20 years. Professor Dorfman indicated that only short-term tests had been run to date, and that long-term well testing (2 years or more) would be necessary to determine the answer to this question. Reservoir models (mathematical) had been devised to help resolve this question. Reservoir drives include:

a. compaction of sediments;
b. influx of $H_2O$ from shales;
c. expansion of $H_2O$;
d. solution gas.

Three factors may cause reductions in reservoir productivity:

1. limited reservoir size;
2. increase in gas saturation;
3. well-bore damage due to pressure draw-down at well bore.

The first test well is located deep in the basin, to avoid structural traps normally associated with oil and gas which often include faults or other features which limit reservoir size.

3. Amount of gas

Dr. Arsky questioned whether estimates of gas were based entirely on gas in solution, since the existence of additional free gas in aquifers has not yet been proven. Well logs and production tests should help resolve this matter. Additional free gas in aquifers could increase the amount of gas available by a factor of 3 to 5, but it would also decrease the production of water. In this event the geopressured aquifers may be of interest primarily for the production of gas and wells may no longer require a 20 year life in order to produce large quantities of methane.

4. Well location

Dr. Malevansky discussed problems associated with "blowouts" of wells in geopressured zones and Professor Dorfman described methods used to control these problems in the U.S. These include extensive use of well logs to estimate the top of geopressure changes,drilling fluids to prevent shale movement and casing design.

5. Economics

Dr. Arsky asked if an economic analysis had been made on the production of gas from geopressured aquifers. Professor Dorfman indicated that present estimates of the cost of gas vary from $4 to $4.50 Mcf. This is somewhat higher than gas from "tight gas sands" produced by massive hydraulic fracturing, but lower than LNG from Algeria and synthetic gas from coal and other sources.

GEOTHERMAL GEOPRESSURED RESOURCES
IN TEXAS AND LOUISIANA

D. Bebout
Bureau of Economic Geology
State of Texas
U.S.A.

Dr. Bebout presented a general review of the geothermal geopressured resources in Texas and Louisiana. For more than two and a half years the Bureau of Economic Geology and the Department of Petroleum Engineering, University of Texas at Austin, have been conducting a study to delineate areas favorable for the production of geopressured geothermal energy.

Dr. Bebout covered step by step the process of arriving at the selection of a site for the geopressured test well near Houston, Texas. The process proceeded from the definition of the reservoir size, fluid temperature, porosity and permeability of an "ideal" model.

A potential prospective area (fairway) must meet the following minimum requirements:

| | | |
|---|---|---|
| Area | : | 50 $mi^2$ |
| Sand thickness | : | 300 ft |
| Bottom hole temp | : | $300^oF$ |
| Permeability | : | 20 millidarcys (md) |

Adequate porosity (about 20%) was also an important consideration in selecting the prospective geothermal area. However, permeability is the most critical factor affecting fluid production rates and one of the major limiting factors is finding sufficient permeability with fluid temperatures greater than $300^o$. This investigation was divided into two major phases:

1. The study of the regional distribution of reservoir sandstones in geopressured Frio, Vicksburg and Wilcox Formations and identification of fairways.

2. A detailed study of these fairways in order to locate favorable areas in which to drill a test well.

Both parts have been completed for the Frio Formation and five geothermal fairways have been identified along the Frio trend in Texas: Hidalgo, Armstrong, Corpus Christi, Matagorda and Brazoria (Figure 2).

Massive sandstones are usually found between 6000 and 9000 feet. Dr. Bebout emphasized that the most promising reservoirs are generally deeper than most oil and gas reservoirs in the Gulf Coast. Dr. Bebout then described the main physical characteristics of the Brazoria Fairway, which was found to meet the specifications believed necessary for a succesful test of the resource.

The Brazoria Fairway is located in South West Galveston and Southern Brazorian counties. It is 20 miles long and 10 miles wide:

> An extensive progradation occurred during deposition of the lower part of the formation and large quantities of sand were transported far gulfward of the normal trend of main sand deposition. Thick deltaic sands accumulated in a large salt-withdrawal basin bounded on the updip side by growth faults which developed simultaneously with deposition. Fluid temperatures within this accumulation of several hundred feet of sandstone are higher than 300$^{o}$F. After deposition of this lower progradational part of the section, a transgression of the shoreline caused the main sand depocenter to shift updip where progradation resumed. However, the upper main sand trend of the Frio never again reached gulfward to the position of the lower depocenter. The top of geopressure occurs just beneath these updip massive sandstones where the fluid temperature is approximately 200$^{o}$F. The reservoir sandstones of the Brazoria Fairway are deltaic in origin and accumulated on the downdip side of growth initiated by salt movements.

Their thickness varies from more than 1200 feet, to the Southeast in the Danburg Dome area to less than 200 feet, to the Northeast at Chocolate Bayou:

> Permeabilities within these reservoirs are greater than 20 md: this high permeability is related to secondary leached porosity that developed in the moderate to deep surface. Consequently the Austin Bayou geothermal prospect has been identified in this Fairway (Fig 3).

> Detailed geological, geophysical and engineering studies conducted in the Austin Bayou Prospect have delineated a geothermal test well site. These studies indicate that the top of the sand section will occur at a depth of 13500 feet, and the base at 16500 feet. A total of 800 to 900 feet of sandstone should occur in this section of 3000 feet (at least 30% of the sand will have core permeabilities of 20 to 60 md). The temperature at the top of the sand section will be 300°F. The entire prospect extends over an area of 60 square miles. However, information about the depositional environments in which these sandstones were deposited indicates that each individual sandstone should not be expected to be continuous for more than 2 miles in a strike direction. In the Austin Bayou Prospect, formation water with salinity between 60000 and 80000 ppm and a temperature of 300°F should contain 40 to 45 cu. ft. of methane in solution. Water produced (about 5% of the fluid in place) at a rate of 20000 to 40000 BWPD from a well will be disposed of by injection into younger sandstone reservoirs.

In his letter of 17 July, 1979, Dr. Dorfman gave more information on this test-well:

> We have just completed the first geopressured well in Texas, and it appears to be as planned, based on early tests. The well appears capable of producing over 30,000 BWPD at a temperature of 150°C, with a dissolved gas ratio of 20-25 Scf/bbl. This is a bit less than predicted, but long term testing will determine whether or not this initial estimate is accurate.

In closing his presentation, Dr. Bebout said that the reservoir's performance was not yet known. The reservoir's driving force is not completely understood--for example, the evaluation of porosity and permeability with decreased pressure has only been studied as a laboratory test. Further information on Dr. Bebout's presentation is available in the Report of Investigations No. 91 which was published by the Bureau of Economic Geology in 1978 and is entitled "Frio Sandstone Reservoirs".

The presentation was followed by several questions which are summarized as follows:

-- Q. Is there any hydrodynamic connection between the geopressured prospective area?

A. No, the blocks are isolated because of the depositional environment.

-- Q. Approximately what is the volume of water in the prospect area?

A. The Brazoria test well prospective site has approximately 360 billion cubic feet of sandstone!

-- Q. What does the statement "5% of the fluids will be produced" mean precisely?

A. It is expected that approximately 5% of the in place fluids will be produced as a result of reservoir depletion from the original pressure to hydrostatic pressure.

-- Q. How can the stable rate of flow be ensured from high pressure zones that are isolated by growth faults.

A. Geopressured zones are not surface connected; therefore, large flow rates require large sandstone bodies.

-- Q. What is the extent of sandstone in the Gulf Coast Basin?

A. In Texas and Louisiana the formations are distributed over 800 miles along the coastline.

-- Q. Expected salinity?

A. 60,000 PPM

-- Q. How does one use thermal energy or fluids?

A. Several methods:

1. Thermal water flood of oil reservoirs
2. Sulphur extraction
3. Process heat application

-- Q. Is salinity an obstacle?

A. For some applications--yes, for others--no.

# THE NATURE OF ABNORMALLY HIGH FORMATION PRESSURES IN RECENT PRESSURE ZONES AND QUESTIONS CONCERNING THEIR FORECASTING

Dr. A.I. Aliev
All-Union Research Institute of
Preparation, Transportation and
Processing of Natural Gas, Baku,
U.S.S.R.

Dr. Aliev discussed high pressured zones in the Caspian Depression Area. A summary of his paper follows. For further details see the Appendix.

## SUMMARY OF PAPER

During the exploration of deposits of petroleum and gas at great depths, and in particular in geologically recent pressure zones possessing an active tectonic regime, major complications and accidents sometimes occur due to intense manifestations of abnormally high formation pressure (AHFP); frequently, very deep, and therefore expensive, wells are abandoned for technical reasons. This significantly decreases the effectiveness of drilling exploration and delays the discovery of productive petroleum deposits.

Geologically recent pressure zones with thick deposits of sediment are usually characterized by a compression regime of water-bearing systems where, in connection with the continuing processes of gravitational compaction of rock types, the gradients of porous pressure greatly exceed the hydrostatic gradient. These gradients of porous pressure are directed towards the side of detachment and discharge of sedimentary waters i.e. from the clay beds to the alluvial sand collectors, and from the zones of the greatest warping to the zones of discharge. This is illustrated by examination of data for the South Caspian Basin, where it is found that the gradients of formation pressures beyond the contours of the petroleum-containing strata increase in the direction of the regional submersion of strata. In the presence of gas deposits of great heights under conditons of regional development of AHFP in the entire water-head system, the irregular formation of pressures may obtain the maximum values at the expense of additional surplus pressures.

In this paper calculations of surplus pressures, depending on the height of gas, gas-condensate, and petroleum deposits, are presented; also, a number of questions are examined concerning the evaluation of the development of AHFP and the forecasting of AHFPs in new exploratory areas, with the objective of avoiding possible complications during drilling.

OPERATIONS RESEARCH AND SYSTEMS ANALYSIS
OF GEOTHERMAL GEOPRESSURED RESOURCES

Dr. D. Zinn,
The University of Texas
U.S.A.

Dr. Zinn gave detailed information on the operations research and systems analysis aspects of geothermal geopressured resources which are currently being carried out by the Center for Energy Studies at the University of Texas. This project is being financed by the U.S. Department of Energy (DOE)--for further details refer to Research Report No. 10 from the Center for Energy Studies entitled "Operations Research and Systems Analysis of Geothermal/ Geopressured Resources in Texas".

Preliminary scenarios have been prepared based on the construction of an electric plant, initially with a capacity of 25-30 MW. The construction is planned to take place at the Brazoria County well site in 1982. By 1998 all 50 development wells could be drilled here and by 2010 all prospective Frio fairways could be drilled and in production. The availability of deep drilling rigs (there are 50 deep drilling rigs in the Gulf area) would not appear to be a restriction. The time required to drill a production well is estimated to be 4 months. The key factor is the construction time of the power plant (about 3 years). In fact there would probably have to be more small wells than in the study.

