APPLICATIONS OF AEROSPACE TECHNOLOGY TO PETROLEUM EXPLORATION

Study Report

Volume 2: Appendixes

Sponsored by
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Office of Energy Programs

Prepared by
JET PROPULSION LABORATORY
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PREFACE

This document is Volume 2 of two volumes which report the work carried out in a study of petroleum exploration problems and their solutions through possible applications of aerospace technology. Volume I includes an executive summary, findings and recommendations, and a description of the work done in the study. It presents and discusses a number of concepts that may help solve certain identified problems. This volume contains appendices which go into greater depth on various aspects of the study. This work was performed under contract to the National Aeronautics and Space Administration (Contract NAS7-100).

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APPENDIX B

TYPES OF QUESTIONS ASKED IN TASK 1

(In Task 1 interviews, individuals from petroleum companies were asked questions along the lines of those listed below. Individuals from service companies were asked questions along the lines of those marked with asterisks.)

1. What factors do you consider most important in making management decisions about exploration?

2. What are the most important problems of economic analysis in exploration?

3.* what do you consider important operational problems in exploration? (difficulties in carrying out exploration activities in the field).

4.* What do you consider the most important technical problems in exploration?

5. Where do you draw the line between exploration and production? In particular, in which category do you put flow tests of discovery wells, drilling of stepout wells, reservoir analysis?

6.* What do you think of the suggestion of a two-day get-together of people from oil and service companies with aerospace people to help reach consensus on what exploration problems might benefit from application of aerospace techniques?

7. Would you be willing to let us hear or see a presentation of the kind usually made to your exploration management as a basis for an exploration decision (such as a decision to drill an exploratory well or to take a lease)?

8. What are the most important factors in your decision to a) run a geophysical survey? b) lease? c) drill an exploratory well?

9.* Do any instances occur to you in which techniques used in aerospace work might help in exploration?

10.* Would you be willing to work with us further in attempting to identify such instances?

11.* What are the areas of exploration technology (hardware, analytical tools, logistics) that could benefit the most from the application of aerospace technology? Which areas would yield the highest dividend in terms of reduction of time and cost of exploration and improving the success ratio of new exploration?

APPENDIX C

EVALUATION CATEGORIES FOR SUGGESTED PROBLEMS IN TASK 1

The problems suggested by the petroleum exploration industry were, after initial editing and categorization (Table 2 of Volume 1), evaluated according to five criteria. These criteria were pertinence (to petroleum exploration), location (geographic), significance, matching aerospace technology, and probability of solution within 5 years.

The classifications under these five criteria are as follows:

Pertinence

1. Pertains to petroleum exploration.
2. Pertains to petroleum production and/or development only.
3. Pertains to nonpetroleum applications only (e.g., minerals, mining, geothermal).

Location

1. Off shore.
2. On shore, U. S.
3. On shore, foreign only.

Significance

1. Highly significant: solution may lead to major increase in petroleum found or to major decrease in total cost of exploration.
2. Not highly significant: solution unlikely to lead to major increase in petroleum found or to major decrease in total cost of exploration.

Technology

1. Matching aerospace technology identified.
2. Matching aerospace technology not identified.

Solution Within 5 Years

1. Likely.
2. Unlikely.

In Appendix D, which follows, each problem is discussed briefly. Its evaluation classification is given in short form, numerically and in words, in the order listed above. An example follows:

1/1/1/1/1: Exploration/Off shore/Highly significant/Aerospace technology identified/Solution likely within 5 years.

Locations coded as /1,2/ mean both "Off shore" and "On shore, U.S.," or, more generally, "any location."

APPENDIX D

TASK 1 PROBLEM DESCRIPTIONS AND EVALUATIONS*

The 59 problems remaining after combining similar problems suggested by industry are described and evaluated in this appendix. In the evaluations of this appendix, the last entry is a numerical and verbal summary based upon the defined criteria, using the categories outlined in Appendix C. The problem listing below is identical with Table 2 in the text.

*The descriptions and evaluations in this appendix are those prepared in Task 1. They do not reflect the subsequent, more detailed, examination of selected topics in Task 2.

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(1) Topographic mapping of large areas of sea bottom

A. Problem: Need topographic maps of large areas of sea bottom at resolution comparable to Landsat imagery of land areas.

B. Present technique: Individual seismic lines or side-looking sonar traces are used, giving only lines or narrow bands of topographic data. Data are presented as strip-chart or equivalent; no quality images or maps are produced.

C. Need/significance: There are four significant benefits in having topographic maps of the sea floor:

1) Geologists can use such data for base maps and to map sea-floor geology. The recognition of structures such as faults and possible folds (anticlines, domes, synclines) would provide valuable information for petroleum exploration, much as topographic data on land is utilized.

2) Topographic data can indicate likely outcrops. These are important as providing a convenient source of samples for age-dating and other measurements.

3) Engineers would use such maps to plan better locations for drill platforms and other bottom-reaching structures.

4) Topographic maps could be used for locating or relocating positions at sea.