In 1978 prices, electricity at the generation terminal could be sold at \$ 5/kilowatt hour (\$ 4.00/thousand cubic feet equivalent). A new program anticipates single-well production and small electrical plants with 5 MW capacity since it is difficult to find a reservoir large enough to support many production wells. Solution gas could be produced at \$ 4 to \$ 5/thousand cubic feet and one geopressured well of 40000 b/d would produce 2 $10^6$ cubic feet of gas per day.

Two possible methods for disposing of the gas pressure fluid were examined: shallow and deep reinjection. Shallow reinjection transfers the effluent from the power plant into saline aquifers at relatively shallow depths. Deep reinjection transfers the effluent back into the producing reservoir which varies in depth from 12000 to 20000 feet. Deep reinjection is much more expensive in terms of both initial cost and operation but it may help to maintain reservoir pressure, to increase the production of fluids and to minimize surface subsidence problems. Preliminary estimates are that deep reinjection may increase the lifetime of the reservoir by a factor of two and the total recovery by a factor of three.

The total investment required for the development of the geopressured resource is relatively high--similar to that of syngas--with the present cost of natural gas (approximately $ 2 per 1000 cubic feet) and its availability, so that the geopressured resource is not currently economically feasible. However, at present in the United States, negotiations are now underway with Mexican officials for gas at $ 3.50; gas from the North Slope, Alaska, will cost $ 6 and liquified natural gas from Algeria now costs $ 4.50. The higher price of unconventional sources of gas puts the geopressured energy into a more favorable perspective. A rough estimate of the cost of a geopressured production unit is given on page 15.

At present, the United States Department of Energy is supporting the Geopressure Program. This project will only be carried out as a research effort by the Department of Energy; economic utilization will have to be initiated by private industry. By the year 2000 it may be competitive with syngas, tar sands, etc., and could be economically attractive. There are other incentives for the use of geopressured gas in the United States. Within the next 2 years it will no longer be possible to use gas as boiler fuel for the generation of electricity. However, this does not include solution gas from the geopressured zone--thus, geopressured gas becomes more valuable. It should also be pointed out that the geopressured resource is located along the Texas and Louisiana Gulf Coasts where gathering pipelines are extensively distributed. Industrial development in this area consumes large quantities of process heat, thus providing a local need for hot water.

The Texas geopressured resources, as presented here, seem to be relatively small and rather limited. However, the geopressured fairways and prospects selected to date have been designed to test reservoirs with fluid temperatures higher than 150°C (300°F). Even within the zones of higher temperature these areas represent only the very best sites which should be tested first. Later, if early tests are favorable, areas which are now of lesser interest may be developed. In addition, in shallower reservoirs sandstone units are commonly thicker and have higher permeability. These factors increase the potential of lower-temperature geopressured reservoirs. Lower temperature, lower pressure and higher salinities decrease the potential. Regional assessment of these shallower zones is now being undertaken.

## GEOPRESSURE PRODUCTION UNITS

CHARACTERISTICS

| | | |
|---|---|---|
| - Production well : | number : | 1 |
| | depth : | 15000 ft |
| - Disposal well : | number : | 2 |
| | depth : | 1 shallow (≃5000-7000 ft) |
| | : | 1 deep (≃15000 ft) |
| - Electric Generating plant : | 5MW - Small well head unit | |
| - Fuel plant : | for water/gas separation | |

CAPITAL COST (1978 U.S. Dollars)

| | | |
|---|---|---|
| - Production well : | \$2 - \$3 $10^6$ | |
| Disposal well : | \$2.5 $10^6$ | |
| Electric plant : | \$3 $10^6$ | |
| Fuel plant : | \$2 - \$4 $10^6$ | for 40000 bbl/day |
| Total capital cost ≃ | \$11 $10^6$ | |

ENERGY PRODUCED

Gas production

with 40 scf/bbl Total gas production = 1600 Mcf/day

with $1.10^6$ Btu/Mcf Total BTU's produced = $1.6\ 10^9$ BTU/day

Electricity

Usable electric energy : $0.4\ 10^9$ BTU/day

Total energy produced : $2.0\ 10^9$ BTU/day

Bbl of oil equivalent per day : $\frac{2\ 10^9}{6\ 10^6}$ = 330 bbl/day

CAPITAL COST PER BBL OF OIL EQUIVALENT : \$33.33

This presentation was followed by a general discussion. Dr. Malevansky mentioned that geothermal energy is being produced in many areas within the U.S.S.R. and is being used for heating and agriculture. Some of the wells are artesian and some are pumped. Most of these are from geopressured reservoirs but some are as deep as 3000 meters. The heat is used locally.

In the United States on the other hand, development of this geothermal resource is limited to Oregon and Utah. The Utah resource is 300 meters deep and the water is of low salinity. Research at the University of Texas is now underway to develop low temperature, low salinity, geothermal resources in central Texas. A well is now being drilled to test this energy resource. The Department of Energy and General Crude Oil No. 2 Pleasant Bayou well, just completed in Brazoria County, Texas, will be the world's first test recovery of the geopressured geothermal resource.

The major problem in producing geothermal energy in the U.S.S.R. is the resulting mineralization. The investments needed to extract the salts contained are high and at present uneconomical. With technological progress in removal of salts and increasing need for these minerals in the future, such waters will become of increasing importance. The present value of the heat does not justify the high cost of injection into the subsurface.

In conclusion, it was suggested that the possibility that vast quantities of solution gas and hot water exist in geopressured zones justifies the geopressured geothermal research program now underway in the United States Gulf Coast. There is, however, a question as to the uniqueness of this young basin. Certainly the Niger Basin in Nigeria and the South Caspian Basin are very similar. The present-day economics are not favorable for extensive production. However, in future years, with rising prices of gas and decreasing gas production, this resource may have economic potential.

SANDSTONE CONSOLIDATION ANALYSIS TO DELINEATE AREAS OF HIGH QUALITY RESERVOIRS SUITABLE FOR THE PRODUCTION OF GEOPRESSURED GEOTHERMAL ENERGY ALONG THE TEXAS GULF COAST.

Dr. R. Loucks
Bureau of Economic Geology, Texas
U.S.A.

Dr. Loucks presented the main results of the analysis of the quality of lower sandstone reservoirs along the Texas Gulf Coast. The following is an abstract of the report by Loucks, Dodge and Galloway, which includes the main conclusions of the presentation.

Analysis of reservoir quality of lower Tertiary sandstones along the Texas Gulf Coast delineates areas most favorable for geopressured geothermal exploration. Reservoir quality is determined by whole core, acoustic log, and petrographic analyses.

Wilcox sandstones exhibit no regional reservoir quality trends. In the Lower and parts of the Middle and Upper Texas Gulf Coast the sandstones are relatively well consolidated, but in other parts of the Middle and Upper Texas Gulf Coast they show a reversal towards increased porosity at depth. Vicksburg sandstones have the poorest reservoir quality of sandstones of any formation feasible for geothermal energy. Frio sandstones show a systematic increase in reservoir quality from the Lower to Upper Texas Gulf Coast. This increase in reservoir quality correlates with changes in rock composition and cementation. Acoustic log analysis substantiates a progression of greater consolidation from the Upper to the Lower Texas Gulf Coast.

Wilcox sandstones are poorly to moderately sorted, fine-grained, quartzose lithic arkoses, becoming more quartz-rich from the Upper to the Lower Texas Gulf Coast. Most rock fragments are metamorphic and volcanic. Vicksburg sandstones are poorly sorted, fine-grained lithic arkoses. Rock fragments are mainly volcanic clasts with lesser carbonate and minor metamorphic clasts. Frio sandstones range from poorly sorted, fine-grained, feldspathic litharenites through lithic arkoses in the Lower Texas Gulf Coast to poorly sorted, fine-grained

quartzose lithic arkoses to subarkoses in the Upper Texas Gulf Coast. Volcanic rock fragments predominate in all areas; carbonate rock fragments are common in the Lower Texas Gulf Coast.

In spite of variations in composition, lower Tertiary sandstones exhibit a similar diagenetic sequence idealized as follows:

<u>Surface to Shallow Subsurface Diagenesis (0 to 1,200 m$^{\pm}$; 0 to 4,000 ft$^{\pm}$)</u> begins with formation of pedogenic clay coats, leaching of feldspar, and replacement of feldspar by calcite. Minor amounts of kaolinite, feldspar overgrowths, and Fe-rich carbonate are locally precipitated. Porosity is commonly reduced by compaction for the original 40 percent to less than 30 percent.

<u>Moderate subsurface diagenesis (1,200 to 3,400 m$^{\pm}$; 4,000 to 11,000 ft$^{\pm}$)</u> involves leaching of early carbonate cements and subsequent cementation by quartz overgrowths and later by carbonate cement. Cementation commonly reduces porosity to 10 percent or less, but this trend may be reversed by later leaching of feldspar grains, rock fragments, and carbonate cements. Resurrection of porosity to more than 30 percent can occur, but this may be reduced once more by later cementation by kaolinite, Fe-rich dolomite, and ankerite.

<u>Deep subsurface diagenesis (>3,400 m$^{\pm}$; >11,000 ft$^{\pm}$)</u> is a continuation of late Fe-rich carbonate cement precipitation.

Differences in intensity of diagenetic features that may correspond to changes in rock composition distinguish areas of high reservoir quality along the Texas Gulf Coast. Lower Texas Vicksburg and Frio reservoirs have extensive late carbonate cementation, whereas in the Upper Texas Gulf Coast carbonate cementation is minor. Wilcox reservoirs show no simple trend; quartz and lesser carbonate are the dominant porosity-reducing cements for which precipitation is governed by local chemical and physical conditions.

The Wilcox Group has good reservoir potential for geopressured geothermal energy in the Middle Texas Gulf Coast and possibly in adjacent areas, but other Wilcox sandstones are marginal. The Vicksburg Formation in the Lower Texas Gulf Coast is not promising. Reservoir quality in the Frio Formation increases from very poor in lowermost Texas, through marginal in the Middle Texas Gulf Coast to good through the Upper Texas Gulf Coast. The Frio Formation in the Upper Texas Gulf Coast has the best deep-reservoir quality of any unit along the Texas Gulf Coast.

Figures 4 and 5 are taken from Loucks, Dodge and Galloway and illustrate points made in the paper. Figure 4 shows the variations in the relative proportions of rock components (quartz, feldspar, volcanic and carbonate rock fragments) of the sandstone reservoir from the Upper to Lower Texas Gulf Coast. Figure 5 illustrates the fact that variations in the consolidation sequences of sandstone from different areas along the Texas Gulf Coast produce a wide range of reservoir quality. Knowledge of the sandstone consolidation history is an important tool in predicting both areal and vertical reservoir quality; continued studies of this type are essential for helping in the full development of the resource.

CONCERNING THE FORECASTING OF THE AVAILABILITY AND THE DEPTH OF ABNORMALLY HIGH PRESSURE STRATA DURING DRILLING

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Dr. Malevansky's paper gave the participants an opportunity to examine the drilling problems in geopressure zones. The paper is enclosed as an Appendix.

Analyses of water samples from wells show that salinity is about 60000 mg/1, i.e. twice as much as that of sea water. Moreover the water is too hot (≈120°F) for disposal in shallow water. Finally analyses of these geopressured waters show Boron concentrations ranging from 12 to 42 mg/1 which might prove very dangerous for plants and fishes. All these characteristics will probably prohibit water disposal at the surface (Gulf of Mexico, coastal bays, estuaries or lagoons).

The injection of huge quantities of this waste water into shallow and thick sandstone sections with high permeability seems to be the best method of minimizing adverse environmental impact. An injection well can store at least 10000 b/d, possibly 20000 b/d.

A second problem is the possible phenomenon of subsidence. As a result of the production of large volumes of geothermal fluid, declining reservoir pressure may cause compaction of sediment within and adjacent to the reservoir. The quantity of compaction depends on the pressure gradient, reservoir thickness and reservoir compressibility. These parameters can only be estimated and it is difficult to forecast the magnitude of environmental impacts of subsidence.

In the Houston area the local population is very sensitive to this problem because in this district there has already been an occurrence of up to two meters of subsidence as a result of the withdrawal of shallow water. In fact, Dr. Dorfman does not believe that subsidence would be of the same magnitude when fluid is withdrawn from 16000 feet. However, to monitor the effect of withdrawal, extensive equipment has been used. A mathematical model which was used for the testing well, forecasts a 6" maximum of subsidence over 10 years. It is worth recalling that when gas is produced 90% of the fluid in place is withdrawn, when oil is produced 30% to 50% of the fluid in place is withdrawn but in the case of geopressure, water represents only 5% of the fluid in place.

A further problem is caused by the fact that reinjection will not swell the formation but will pressurize it instead. There is therefore some risk of initiating movements along growth faults.

After discussion on Dr. Manevansky's paper, Dr. Bebout outlined the main environmental aspects related to the development of geopressure which are as follows:

--maintaining air and water quality
--liquid disposal
--possible subsidence

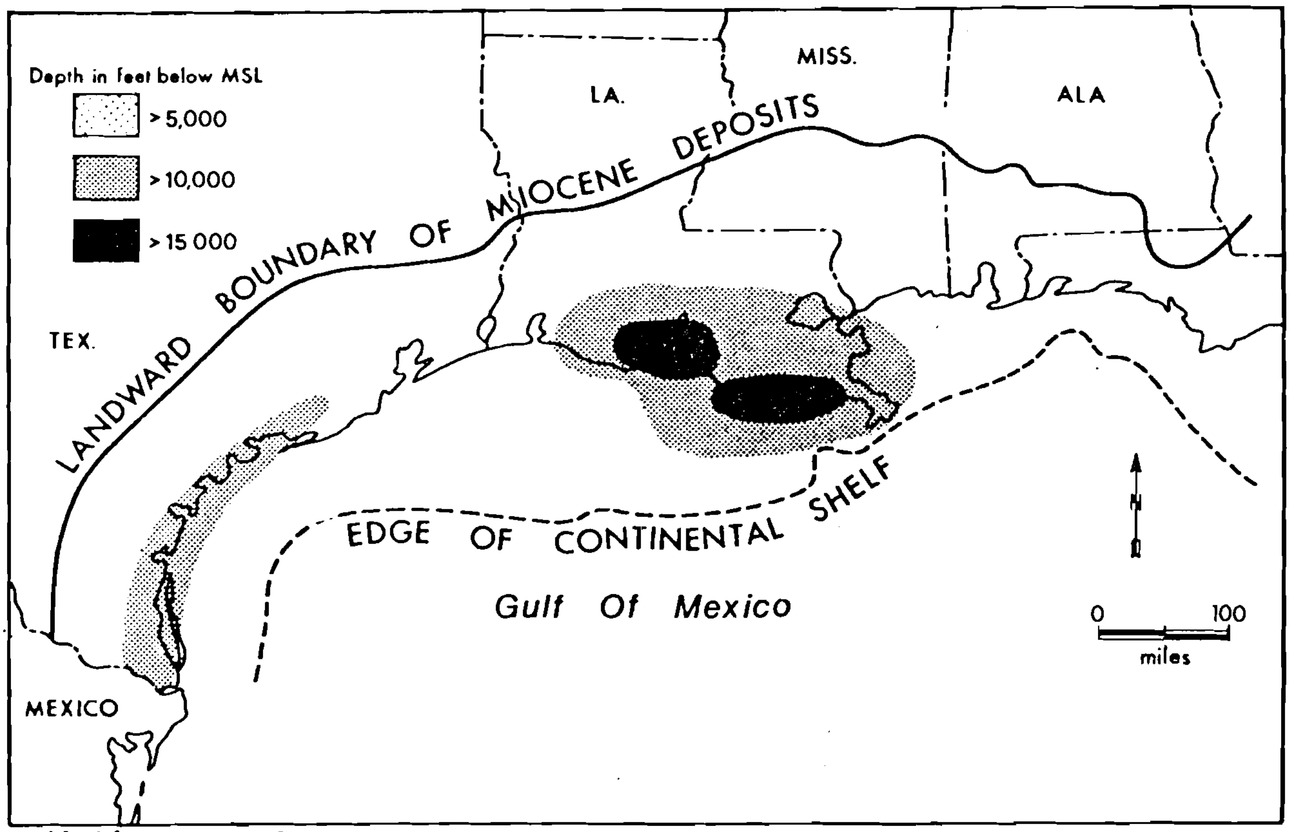



Figure 1. Depth of occurrence of the geopressured zones in Neogene deposits of the Northern Gulf of Mexico basin.

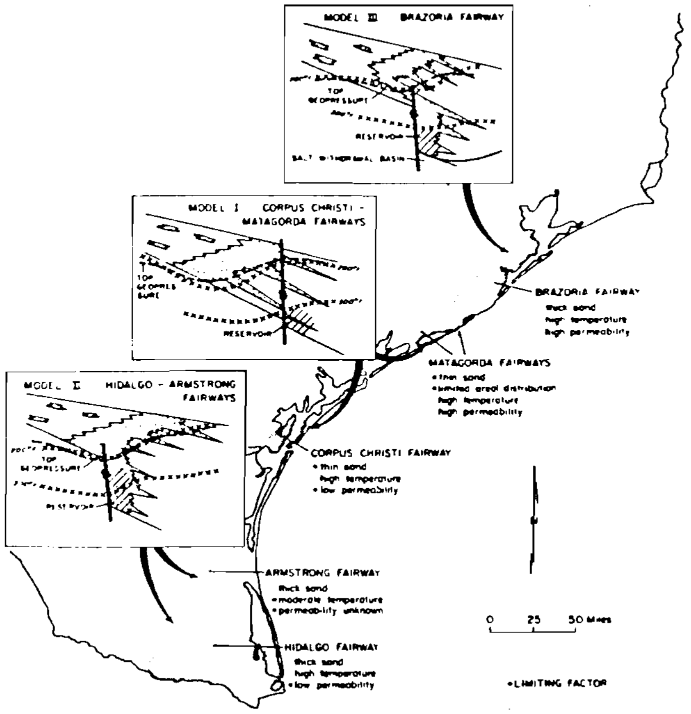



Figure 2. Frio geothermal fairways depositional models, and reservoir quality.

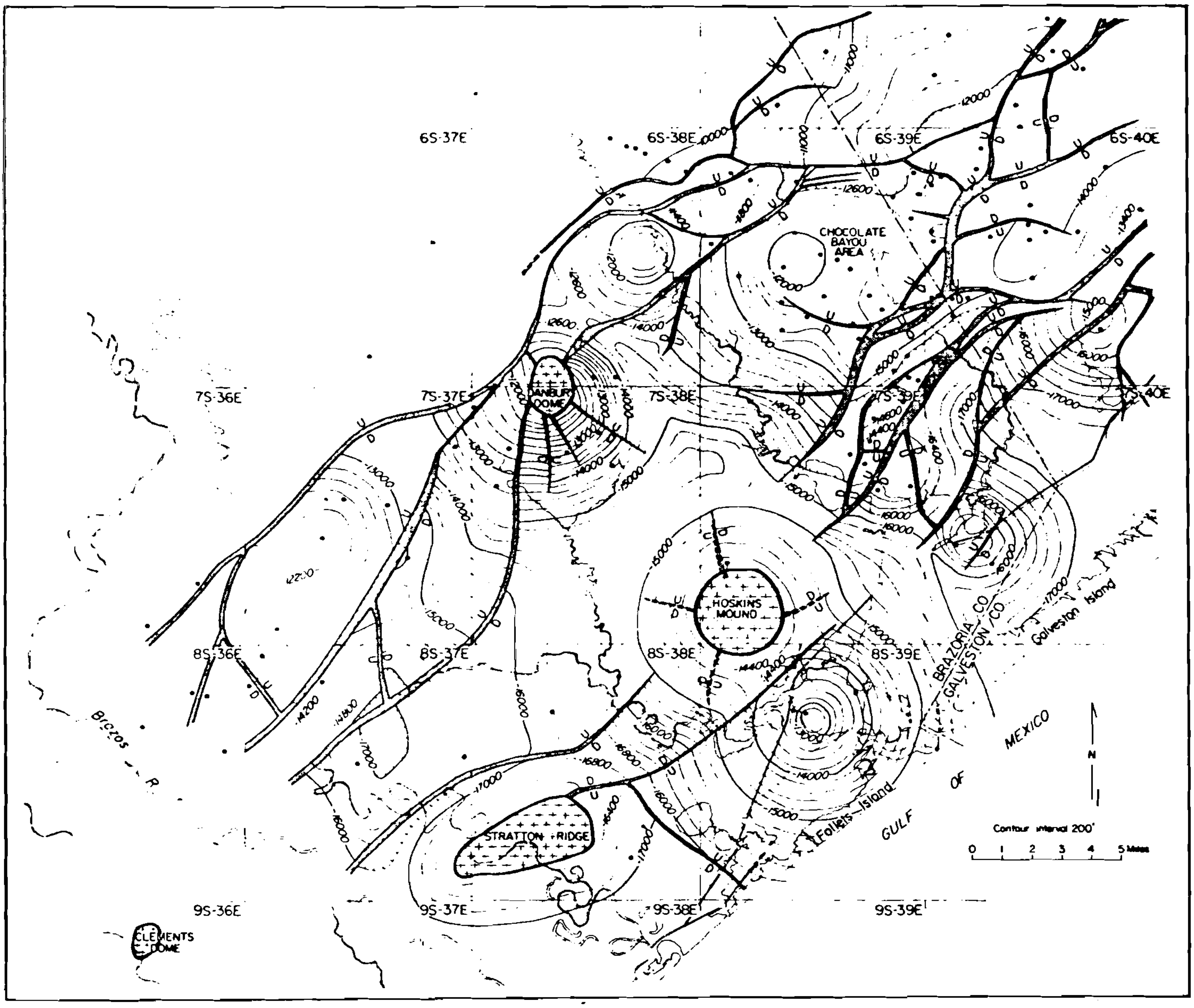



Figure 3. Structure map of the *Anomalia bilateralis* zone of the Frio Formation in Brazoria and Galveston Counties, Texas. A large salt-withdrawal basin is indicated by the structurally low area in the center of the map.