Moderate significance for exploration.

D. Matching aerospace technology: Data processing and display. Many measurements already exist that have not been compiled into maps. Better forms of display can be provided. Computer contouring of seismic data to produce pseudo-topographic maps is presently possible. Programs exist to insert an artificial sun at any desired position to produce shadowing effects useful for structural interpretation. Computer or analog processing of side-looking sonar can provide high-quality images and maps. With this capability, side-looking sonar with range of tens of kilometers may lead to maps at reasonable cost.

E. Likelihood of solution within 5 years: Good likelihood of proving technical feasibility.

F. Evaluation: 1/1/2/1/1: Exploration/Off shore/Not highly significant/Aerospace technology identified/Solution likely within 5 years.

(2) Determining why a shale layer is a good source rock in one area and not in another area close by

A.	Problem:	This is a very general question dealing with many aspects of oil formation. The factors influencing production of a source rock are abundance of organic material (phytoplankton), depositional currents, bottom topography, location (river mouths, coastal zones, shoal waters, upwelling areas are favored). A slight change in any of these factors at the time of deposition of the source rock could change the amount of oil potentially existent.
B.	Present technique:	Reconstruction of depositional environment is of foremost importance. Determination of climate, current directions, salinity, topography, and distance from land are now being used. These are found by analysis of the being from both macro-observations and micro-observations.
C.	Need/ significance;	Highly significant. If a rock could be accurately evaluated as to potential source rock quality, much effort would be saved in needless exploration for a reservoir.
D.	Matching aerospace technology:	None identified.
E.	Likelihood of solution within 5 years:	Poor.
F.	Evaluation:	1/1,2/1/2/2: Exploration/Any location/Highly significant/ Aerospace technology not identified/Solution unlikely within 5 years.

(3) Mapping stratigraphy with occasional holes for control

A.	Problem:	Very often seismic-reflection data are available over an area of interest in which a few holes have been drilled and logged. How can the seismic data and the bore-hole data best be tied together to map stratigraphy over the area?
B.	Present technique:	Geologists and geophysicists use their best judgment in interpreting and combining the two kinds of data. Petrological and paleontological data from cores, logging data, and geophysical measurements from the surface are used to identify time/lithological horizons and to guide geophysical interpretations.
C.	Need/ significance:	This problem arises in most areas of interest where one or more stratigraphic or other holes have been drilled. It is very important in that the map produced is the basis for deciding if and where to try additional drilling. Significant in affecting whether or not oil is discovered and in affecting cost of the exploration effort.
D.	Matching aerospace technology:	For tie-in itself: data processing. It is not clear that aerospace data-processing techniques can aid the tie-in any more than petroleum industry techniques. An indirect but important approach is through improving the seismic data (see Problems 8-10, 16, and 20).
E.	Likelihood of solution within 5 years:	Gradual progress expected.
F.	Evaluation:	1/1,2/1/2/2: Exploration/Any location/Highly significant/ Aerospace technology not identified/solution unlikely within 5 years.

(4) Computer programs to recognize lineaments on images

A.	Problem:	Lineaments are linear features recognized on an image. They may represent geological features, cultural features, vegetation patterns, or artifacts. Lineaments corresponding to geologic structure (faults, fractures, jointing) are important in that they can control fluid migrations, or delineate stratigraphic traps (fault control), mineralization sites, etc.
B.	Present technique:	Observation of the images (aerial photos, radar images, satellite images, or sonar records) by a photogeologist. The major problem in identification of lineaments is the subjectivity of the analyst in picking a feature in an image (Ref. D-1)* and then in assigning it specific geological significance.
C.	Need/ significance:	Might lead to finding more petroleum, but the value of computer recognition is not clear. Moderate significance.
D.	Matching aerospace technology:	Computer pattern recognition. Some work on the problem is starting under NASA sponsorship.
E.	Likelihood of solution within 5 years:	Good.
F.	Evaluation:	1/1,2/2/1/1: Exploration/Any location/Not highly significant/Aerospace technology identified/Solution likely within 5 years.

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*References are listed at the end of this appendix.

(5) Detecting surface geological expression of possible traps

A.	Problem:	Better ways of detecting and identifying the surface geological expression of a possible subsurface petroleum trap.
B.	Present technique:	Surface observations, aerial photographs, and resulting geological maps are used by geologists who attempt to recognize pertinent characteristics such as abrupt change of drainage patterns, growth structures, different erosional history from surrounding lithology, etc. Satellite pictures are beginning to be used as an additional source of data.
C.	Need/ significance:	Better techniques should result in finding more oil and reducing exploration costs. Significant.
D.	Matching aerospace	Data processing, especially image enhancement; aircraft; satellites; remote sensing. Work sponsored by NASA and others on techniques of digital enhancement of Landsat imagery and interpretation of the enhanced pictures is underway. Some work is under way on computer-aided analysis of features found on such pictures. Also helpful would be satellite imagery with better spatial resolution; this planned for future Landsats. Aircraft and satellite techniques appear limited to land areas only. For offshore areas, more and better topographic mapping of the sea floor might provide data (see Problem 1).
E.	Likelihood of solution within 5 years:	Gradual improvements likely.
F.	Evaluation:	1/1,2/1/1/2: Exploration/Any location/High significant/ Aerospace technology identified/Solution likely within 5 years.