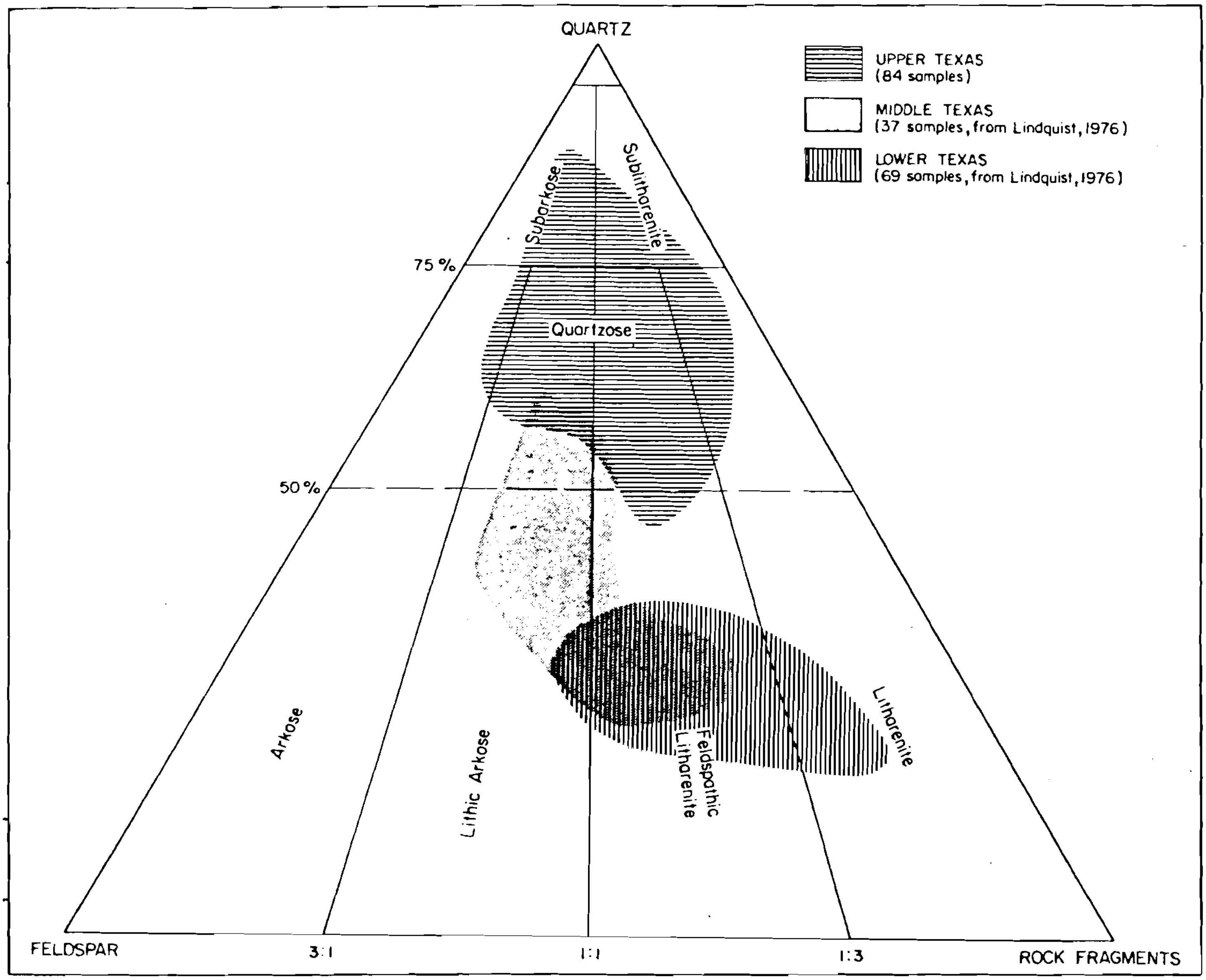



Figure 4. Sandstone composition of the Frio Formation along the Texas Gulf Coast. Sandstone classification after Folk, 1968.

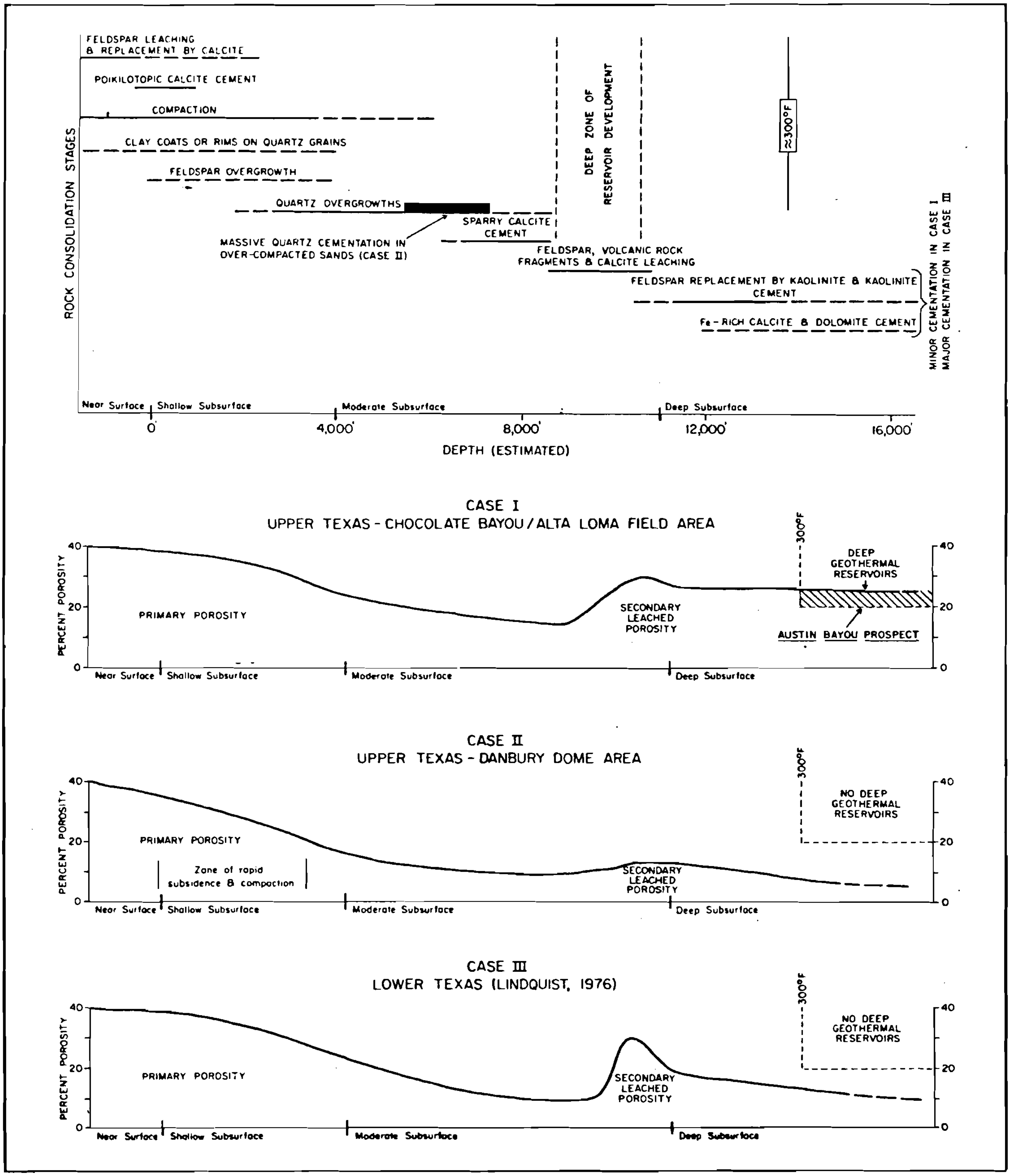



Figure 5. Rock consolidation stages with increasing depth and case histories of consolidation in the Chocolate Bayou/Alta Loma field areas, and Lower Texas area.

APPENDIX

# THE NATURE OF ABNORMALLY HIGH FORMATION PRESSURES IN RECENT PRESSURE ZONES AND QUESTIONS CONCERNING THEIR FORECASTING

Aliev, A.I.

SUMMARY

During the exploration of deposits of petroleum and gas at great depths, and in particular in geologically recent pressure zones possessing an active tectonic regime, major complications and accidents sometimes occur due to intense manifestations of abnormally high formation pressure (AHFP); frequently, very deep, and therefore expensive, wells are abandoned for technical reasons. This significantly decreases the effectiveness of drilling exploration and delays the discovery of productive petroleum deposits.

Geologically recent pressure zones with thick deposits of sediment are usually characterized by a compression regime of water-bearing systems where, in connection with the continuing processes of gravitational compaction of rock types, the gradients of porous pressure greatly exceed the hydrostatic gradient. These gradients of porous pressure are directed towards the side of detachment and discharge of sedimentary waters i.e. from the clay beds to the alluvial sand collectors, and from the zones of the greatest warping to the zones of discharge. This is illustrated by examination of data for the South Caspian Basin, where it is found that the gradients of formation pressures beyond the contours of the petroleum-containing strata increase in the direction of the regional submersion of strata. In the presence of gas deposits of great heights under conditions of regional development of AHFP in the entire water-head system, the irregular formation of pressures may obtain the maximum values at the expense of additional surplus pressures.

In this paper calculations of surplus pressures, depending on the height of gas, gas-condensate, and petroleum deposits, are presented; also, a number of questions are examined concerning the evaluation of the development of AHFP and the forecasting of AHFPs in new exploratory areas, with the objective of avoiding possible complications during drilling.

## INTRODUCTION

The study of abnormally high formation pressures (AHFPs), the laws governing their development both by areas and at the regional level, and the basic reasons for their appearance has an important practical significance. The object is to avert possible complications during the process of deep drilling, particularly at new exploratory sites. Frequently, during the exploration of deposits of oil and gas at great depths, major complications and accidents caused by intense manifestations of AHFP occur, causing expensive and excessively deep wells to be abandoned before completion for technical reasions. This significantly decreases the effectiveness of drilling exploration, delays the discovery of productive petroleum deposits, and, in a number of cases, causes exploratory drilling at prospective sites to cease. In order to increase the effectiveness of exploratory work, the forecasting and control of AHFP during the process of drilling is a most important measure. In addition, it is necessary to evaluate the nature of the AHFP correctly. However, in the majority of studies that have been published in the geological literature, any excess of the initial formation pressure over the hydrostatic pressure has been assumed to be abnormal; i.e. what is normally examined is not what leads to increased formation pressure (IFP) but the measurement of the pressure within the confines of the deposits. At the same time it is known that, depending on the height and the compactness of the hydrocarbon fluids in question (oil, gas, gas-condensate mixture) under formation conditions, the surplus pressure may attain a significant value at the normal hydrostatic pressure beyond the contours of the oil-bearing areas.

## 1. SURPLUS PRESSURE

We have carried out calculations of surplus pressures for different heights and depths of petroleum, gas, and gas-condensate deposits, taking into account the compactness of the hydro-carbon fluids under formation conditions. These results are given in Tables 1, 2, and 3, and show that the gradients of formation pressures increase significantly at the expense of surplus pressure, depending on the heights of gas and gas-condensate deposits. In addition, the surplus pressure influences the gradient of formation pressure significantly at lesser depths (up to 3000 m). Thus, for example, because of the surplus pressure at a depth of 1000 m, with a gas (or gas-condensate) deposit of 1500-2000 m in height, the gradient of formation pressures may exceed even the geostatic gradient, even though such deposits do not exist in nature at lesser depths for this reason alone.

The results of calculations have shown that, as the depth increases, the significance of the surplus pressure decreases in gas and gas-condensate deposits, in combination with an increase in the gas/condensate ratio under formation conditions with increased pressure. In petroleum deposits the oil/gas ration decreases with depth due to a significant increase in the proportion of gas dissolved in the deposit; if other geological conditions remain constant, this leads to an increase of surplus pressure (see Tables 1, 2, and 3).

Figure 1 illustrates the changes of the gradients of formation pressure with depth, depending on the height of gas, condensate, and petroleum deposits, which shows to what degree the value of the surplus pressure is significant in the manifestation of AHFP, especially in gas-bearing regions. In addition, as the depth of deposits increases, the influence of surplus pressure on the gradients of formation pressure decreases. Figure 1 provides a basis for supposing that, beyond the contours of petroleum-bearing strata the high gradients of formation pressure are negative factors for the preservation of gas and gas-condensate deposits at lesser depths (up to 3000 m), since the sum of the gradients of surplus and formation pressures for the IFP should not exceed the geostatic gradient. Together with this, at greater depths, the influence of surplus pressure on the gradients of formation pressure decreases significantly; and in this respect, deep horizons are more favorable for the preservation of a high level of gas and gas-condensate deposits, even in zones where AHFP occurs.

## 2. INITIAL FORMATION PRESSURE

Analysis of a large amount of data concerning initial formation pressures for the western edge of the South-Caspian Basin, which represents a more recent region of warping in the system of the Alpine geosyncline, has shown that all of the exposed deposits of oil and gas in the region are characterized by a significant increase in the initial formation pressure over the hydrostatic pressure, not only within the confines of the deposits, but beyond the contours of oil- and gas-bearing areas. The IFP values exceed those of the hydrostatic pressures and consequently the gradients of formation pressure, independently of their type and the character of the deposits, increase, thus favoring the regional submersion of strata, as is generally stipulated by the condition that the entire water-head system be formed during the sedimentation cycle of the water exchange (see Figures 2 and 3). In all cases the gradients of the pressure heads of formation waters are directed from the more submerged parts of the basin towards the rims and the more elevated tectonic elements. Under conditions of a regional development of AHFP in the entire water-head system of the South Caspian Basin, as stipulated by the compression stage of the hydro-geological cycle when deposits of oil and gas are present at great heights, the abnormality of formation pressure may attain maximum values at the expense of additional surplus pressures. Thus, at a regional level, the evaluation of the gradients of formation pressure beyond the contours of oil- and gas-bearing areas is characterized by the dynamics of formation waters of separate stratigraphical intervals, and consequently knowledge of the formation and structure of the water-head system of oil- and gas-bearing regions is an important prerequisite for forecasting the occurrence and nature of AHFP at new exploratory sites.

## 3. EVALUATION OF AHFP

It is known that, during the evaluation of AHFP, IFP data from the sampled sand-section intervals are used which are significantly lower than the values of the porous pressure in clays. Under conditions of gravitational compactness of terrigenous rocks in geologically recent pressure zones, the pressure-head gradients of sedimentary waters are oriented towards the direction of their detachment and discharge, i.e., from clay strata to alluvial sand collectors and from the zones of greatest warping to the zones of discharge. Consequently, in sand strata which are adjacent to clay-section intervals with AHFP, the porous pressure will be still greater. This fact should be taken into account during the drilling process. In addition, during the uncovering of the clay-section intervals, in contrast to the sand strata, the gas occluded under great pressure in the closed pores of the clay, tends to increase its volume, and this finally leads to a protrusion of clay rock types towards the stem of the well. For these reasons, the overwhelming majority of the complications and accidents occurring during the process of the drilling of deep wells will generally be limited to the clay-section intervals.

During the drilling process it is frequently found that the "development of AHFP" and whole series of further complications occur during the gassing of the clay mud in the stem of the well; this takes place during the uncovering of gas-bearing alluvial sand strata, and the complications arise, regardless of their pressure or the volume of gas contained in the strata. In a number of cases, proceeding from the specific weight of the clay mud used, abnormality of the formation pressure of the uncovered section interval is falsely evaluated when calculating the gassing of the clay mud during the drilling process, because the physical properties of the gas have not been taken into account. In fact, even with a normal formation pressure and a small volume of the deposit uncovered, the gas easily penetrates into the stem of the well and, by gassing the clay mud, lowers its specific weight. In addition, during the increase of the specific weight and viscosity of the clay mud the conditions for its de-gassing become worse, and a large amount of gas accumulates in the stem of the well, both in the form of separate bubbles and in the form of "gas pillows". Finally this leads to a short-term open fountain, complicating the drilling process.

## 4. THE REGIONAL CHARACTER OF AHFP

During the evaluation of the development of AHFP in the uncovered part of the sedimentary section of the western rim of the South Caspian Basin, it was established that the gradients of formation pressures beyond the contours of the oil- and gas-bearing areas in the Upper Pliocene intervals do not exceed 1.20-1.25, and that they increase with stratigraphic depth, attaining values of 1.60-1.80 at the lower horizons of the productive thickness of the Mid Pliocene. In addition, the value of the gradients of the initial formation pressures depends on the rate of the gravitational compaction of rock types which, in turn, is controlled by the speed of discharge of sedimentary waters and, consequently, by the lithofacial conditions of the section. In the case of non-uniformity and a high percentage of clay in the section, the rate of discharge of sedimentary waters lags behind the rate of the submersion of the sediments, which leads to an increase in porous pressure, and for this reason in a number of cases the distribution of gradients of formation pressure has a fluctuating character in some stratigraphic intervals. From this it follows that, in order to forecast the AHFP, under otherwise equivalent geological conditions it is necessary to distinguish those lithologically heterogenous intervals of the section that have a regional character.

## 5. ZONES IN WHICH WATER EXCHANGE IS DIFFICULT

It is known that the development of AHFP during the drilling process is chiefly observed in geologically recent pressure zones during the uncovering of deep horizons. The research that we have conducted, as well as analysis of the available data from outside the U.S.S.R., indicates that the largest gradients of formation pressure during gravitational compaction of rocks are confined to zones where exchange is difficult, at depths below 2500-3000 m. In addition, zones where water exchange is difficult are, in each specific case, determined by the geological conditions of the region (e.g., the lithofaces of the section, the rates of submersion of the sediments, the discharge of sedimentary waters, etc.).

In the area of the South Caspian Basin the gradients of formation pressure for depths of up to 3000-3200 m vary within the limits 1.12-1.15 and lower, and increase sharply up to 1.80 (see Figure 2). Thus at depths lower than 3000-3200 m the initial formation pressure beyond the contours of the oil- and gas-bearing areas exceeds the hydrostatic pressure by 80%, and when gas deposits are present, this excess will be still greater. This should be taken into account during drilling.

Together with a correct evaluation of the actual geological conditions, the study of the laws governing the regional appearance of AHFP in large pressure zones has an important significance for the forecasting of AHFP in new exploration areas.

## 6. THE LOCAL APPEARANCE OF AHFP

As is the case with regional forecasts, it is also very difficult to forecast the local appearance of AHFP. Local abnormalities of formation pressures may be encountered at hydrodynamically confined traps (tectonic and lithologically confined deposits). The research that we have carried out has shown that hydrodynamically confined deposits are small in size, and that they are characterized by significant increases in the formation pressure over the hydrostatic pressure. During the extraction of such deposits, an intense drop of formation pressure is observed. (In a number of cases, this drop has been as great as 10-15 kg/cm$^2$ per month.)

The development of AHFP often occurs during the drilling processes connected witn hydrodynamically confined deposits; for this reason, due to the abnormality of formation pressures, the estimates of the size of the deposits that are often suggested by researchers are frequently not justified on the basis of subsequent exploratory work. Consider, for example, the gas-condensed deposits of the V. horizon of Duvanny (south-western Kobystan). For Well No.43 in this area, which entered into the exploratory stage with a daily yield of 1 million $m^3$ of gas, and 125 tons of condensate from a sampling interval of 2606-2588 m, the formation pressure was originally 430 $kg/cm^2$ and exceeded the hydrostatic pressure by 170 $kg/cm^3$ for the gradient of 1.65; in spite of the fact that this was the only well that drained the deposit during the year, the formation pressure in it decreased to 250 $kg/cm^2$ during the year, and the daily yield decreased to 14000 $m^3$ of gas and 5 tons of condensate. The reserves of gas of this deposit turned out to be only 1 billion $m^3$, in spite of the excessively high formation pressure. One may cite many similar examples from field work in Azerbaidjan.