(6) Geographic location at sea

A.	Problem:	More accurate geographic location at sea is needed: position measurements with an accuracy of 30-50 feet from a moving ship. Required is either absolute location or at least a way to relocate several years later.
B.	Present technique:	Use satellite navigation (TRANET) system for control, interpolating between fixes with doppler sonar, Decca, or LORAN C. Satellite fixes are sufficiently accurate but available only one per 90-minute satellite orbit. Interpolation accuracy with present technique is stated to be about 200 feet, not accurate enough.
C.	Need/ significance:	Seismic surveys are taken from a moving ship; several years later, it may be desired to drill a well on the basis of the seismic data. Inaccuracy in locating the hole relative to the survey may cause failure to find oil, and waste of money in drilling a dry hole or in not utilizing the survey to best advantage. Moderate significance.
D.	Matching aerospace technology:	Satellite navigation, inertial navigation. Inertial navigation systems that may provide the desired interpolation accuracy are commercially available for about $500,000. Declassification of some military equipment may lead to cheaper commercial equipment. Also, the accuracy of satellite fixes is marginal; some improvement may be possible depending on the number of terms of the satellite orbital ephemerides available on an unclassified basis. Problem best handled with commercial manufacturers of navigation equipment and Department of Defense.
E.	Likelihood of solution within 5 years:	Good.
F.	Evaluation:	1/1/2/1/1: Exploration/Off shore/Significance not high/Aerospace technology identified/Solution likely within 5 years.

(7) Geographic positioning on land

A. Problem: In some areas, particularly jungles, locating position is difficult.

B. Present technique: Benchmark and transit; tape, tellurometer or geodimeter; aerial photography. Celestial observations for control. The accuracy of these controls is limited and celestial observations cannot be made readily through tree cover. Transit and geodimeter (optical ranging) require optical lines-of-sight, difficult to obtain in dense growth; the geodimeter (microwave ranging) has limited distance capability in dense growth. Magnetic compass readings are often affected by local magnetic deposits. Benchmarks are difficult to relocate in a jungle. Landmarks for aerial photography are often but not always available.

C. Need/ significance: The position of lease boundaries needs to be known on the ground; this may require absolute measurements of positions. Relative location of points in a survey is needed. Also required is a way of locating survey positions years later, if, for example, it is decided to drill a well on the basis of the survey. Difficulties in these measurements increase exploration cost. Significance: moderate.

D. Matching aerospace technology: Satellite navigation; radio navigation. Satellite navigation systems give good absolute positions. For relative positions, radio-doppler ranging to a helicopter could be employed or a beacon tracking system using microwaves or light from hilltops or above treetops to helicopters or to other treetop locations. Could probably be handled by commerical suppliers.

E. Likelihood of solution within 5 years: Good.

F. Evaluation: 1/3/2/1/1: Exploration/Foreign/Not high significance/ Aerospace technology identified/Solution likely within 5 years.

(8) Finding and identifying thin beds

A.	Problem:	Better ways of finding beds less than 100-feet thick and identifying them as sand or shale.
B.	Present technique:	Reflection seismology.
C.	Need/ significance:	Most oil-bearing strata are less than 100-feet thick. Present seismic techniques often miss these thin beds. Very significant.
D.	Matching aerospace technology:	Possible approaches: improved seismic sources and improved data processing. Strong sources of the higher frequencies (100 - 200 Hz or somewhat more) are needed to permit higher resolution. Improved sources are discussed in Problem 10 (matching technology: vibration analysis; vibration and shock testing; solid-propellent technology; thrust-engine design, unstabilities, and transients; combustion aerodynamics). Improved data processing to utilize the resolution possible is discussed in Problems 16-20.
E.	Likelihood of solution within 5 years:	Good likelihood of proving technical feasibility.
F.	Evaluation:	1/1,2/1/1/1: Exploration/Any location/High significance/ Aerospace technology identified/Solution likely within 5 years.

(9) Improved detection of stratigraphic traps

A.	Problem:	Location of stratigraphic traps.
B.	Present technique:	Seismic techniques, direct drilling, surface geologic mapping. Stratigraphic traps are difficult to find (as compared with structurally controlled traps) since the contrasts in seismic velocity between reservoir and surround are often low because of the subtle stratigraphic complications present. Oil and exploration companies have traditionally concentrated on location of structural traps because of the relative ease of doing so. Oil companies <u>do</u> look for stratigraphic traps, and some have substantial production from them. A possible difficulty is that contracted seismic surveys are paid for by the mile; this encourages speed in surveying, possibly at the expense of care.
C.	Need/ significance:	It is thought by some experts that significant continental resources remain to be discovered in these types of reservoirs. High significance.
D.	Matching aerospace technology:	Possibly improved seismic data analysis and synthesis with other geological information.
E.	Likelihood of solution within 5 years:	Fair to good, depending on the exploration and interpretation effort made. The assumption here is that necessary tools are available; required now are careful measurements and analysis.
F.	Evaluation:	1/1,2/1/1/1,2: Exploration/Any location/Significance high/Aerospace technology identified/Likelihood of solution within 5 years uncertain.

(10) Improved seismic sources

A. Problem: Needed for both land and sea work are better seismic sources; in particular, sources that provide more energy and wider frequency band than present sources. For land use, better portability and lower costs than with present sources are needed. Desired frequency band about 4 Hz to 150 Hz, probably white. If impulsive source, should be minimum-delay.

B. Present technique: Explosives, electric sparkers, gas exploders, air guns, magneto-hydrodynamic bangers, dropped weights, water hammers, and underwater steam calliopes, all of which are impulsive sources. In addition, there are variable-frequency hydropneumatic and electrical systems. The energy range from the strongest to the weakest source mentioned is over 100,000:1. With the weaker sources, it is necessary to resort to multiple source/receiver arrays, vertical stacking, and common reflection point (CRP) stacking to build up the reflection signal/noise ratio to required levels. The frequency range of currently available frequency-modulated systems is about 4 Hz to 100 Hz.

C. Need/significance: For seismic exploration, need to provide better signal/noise ratio and so better data especially at considerable depths. Low frequencies can penetrate subsurface strata better, but ambient noise, surface waves, and surface-mode resonances are greater at these frequencies. For resolving thin beds, high-frequency (>100 Hz) signals are needed. Improved signal/noise ratio of recorded seismograms should lead to easier detection of stratigraphic traps as well as more precise knowledge of subsurface stratigraphy, which should reduce the need for drilling and lead to a better success ratio for exploratory wells. A more portable, easy-to-use, and cheaper seismic source would lower the cost of land seismic surveys. Very significant problem.

D. Matching aerospace technology: Engine combustion; variable-thrust, unstably burning or pulsed thrust engines; high-temperature, high-speed aerodynamics; pyrotechnics, vibration testing; phased arrays; aircraft. Among possible approaches are

1) Explosives tailored to produce less useless and damaging high-frequency energy than dynamite; more energy into frequencies of seismic interest.

2) Solid-propellant charges tailored to generate frequencies needed.

3) Thrust engines (thrusting downward against ground) with thrust varying at frequencies needed.

4) Sonic booms.

E. Likelihood of solution within 5 years: Good likelihood of proving technical feasibility of one or more methods.

F. Evaluation: 1/1,2/1/1/1: Exploration/Any location/High significance/Aerospace technology identified/Solution likely within 5 years.

(11) Seismic prospecting through highly attenuating or highly reflecting layers

A.	Problem definition:	Seismic exploration has a severe signal/noise problem when a highly reflecting layer (with respect to the incident seismic radiation) overlies horizons of interest. An example of this situation is basaltic lava flows in the southwest. A similar problem is encountered with a highly lossy layer, such as clastic volcanics or a deep weathered layer, which absorbs much of the incident seismic energy. Mountain fronts also pose problems by giving large side reflection.
B.	Present technique:	The present approaches concentrate on using more incident energy from stronger seismic sources or enhancing the signal/noise ratio by the use of larger number of geophones in a carefully designed array. Also used are data-processing techniques that discriminate against resonances.
C.	Matching aerospace technology:	Data processing and technology associated with possible seismic sources: vibration analysis; vibration and shock testing; solid-propellant design; thrust-engine design, instabilities, and transients; combustion aerodynamics; phased arrays. Possible approaches: (1) Better seismic sources and phased source arrays; see Problem 10. (2) Better seismic data processing; see Problems 16-20.
E.	Likelihood of solution within 5 years:	Likelihood of proving technical feasibility in this time is fairly good.
F.	Evaluation:	1/1,2/1/1/1: Exploration/Any location/High significance/ Aerospace technology identified/Solution likely within 5 years.

(12) Seismic data transmission from sensors to recorder

A.	Problem:	Seismic signal transmission from hydrophones and geophones to recorder is noisy and is troublesome due to lead breakage, leakage, and other problems.
B.	Present technique:	Wire pairs interconnect up to 50 phones per phone-group; up to several hundred pairs of leads (channels) come from phone-groups to recorder on ship or truck. Multiplexing is sometimes used. Each channel is digitized and recorded.
C.	Need and significance:	Cable (or lead) breakage opens circuit between phones and recorder. This break must be repaired before survey can proceed. The problem causes survey delays and significant cost increases. Noise pickup degrades the quality of the data and hence of the results. Moderate to high significance.
D.	Matching aerospace technology:	Two approaches are possible, digital and analog. Each eliminates multiple leads and uses one or a few coaxial cables. This problem cannot be considered independently of the problem of getting data from ship or truck to data analysis center (Problem 13) because of the interaction between them. The solution to the latter problem will affect the approach to this one and vice versa.
E.	Likelihood of solution within 5 years:	High
F.	Evaluation:	1/1,2/1,2/1/1: Exploration/Any location/Moderate-high significance/Aerospace technology identified/ Solution likely within 5 years.