## 7. FORMATION AND LOCATION OF OIL AND GAS DEPOSITS

The study of the distribution of gradients of initial formation pressures beyond the contours of oil- and gas-bearing areas at a regional level, makes it possible to solve a series of most important problems of petroleum geology. In particular, the gradients define the dynamics of formation waters, which have a substantial significance during the evaluation of the conditions for the formation and location of deposits of oil and gas.

It should be noted that the hydrodynamic regime of water pressure-head complexes is a determining condition for the migration and accumulation of hydrocarbons. From this we can assume that the organic material in the sedimentary complex that is continuously transformed into hydrocarbons is transported by formation waters in a dissolved and dispersed state from zones of high potential energy to zones of low potential. In this way, the hydrocarbons accumulate in traps, under conditions determined by the dynamics of the formation waters in the directions of decreasing pressure-head gradients, both by means of lateral migration (at a regional level) and by vertical migration of hydrocarbons along the fracture plane and cracks (in zones of discharge).

If we examine the conditions for the formation or accumulation of hydrocarbons, starting from the existing dynamics of the formation waters and extending this to the entire history of the geological development of the oil- and gas-bearing areas of a region, it is possible to distinguish the features of location or the reasons for the presence or absence of deposits of oil and gas in each particular case.

Based on the data for the western rim of the South Caspian Basin, it has been established that high pressure-head gradients of formation waters are not desirable conditions for the preservation of deposits of oil and gas in traps.

As early as the 1950s, the removal of the deposits from the Apsheronski Peninsula reserves was correctly explained by the presence of a high pressure-head of the formation waters. This explanation has been subsequently confirmed by studies of deposits in other regions.

Thus, we see that AHFP is not always a positive factor for the evaluation of the prospective yields of oil- and gas-bearing areas, and that, in a number of cases, it leads to destruction of the deposits of oil and gas. This is also confirmed by the fact that the largest oil deposits in Azerbaidjan are concentrated in zones of relatively low gradients (close to the hydrostatic gradients) in the pressure head of the formation system in the Apsheronski oil- and gas-bearing region.

## CONCLUSION

To summarize, the study of AHFP is important for all the following stages: during the classification of the dynamics of formation waters and the nature of water pressure-head systems that determine the conditions for the migration and accumulation of hydrocarbons; during the forecasting of the section intervals where AHFP may occur, with the objective of averting possible complications in the process of drilling; and, finally, during the evaluation of the thermodynamic regime at great depths in oil- and gas-bearing regions, in connection with the problem of searching for new deposits.

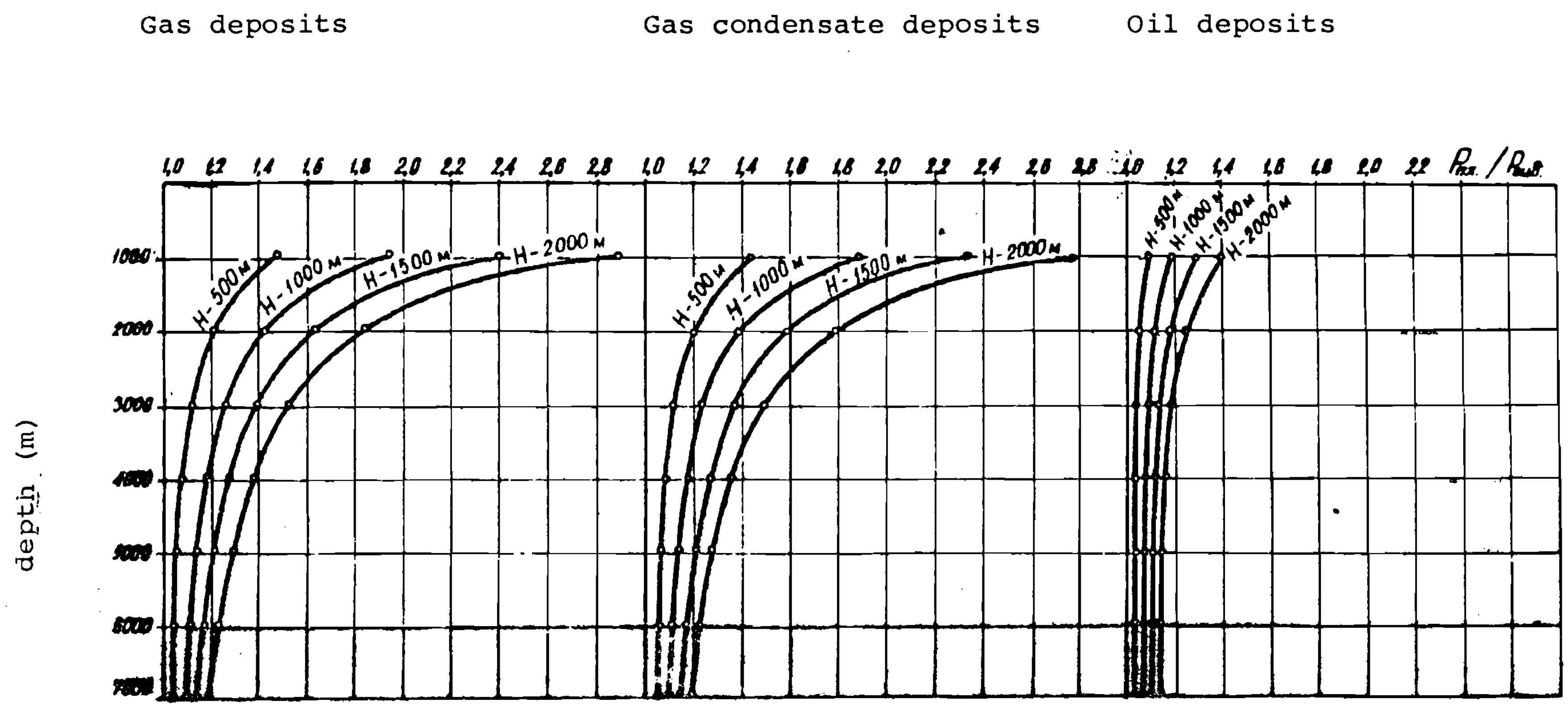
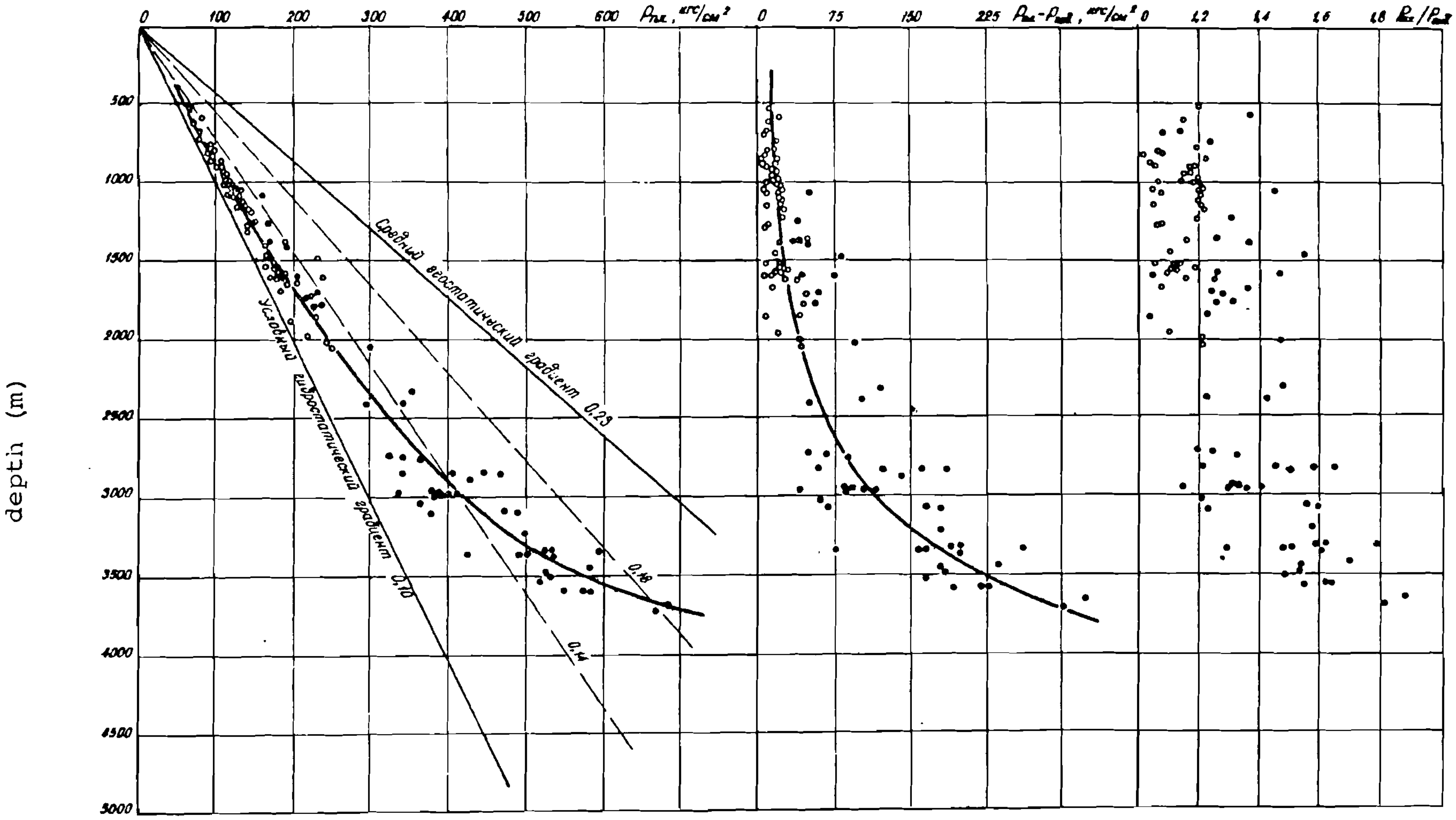



Figure 1. Calculated curves of the change of formation pressure gradients with depth, depending on deposit height.




Apsheronsk region

Nizhnekurinski Basin

Figure 2. The western rim of the South Caspian Basin. Changes in the initial formation pressures and values of P area/P hydro for IFP deposits with depth.