(13) Seismic data transmission from survey ship to home office

A.	Problem:	Survey ships accumulate large quantities of seismic data on magnetic tape which must be returned to a processing center for reduction and analysis. Ship size and living conditions are not conducive to extensive on-board analysis. A long (5 days to a month) turn-around time for data analysis is now required to determine if all recording went properly and if another look is needed at some area. Resurvey of any area is costly, and accuracy of positioning may be inadequate for subsequent runs. Ships may be located anywhere in the world; and data-analysis centers are located in the continental U.S. and in a few other countries.
B.	Present Technique:	Seismic data are digitized and recorded on magnetic tape. Tapes may be picked up daily or weekly and flown back to a processing center for analysis, or tapes may be kept onboard until the end of a month's cruise and then sent to the processing center.
C.	Need/ significance:	Near-real time reduction and analysis of data will permit quick detection of malfunctioning equipment and allow changes in the survey if promising results appear in one area. Analysis at the home office of the company will permit the most experienced analyst to examine the data without leaving the office. Cost reductions will accrue in avoiding the need of sending a ship back for resurvey and, more importantly, in avoiding drilling of dry holes because of inadequate surveys. Better surveys should lead to finding more oil. Moderate to high significance.
D.	Matching aerospace technology:	Transmission of data by radio relay via a nearby shore station or, for distant operations, by satellite, to the home office. Off the U. S. coast, transmission to shore and then via commercial broad-band data link should be possible. For foreign operations, Marisat will be available later this year, and techniques can be evolved to make maximum use of this satellite. Consideration can be given to provision of dedicated facilities on future communication satellites or of communication satellites dedicated to petroleum exploration. Data compression and, on radio links, coding for secrecy will probably be desireable.
E.	Probability of solution within 5 years:	Technical feasibility proven. Economic and regulatory feasibility can be determined within 5 years.
F.	Evaluation:	1/1,2/1,2/1/1: Exploration/Any location/Moderate-high significance/Aerospace technology identified/ Solution likely within 5 years.

(14) Marine seismic cable jackets

A. Problem: Hydrophone cables used in marine seismic surveys are typically 3 miles long and subjected to abuse from salt water, wave action, filling oil, deck handling, fungus attack, and sea animals. Cable-jacket wear and leakage results in expensive repairs or replacement and causes expensive time delays. Needed is a better high-strength material which is flexible, transparent, abrasion resistance, and stands up to the marine environment.

B. Present technique: Present cables are typically 3-4 inches in diameter with a clear polymer jacket. A clear jacket is used to detect air bubbles within the filling oil which affect buoyancy and to allow the wiring to be inspected. The cables are constructed in 100-meter lengths and use electrical connectors to assemble cables of the desired length. Cables are coiled on the ship deck or are stored in large reels when not in use. When cable sections break or leak, the whole cable must be retrieved, the problem section removed, and shipboard repairs performed or the cable returned to the manufacturer for repair.

C. Need/significance: This problem has little impact on the rate of discovery of oil but does have some effect on exploration costs. A better high-strength material which stands up to the environment and is flexible and transparent would assist the exploration effort.

D. Matching aerospace technology: None identified that are not already commercially available. Aerospace materials engineers could help in specifying jacket material but so could other materials consultants.

E. Likelihood of solution within 5 years: Moderate.

F. Evaluation: 1/1/2/2/1: Exploration/Off shore/Not high significant/ No aerospace technology identified/Solution within 5 years moderately likely.

(15) Faster seismic-processing turnaround

A.	Problem:	Service companies may take 2 weeks or more to output seismic processing to petroleum companies.
B.	Present technique:	Service companies process data in the order received. It is probably in the interest of service companies to insure some backlog of work so that their equipment and staff will not be idle.
C.	Need/ significance:	Oil company actions may be delayed by the wait. Survey crews may have left the area so there may be extra expense if the processed data indicate that more measurements are needed. Because of the extra expense and scheduling problems, the additional measurements may be skipped; the decision whether to drill may then be made without them. Correcting the problem could reduce cost and lead to finding more oil.
D.	Matching aerospace technology:	No identified aerospace technology. An agreement between oil company and data-processing service company that an extra fee would be paid for prompt service might help.
E.	Likelihood of solution within 5 years:	Good.
F.	Evaluation:	1/1,2/2/2/1: Exploration/Any location/Significance not high/No aerospace technology identified/Solution likely within 5 years.

(16) Weathered-layer effects on seismic-reflection data

A.	Problem:	Dry loose material with high acoustic scattering and very low-acoustic velocity typically extends from the land surface to a depth of ten to hundreds of feet. Multiple scattering of seismic signals by the top and bottom of the weathered layer and by inhomogeneities within it produce "noise" that obscures the signal received from the deeper layers of interest. Time delays associated with thickness changes and near-surface inhomogeneities of the weathered layer disrupt trace-to-trace alignment of seismic-reflection records and processing of seismic-reflection data.
B.	Present technique:	Trace-stacking and filtering methods are used to discriminate against multiple scattering and improve signal/noise ratio. Static corrections are used to remove signal time variations introduced by the weathered layer. The correction is a constant time delay assumed applicable to the entire record from one geophone group, and assumed to be the sum of a contribution characteristic of the source position and a contribution characteristic of the receiver position. The validity of the assumptions underlying the static connection is in dispute.
C.	Need/ significance:	Reflection seismometry is the most important surface technique used for petroleum exploration. Weathered layer "noise" and corrections significantly degrade the output. Improvements could lead to finding more petroleum and save considerable money in unsuccess ful drilling. Very significant problem.
D.	Matching aerospace technology:	Data processing. A possible approach is outlined in Problem 20.
E.	Likelihood of solution within 5 years:	Good likelihood of proving technical feasibility.
F.	Evaluation:	1/2/1/1/1: Exploration/On shore/High significance/ Aerospace technology identified/Solution likely within 5 years.

(17) Multiple reflections from sea bottom and surface

A.	Problem:	In many areas strong multiple seismic reflections occur from sea bottom and sea surface and obscure seismic records of deeper features of interest.
B.	Present technique:	Stacking and filtering. See Problem 16.
C.	Need/ significance;	Even with present techniques, multiple reflections may seriously interfere with seismic interpretation. Significant.
D.	Matching aerospace technology:	Data processing. One approach is suggested in Problem 20.
E.	Likelihood of solution within 5 years:	Fair.
F.	Evaluation:	1/1/2/1/2: Exploration/Off shore/Significance not high/Aerospace technology identified/Solution unlikely within 5 years.

(18) Improved displays of processed seismic data

A.	Problem:	Seismic-processing systems provide such large quantities of output and in such formats that it is difficult for the human interpreter to digest and analyze it.
B.	Present technique:	Wiggle trace, variable area, variable density, zero-crossing, and other displays, sometimes with the aid of color.
C.	Need/ significance:	If the interpreter is overwhelmed with data, he cannot do a proper job of interpretation. Moderately significant.
D.	Matching aerospace technology:	Human factors engineering; image processing; pattern recognition.
E.	Likelihood of solution within 5 years:	Good.
F.	Evaluation:	1/1,2/2/1/1: Exploration/On shore/Not highly significant/Aerospace technology identified/Solution likely with 5 years.

(19) Porosity and permeability determinations from seismic data

A.	Problem:	How to determine porosity and permeability from seismic data.
B.	Present approach:	The porosity of a bed can be estimated from seismic velocity data if there is independent evidence of the lithology of the bed; for example, subsurface information from a nearby well. In such a case, the seismic data could be used to estimate variation in porosity along the bed. Very crude empirical estimates of permeability can be made if the porosity and lithology of the bed are known.
C.	Need/ significance:	Petroleum reservoirs are porous rock beds capped by beds with very low permeability. The permeability of the reservoir is an important factor in determining how much and how rapidly petroleum can be obtained from it. Porosity and permeability are thus key in finding and evaluating petroleum deposits. If they could be determined from seismic data alone, exploration costs would be markedly decreased, and the amount of oil found markedly increased. Highly significant.
D.	Matching aerospace technology:	Data processing. Techniques that quantitatively determined seismic absorption as well as velocity could give an indication of probable porosity.
E.	Likelihood of solution within 5 years:	Likelihood of proving technical feasibility for porosity measurements fair, for permeability measurements poor.
F.	Evaluation:	For porosity: 1/1,2/1/1/2: Exploration/Any location/ Highly significant/Aerospace technology identified/ Solution unlikely within 5 years. For permeability: 1/1,2/1/2/2: Exploration/Any location/High significance/No aerospace technology identified/Solution unlikely within 5 years.

(20) Recognizing subsurface petroleum from surface measurements

A. Problem: Identifying petroleum in subsurface reservoirs from on-surface measurements.

B. Present technique: Seismic-reflection technique, analyzing amplitude and time data, "bright-spot" and "flat-spot" methods; observations of edge "diffraction". These methods are limited in resolution by limited high-frequency content of recorded signals. They are not truly direct, detecting certain features of acoustic interfaces rather than petroleum. Thus, acoustic interfaces arising from some other subsurface characteristics are sometimes difficult to distinguish from petroleum occurances.

C. Need/significance: A good direct method of exploration would greatly increase exploration efficiency, presumably allow determination of the existence of oil or gas accumulation and perhaps permit direct determination of reserves through estimate of reservoir discussions. Highly significant problem.