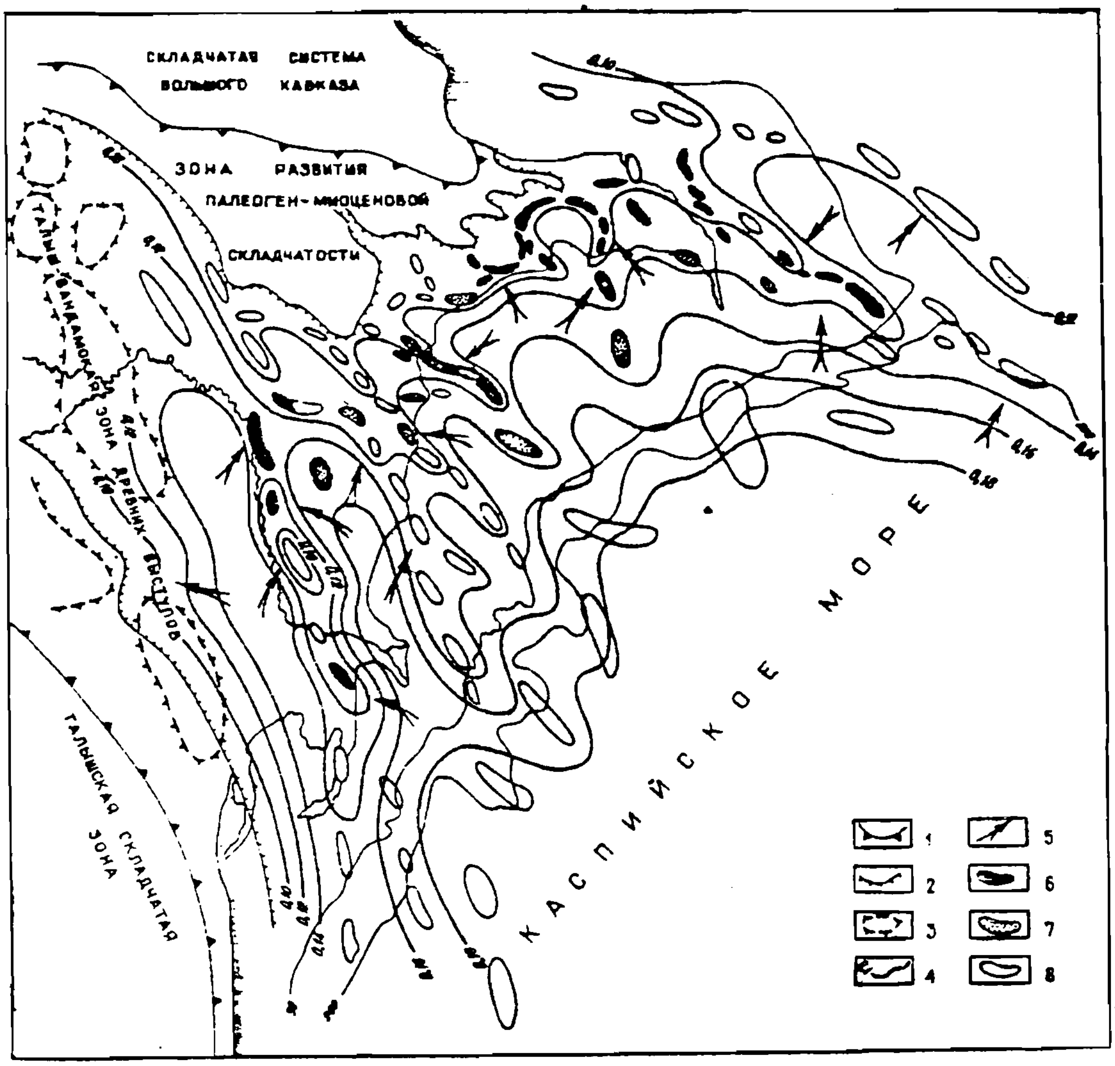



Figure 3. The western rim of the South Caspian Basin Schematic gradient map of the derived formation pressures of the productive thickness of the Middle Pliocene period.

Key:
1. The boundaries of large tectonic elements
2. The boundaries of the distribution of the sediments of the productive thickness of the Middle Pliocene period.
3. The local positive abnormality of strenth of gravity.
4. The lines of equal formation-pressure gradients.
5. The direction of movement of underground waters.
6. Oil deposits.
7. Gas-condensate deposits.
8. Development of the structure.

Table 1. Gas deposits

| DEPTH (M) | RELATIVE WEIGHT OF GAS UNDER FORMATION CONDITIONS | DEPOSIT HEIGHT (M) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 500 | | I000 | | I500 | | 2000 | |
| | | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] |
| I000 | 0,06I4 | 46,9 | I,47 | 93,9 | I,94 | I40,8 | 2,4I | I87,7 | 2,88 |
| 2000 | 0,I570 | 42,I | I,2I | 84,3 | I,42 | I26,4 | I,63 | I68,6 | I,84 |
| 3000 | 0,I960 | 40,2 | I,I3 | 80,4 | I,27 | I20,6 | I,40 | I60,8 | I,54 |
| 4000 | 0,2300 | 38,5 | I,I0 | 77,0 | I,I9 | II5,5 | I,20 | I54,0 | I,39 |
| 5000 | 0,2520 | 37,4 | I,07 | 74,8 | I,I5 | II2,2 | I,22 | I49,6 | I,30 |
| 6000 | 0,2660 | 36,7 | I,06 | 73,4 | I,I2 | II0,I | I,I8 | I46,8 | I,24 |
| 7000 | 0,2820 | 35,9 | I,05 | 7I,8 | I,I0 | I07,7 | I,I5 | I43,6 | I,20 |

[a] Surplus pressure
[b] Formation pressure

Table 2. Gas condensate deposits

| DEPTH (M) | RELATIVE WEIGHT OF GAS UNDER FORMATION | DEPOSIT HEIGHT (M) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 500 | | I000 | | I500 | | 2000 | |
| | | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] kg/cm$^2$ | $P_{form.p}$ [b] |
| I000 | 0,II3 | 44,3 | I,44 | 88,7 | I,89 | I33 | 2,33 | I77,4 | 2,77 |
| 2000 | 0,I95 | 40,2 | I,20 | 80,5 | I,40 | I20,7 | I,60 | I6I,0 | I,80 |
| 3000 | 0,242 | 37,9 | I,I3 | 75,8 | I,25 | II3,7 | I,38 | I5I,6 | I,50 |
| 4000 | 0,283 | 35,8 | I,09 | 7I,7 | I,I8 | I07,5 | I,27 | I43,4 | I,36 |
| 5000 | 0,298 | 35,I | I,07 | 70,2 | I,I4 | I05,3 | I,2I | I40,4 | I,28 |
| 6000 | 0,3I2 | 34,4 | I,06 | 68,8 | I,I8 | I03,2 | I,I7 | I37,6 | I,23 |
| 7000 | 0,332 | 33,4 | I,05 | 66,8 | I,I0 | I00,2 | I,I4 | I33,6 | I,I9 |

[a] Surplus pressure
[b] Formation pressure

Table 3. Oil deposits

| DEPTH (M) | RELATIVE WEIGHT OF GAS UNDER FORMATION CONDITIONS | DEPOSIT HEIGHT (M) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 500 | | I000 | | I500 | | 2000 | |
| | | $P_{sp}$ [a] $kg/cm^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] $kg/cm^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] $kg/cm^2$ | $P_{form.p}$ [b] | $P_{sp}$ [a] $kg/cm^2$ | $P_{form.p}$ [b] |
| I000 | 0,808 | 9,6 | I,096 | I9,2 | I,I92 | 28,8 | I,288 | 38,4 | I,384 |
| 2000 | 0,764 | II,8 | I,059 | 23,6 | I,II8 | 35,4 | I,I77 | 47,2 | I,236 |
| 3000 | 0,720 | I4,0 | I,046 | 28,0 | I,093 | 42,0 | I,I40 | 56,0 | I,I86 |
| 4000 | 0,657 | I7,2 | I,042 | 34,3 | I,085 | 5I,4 | I,I28 | 68,6 | I,I7I |
| 5000 | 0,638 | I8,I | I,036 | 36,2 | I,072 | 53,4 | I,I08 | 72,4 | I,I44 |
| 6000 | 0,6I8 | I9,I | I,03I | 38,2 | I,063 | 57,3 | I,095 | 76,4 | I,I27 |
| 7000 | 0,602 | I9,9 | I,028 | 39,8 | I,056 | 59,7 | I,085 | 79,6 | I,II3 |

[a] Surplus pressure
[b] Formation pressure

# CONCERNING THE FORECASTING OF THE AVAILABILITY AND THE DEPTH OF ABNORMALLY HIGH PRESSURE STRATA DURING DRILLING

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In geological structures in many parts of the world, and particularly in mobile neotectonic active zones on land and on continental shelves, fluids (such as water, oil and gas) are found which contain large stores of energy in the form of high pressures or temperatures that enable the fluids to permeate porous layers.

According to the terminology widely used in the U.S.S.R. [2], the formation (porous) pressure is graded according to its magnitude, as follows:

- Specific hydrostatic pressure--represented by the hydrostatic pressure of a hypothetical fresh-water column between the well head and the depth concerned, with an average gradient of 0.1 atm/m;
- normal formation pressure (NFP)--represented by the hydrostatic pressure of a column of mineral-containing water, with an average gradient of 0.105 atm/m;
- increased formation pressure (IFP), with a gradient of 0.106-1.29 atm/m;
- abnormally high formation pressure (AHFP), with a gradient of 1.3 atm/m or more;
- abnormally low formation pressure (ALFP) with a gradient of less than 0.1 atm/m.

The degree of abnormality of formation pressure is shown by how many times the measured formation (porous) pressure is larger or smaller than the specific hydrostatic pressure.

Usually the term gradient of formation pressure (average) characterizes the relationship of this pressure to the depth of the drill hole of the section under consideration, i.e., it is numerically equal to the gradient of the hydrostatic pressure of the drilling-mud column that balances the given formation pressure.

In contrast to the *average* gradient of the interval, the *local* formation pressure expresses the relationship between the increase of the formation pressure on any given segment along the drill hole to the length of this segment.

In the U.S.S.R., AHFP and IFP deposits have been encountered at depths of 400-500 m in the Kerchensk, Tamansk, and Apsheron Peninsulas, and at depths of 7000 m and more in the plicated Carpathians. These deposits are more frequently found, at depths of more than 2000 m, in terrigenous sediments covered with very thick clay strata (in areas such as the external zone of the Pre-Carpathian bend, the East Pre-Caucasian, the Viluysky syncline, etc.). In particular, highly pressurized, thermal, strongly mineralized waters with large flow rates are encountered in South-West Tadzhikistan at depths of 2000-2500 m.

There are also abnormal pressure deposits in salted or moderately salted terrigenous and carbonate sediments (in the Pripyatskaya, Dneprovsko-Donetakaya and Pre-Caspian depressions, in the Irkutsk amphitheatre, and in West Uzbekistan and West Turkmenistan). Many instances of ALFP have been found in salted carbonate and terrigenous sediments of South-West Yakutia and in some parts of the deposits of the Irkutsk amphitheatre.