D. Matching aerospace technology: Possible approaches include greater use of down-hole gravimetry, improved seismic data processing, and improved seismic sources. Gravity measurements at top and bottom of bed give its density, indicating porosity and often suggesting oil or gas content. This is not an aerospace technique but an existing petroleum exploration technique not usually used. For improved seismic sources, see Problem 10 (matching technology: vibration analysis; vibration and shock testing; solid-propellant technology; thrust-engine design, instabilities and transients; combustion aerodynamics). For improved data processing, one concept is to consider the received signal at any instant by one geophone as representing contributions from reflections on a ellipsoid with its foci at source and geophone. Computer summing over all geophones and all time intervals could provide a two-dimensional image (Ref. D-2). This differs from the single-trace-plus-stacking approach now used in reflection seismometry and is analogous to the medical techniques of computerized axial X-ray tomography and echo ultrasound. Corrections are needed for velocity differences as in current seismic processing, and multiple reflection must be considered. Possible advantages include improved signal/noise ratio, leading to better amplitude information and better resolution.

E.	Likelihood of solution within 5 years:	Good likelihood of proving technical feasibility of improved seismic technique.
F.	Evaluation:	1/1,2/1/1/1: Exploration/Any location/Highly significant/Aerospace technology identified/Solution likely within 5 years.

(21) Seismic surveys from moving vehicle on land

A.	Problem:	Any methods of conducting seismic surveys on land from moving vehicles?
B.	Present technique:	Stop to deploy source, geophones, and cables; take a few readings; pick up equipment; move it; redeploy.
C.	Need/ significance:	Present land seismic surveys are an order of magnitude more expensive than marine surveys because so few readings can be taken per day. This limits the use of the data return from land seismic surveys, increases the overall exploration cost, and reduces the amount of oil found on land. Highly significant.
D.	Matching aerospace technology:	Expendable geophones with radios dropped from moving land- or air-vehicle. Seismic sources operating on moving land-vehicle or dropped from moving land- or air-vehicle.
E.	Likelihood of solution within 5 years:	Economic solution unlikely within this time.
F.	Evaluation:	1/2/1/1/2: Exploration/On shore/High significance/ Aerospace technology identified/Solution unlikely within 5 years.

(22) Comfort at sea

A.	Problem:	Geophysical survey ships are small, wet, slow, and uncomfortable. It takes a long time to move the ship from one survey area to another. The crew are exhausted by the time they reach a new area.
B.	Present technique:	Conventional surface ships.
C.	Need/ significance:	An exhausted crew is not likely to do an excellent survey. This reduces efficiency in finding oil and wastes money. Moderate significance.
D.	Matching aerospace technology:	Aviation; ground-effect vehicles; fluid dynamics. If the problem is serious enough that exploration companies would invest capital, hydrofoil vessels should be considered. Use of hydrofoils could shorten long uncomfortable voyages and increase availability of the vessels for surveys. Another possibility is air transport of most of the survey crew between areas, with time available for rest and relaxation. A third possibility is increased use of airborne reconnaissance (see Problem 47).
E.	Likelihood of solution within 5 years:	Good.
F.	Evaluation:	1/1/2/1/1: Exploration/Off shore/Significance not high/Aerospace technology identified/Solution likely within 5 years.

(23) Base camp logistics for remote land locations

A.	Problem:	Better means of providing shelter, food, comfort and supplies for survey crews in isolated land locations.
B.	Present technique:	Ship by sea, land transport, or air.
C.	Need/ significance:	Living conditions during survey operations in isolated locations are often unpleasant for the crew. Supply can be slow. Significance; moderate. Pertains primarily to foreign exploration.
D.	Matching aerospace technology:	Aviation. Possibly more use of helicopters to transfer supplies from nearest airstrip or harbor.
E.	Likelihood of solution within 5 years:	Some improvement expected.
F.	Evaluation:	1/3/2/1/2: Exploration/Foreign/Significance not high/Aerospace technology identified/Solution unlikely within 5 years.

(24) Storing magnetic and gravity data

A.	Problem:	Better ways of storing magnetic and gravity data especially aboard ship where large quantities of data may accumulate.
B.	Present technique:	In some cases, the data are stored on punched paper tape. This is bulky and fragile.
C.	Need/ significance:	Could reduce exploration cost slightly. Significance low.
D.	Matching aerospace technology:	Data handling. Possible approach: It appears that the data are already in digital form. A formatter could be constructed, utilizing micro-computer technology to record the data on reel-to-reel tapes, cassettes, or small magnetic discs. The cost of formatter plus cassette or disc drive is expected to be comparable to the cost of a good paper tape punch.
E.	Likelihood of solution within 5 years:	Very high.
F.	Evaluation:	1/1,2/2/1/1: Exploration/Any location/Significance not high/Aerospace technology identified/Solution likely within 5 years.

(25) Estimation of temperature at depth

A. Problem: Estimating temperature at depth from on-surface measurements. Estimating paleotemperatures.

B. Present technique: Measurements of near-surface thermal gradients and heat flow, extrapolating to obtain present temperatures at depth. Ocean-floor measurements, though better than other surface measurements, are often biased since they tend to be made at local low places. They are usually handicapped by lack of detailed knowledge of the local geology (i.e., structure, topography). These effects can lead to severe distortion of the near-surface temperature field, and lack of knowledge about them prevents corrections for the distorting effects. For estimating paleotemperatures, the degree of "metamorphism" of plant materials and the degree of charring of pollen grains are used.