There are a number of well-known but differing opinions concerning the nature of AHFP and the reasons for its appearance. The accumulation of various data, and the analysis of a great deal of complex geological and industrial information, referring to many different deposits [2], have led, in the U.S.S.R., to the following opinions: namely, that the AHFP arises mainly from localized processes involving the hindered vertical migration of fluids through fairly impervious overlying beds under the influence both of processes of neotectogenesis and of the excessively high formation pressures which reflect the neotectonic energy of the depth of the abyss.

AHFP and IFP deposits are regularly distributed in the depths of deposits within very thick strata and underneath these thick layers.

High-pressure fluids that are contained in massive deposits penetrate gradually from the bottom into the overlying layers, forming intrusion haloes, in which IFP or AHFP is observed.

The permeable layers and lenses within the intrusion haloes are also saturated with fluids, generating small satellite IFP and AHFP accumulations.

The gradient of formation pressure within large reservoirs of great height which are filled with oil or gas increases from the bottom to the top, reaching a maximum at the top of the bed on the arch of the structure.

In addition, even under the pressure of contour waters which are close to the hydrostatic pressure, the maximum pressure at the arch of massive deposits may be highly abnormal. Thus, for example, in the gas-condensate deposit of Kara-Dag (U.S.S.R.), which is 1850 m high the pressure increase at the arch (under specific hydrostatic pressure) was observed, at the beginning of the development, to be 145 atm at a depth of 2000 m; and at the Lakk deposits (France) it was 660 atm at a depth of 4000 m, etc.

These considerable excess pressures lead to an intensified injection of fluids into the covering rocks and cause the fluids to penetrate through the rocks, especially along the tectonic zones which define the shape of the so-called intrusion halo. The abnormality decreases substantially from the arch to the periphery and, as a result, the infiltration of fluids into the overlying rocks slows down.

Because the structure of the arch of a deposit is more prone to disruption by faults than are the wings of the deposit, the permeability of the arch is increased, which permits a more intensive intrusion of carbon dioxide and the water that accompanies it from the large deposits. It follows from this that the maximum gradient of porous pressure is observed just above the deposit, at the bottom of the covering layers. This has been confirmed, for example, from experience of extraction from the Karadag deposits, where, in the arches of wells, a lowering of the density of the drilling mud from 2.3 - 1.75 $g/cm^3$ led to the occurrence of gas and blowouts, whilst at the same time the sinking of other wells in the area proceeded normally using mud of a density of 7.4 → 1.45 $g/cm^3$.

When deposits occur in complex geological structures which may be classified into blocks having different absolute markings, the type of distribution of abnormalities of formation pressure may differ in each block. Usually, however, some general features may be noted for AHFPs: they tend to increase rapidly at the top of the deposits (in the intrusion halo) and then (within the limit of the massive large deposits) their growth decreases significantly, with a fall in the gradient to a minimum at the bottom of the deposits, this being due to a vertical migration of fluids through covering layers that are difficult to permeate. The theoretical basis for this phenomenon has been discussed for the first time in ref. [5].

The presence of IFP and AHFP require the utilization of more concentrated drilling fluids, with an increased content of solid phase material, which, often in combination with complex geological conditions (such as the block construction of deposits) can complicate the process of well drilling if the IFP and AHFP have not been sufficiently studied.

The creation of significant fluctuations in the pressures of the well-bed when concentrated water-based muds are used often leads to the absorption of the drilling fluids, the cave-in of unstable clays, the shrinking of the borehole, the trapping of pipes, and other accidents. The increase in the concentration of the mud, used to suppress AHFP at greater depths, often produces difficulties in the control of the fluctuations in the pressure of the borehole, self-induced hydro-ruptures of weak layers, and an increasing risk of the absorptions that accompany blowouts.

It should be noted that, as a rule considerable expenditure of materials, time, and effort are required to bring these problems under control. Take, for example, the drilling of one of the exploratory wells in the district of Tadjikistan, at a depth of more than 2200 m, in water-bearing sandstone with a formation pressure of over 400 kg/cm$^2$. During a period when water was being released from the wall, the intermediate column was disturbed at a depth of approximately 1200 m, thus making it impossible to seal off the well. Over a long period, the well emitted highly mineralized water of a concentration of approximately 1.19 g/cm$^3$ at a rate of approximately 8.5 thousand m$^3$ daily, and at a temperature of 92-94$^\circ$C; to drain off this water, it was necessary to drill a special inclined well.

If the drilling pressures used are a good deal higher than the porous pressures of the rock types encountered (especially clays), the mechanical rate of drilling is greatly reduced; this complicates still further the equipment of wells in the AHFP zones.

This shows the urgent need for timely forecasting of both the presence of zones of IFP and AHFP and also their magnitudes, so that the feasibility of boring wells under conditions close to the equilibrium pressure of the borehole can be assessed [2,4].

For such forecasts it is important to study the laws governing the gradients of formation pressure and the intensity of the vertical migration of fluids; such forecasts should also take into account any signs of the active influence of large-scale accumulations of fluids bounded by strata with excessively high energy, particularly for clay layers, in which, as a result of this effect, condensed zones (intrusion haloes) are formed on increasing the drilling pressure. In these zones the following phenomena are observed: increased heating, the appearance of montmorillonite-hydromica neogenesis, the pressure of siliceous limestone lithological barriers, the development of condensed (desalinated) waters in the intrusion haloes under gas-condensate accumulations, etc. [2].

It has been shown experimentally [12] that, when dolomite, lime, sodium salts, and several other mineral salts available in the intermediate layers in clays are added to the drilling mud, argillite is turned into plastic montmorillonite. During the active absorption of water by the montmorillonites, a swelling of an osmotic character takes place [7]. Montmorillonite in the intrusion haloes becomes saturated with water due to the presence of condensed (desalinated) water and carbon dioxide. This effect is used in practice to strengthen the walls of wells in the zones where they pass through the intrusion halo, but at the expense of the precise regulation of the salt composition of the water phase of special oil emulsions that are used as a flushing fluid during drilling.

For the drilling of wells under conditions where the formation (porous) pressure and the hydrostatic pressure are close to equilibrium, it is necessary to determine the zone of development of AHFP over a period of time and to perform a quantitative evaluation of the formation pressures. With these objectives in mind, a number of methods have been devised in the U.S.S.R. and in other countries. The methods are based on the use of parameters and characteristics noted during observation of the drilling process, and on the results of the analysis of drill cores and bore-mud, aided by field studies of the mud at the mouth of the well. In addition, the variables chosen for observation should reflect the changes indicated above, at the relevant depth for each parameter, under conditions caused by prolonged and active AHFP.

In solving the problem outlined above, one should take into account two possibilities concerning the nature of the covering layers, namely, whether they are composed of clay or of tightly packed impermeable salts or anydrates.

Before drilling, an attempt is made to forecast the presence of deposits with an abnormally high formation energy, with the objective of choosing the correct design of well for the local pressure conditions; this type of forecast is generally based on the interpretation of geological, geophysical, and geochemical data for the region and area concerned. In cases where the deposit has not received sufficient study, the necessary data may be obtained with the help of seismic surveys of the intrusion haloes and the rest of the deposit in combination with quantitative methods involving direct geochemical studies, gravitational prospecting, etc.

During the drilling process, a continuing approximate forecast of the reserves of AHFP and their quantitative significance may be produced by observing all of the parameters indicated above.

For the clay layers, all of the means of evaluation of AHFP are based first on determining the normal relationships between the density of the layers and the depths concerned, and then on checking for specific layers in which these relationships are violated. The decompaction of clays in the intrusion halo, under the influence of AHFP, leads to a decrease in their mechanical strength and density as well as to an increase in their porosity. In addition, it is found that the electrical resistance and the speed of the propogation of the resilient waves decrease, the gaseous content increases, etc.

In order to predict the appearance of zones of AHFP and to evaluate the relevant formation pressures the following parameters and characteristics may be used:

1. DATA FROM BORING [1,6]

This may be divided into three groups:

1.1 Methods based on the occurrence of gas-collecting layers which have a pressure higher than the pressure in the wells; this manifests itself in an increase in gas saturation of the drilling mud and the changes in the pressures at the outlet of the drilling pump; also, if mineralized waters are encountered, the content of salts in the flushing fluid increases;

1.2 Methods based on the occurrence of clays which have a porous pressure higher than the hydrostatic pressure in the well; if these unstable rock types are encountered during drilling, they flow into the borehole, leading to an increase in drilling torque and delays in the raising and lowering of the drilling column; frequently, the expulsion of an increased amount of fragmented bore mud from the well is observed;

1.3 Methods based on noting the increase in the vertical rate of drilling when passing through the intrusion halo; this is particularly evident in zones where there is a difference in the porous and the hydrostatic pressures in the well (sometimes as large as 35 $kg/cm^2$). The drilling rate reaches a maximum when the two pressures are at equilibrium, but the axis loads are fixed according to the type of drill, its rate of rotation, and its vertical drilling rate. The resulting data are processed according to the exponential method [11], taking the density of the flushing liquid into account.

2. RESULTS FROM ANALYSES

The results of analyses of the bore mud and core samples in terms of their density, porosity, degree of saturation with fluids and electrical resistance, and studies of the speed with which the horizontal waves are propagated in the samples, and of their elastic deformation characteristics. The last method is particularly useful for forecasting AHFP in the presence of thick covering layers of salts and anhydrates.

3. HYDROPHYSICAL STUDIES [1,3,8,9]

Hydrophysical studies are made at all stages in the exploration of deposits (especially seismology and gravimetry) and wells (logging of electrical, induction, acoustic, and density data); geophysical methods are especially useful for sandstone-clay sections. Graphs are available which show how these physical properties normally vary with depth: layers with a normal porous pressure can be matched to the depth dependencies shown in the graphs, and any remaining deviations from these dependencies (e.g., a lowering of the relative electrical resistance or density of the rock types, or an increase in their conductivity) are evidence of the presence of AHFP. The methods generally used [1] for determining porous pressure from geophysical data and the study of the bore mud take into account the influence of the temperature of the rock types considered, the degree of mineralization of the muds, and the change of petro-physical properties under the influence of AHFP. The actual calculation of porous pressures is carried out by reducing the values that characterize the layer being studied, to those at an equivalent depth under specific hydrostatic pressure this considerably simplifies the calculation procedure and lowers the error in the evaluation of the pressure.

4. GEOCHEMICAL STUDIES

Geochemical studies of the bore mud and the filtrates of drilling muds [1,3]. It has been established that, in comparison to the general background values, the zones of AHFP show an increase in pH and geothermic gradient, and a significant decrease in oxidation reduction (redox) potential.

The most successful forecasts of the appearance and magnitude of AHFP have been obtained by using a complex co-application of all the methods described above.

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