C. Need/ significance: The thermal state of sedimentary basins governs the maturation, migration and ease of production of petroleum. Subsurface temperatures of about 140°F - 200°F are considered optimal for generation and migration of oil and gas; whereas, temperatures above approximately 300°F are ordinarily associated with gas occurrences. The temperature distribution can be used as a "frontier" exploration tool in special sites like Bering Sea, Alaska, etc. If the 300°F isothermal surface lies at, for example, 15,000 feet, occurrences below this depth are thought likely to be gas as opposed to oil. A. G. Fisher and S. Judson (Ref. D-3) suggest that thermal gradients are characteristic of various basin types, which have distinctive geologic histories. These approaches could enhance changes for petroleum discovery if the geologic history of various tectonic provinces were sufficiently well understood. Moderate significance.

D. Matching aerospace technology: Geophysical measurements; thermal control. There appears to be no way short of down-hole measurement of providing better extrapolation to depth. One means of improving the estimates would be to measure heat flow at a number of closely spaced points thus obtaining an average. No specific approach identified.

E. Likelihood of solution within 5 years: Progress expected but significant application within this time unlikely.

F. Evaluation: 1/1,2/2/2/1: Exploration/Any location/Significance not high/No aerospace technology identified/Solution unlikely within 5 years.

(26) Gravimetry from a moving ship

A.	Problem:	Gravimetric surveys of adequate precision cannot be made from a moving ship. Typical precisions are

Sea surface, moving or stationary ship:	1 milligal
Aircraft over sea:	1 milligal
Below sea surface; on bottom or on stationary or moving submarine:	10^{-1} milligal
On land:	10^{-2} milligal

B.	Present technique:	The usual procedure is to stop the ship, lower the gravimeter to the bottom, take a reading, raise the gravimeter, move the ship, and repeat. This greatly slows the survey and increases its cost. An alternative is to work from a moving ship, but the precision obtained is low.
C.	Need/ significance:	Gravity surveys are a useful reconnaissance tool in marine petroleum exploration. Reducing their cost and improving their precision would make them more useful and could lead to finding additional oil. Moderate significance.
D.	Matching aerospace technology:	Remote measurements. Possible approach: measurements on unmanned submersible, either towed or free-swimming. This apparently was suggested some years ago but never tried. For high accuracy of results will need to know, with high accuracy, the instrument depth as well as location, water density profile, tides, instrument velocity (for Coriolis correction), etc. Interpretation (inversion) to deduce mass distribution from gravity measurements is difficult but the same for sea as for land measurements.
E.	Likelihood of solution within 5 years:	Fair.
F.	Evaluation:	1/1/2/1/2: Exploration/Offshore/Significance not high/Aerospace technology identified/Solution unlikely within 5 years.

(27) Revival of old geophysical methods and development of new ones

A.	Problem:	Why are older geophysical methods, such as refraction seismometry, not being used much? Could new techniques permit reviving older methods effectively? Can new geophysical methods be developed and used effectively? Can long wave-length electromagnetic techniques be used for exploration?
B.	Present technique:	U. S. companies use primarily reflection seismometry, with a little gravity and magnetic for reconnaissance. Foreign companies use also some electrical, telluric and magnetotelluric methods plus some surface geochemistry and geobiology.
C.	Need/ significance:	Use of additional methods could lead to finding more petroleum and reducing cost. Moderately significant.
D.	Matching technology:	Geophysical measurements; data processing. No specific approach identified.
E.	Likelihood of solution within 5 years:	Fair.
F.	Evaluation:	1/1,2/2/2/2: Exploration/Any location/Significance not high/No aerospace technology identified/Solution not likely within 5 years.

(28) Improved logging method for detection of fractures

A.	Problem:	Better logging method to find tight fracture patterns tens of feet out into rock surrounding borehole and to measure their spacing and thickness.
B.	Present technique:	Camera, cores, and sonic log. Neither camera nor sonic log is good at showing tight fractures. Camera and cores are limited to the borehole; the borehole fracture pattern may be unrepresentative of surrounding material since drilling the hole and removing the core changes the stress pattern.
C.	Need/ significance:	Particularly in deep fine-grained reservoirs, fractures govern fluid flow and also the pattern of subsequent artificial fracturing. May also help initial reservoir assessment. Data on fracture patterns and thickness are needed to evaluate and plan secondary/tertiary recovery. Significantly affects cost of and recovery from secondary/tertiary recovery efforts. Moderate significance, mostly for extraction.
D.	Matching aerospace technology:	Possibly improved acoustic technique (sonar), emphasizing imaging. There may be some industry effort underway on this.
E.	Likelihood of solution within 5 years:	Good likelihood of proving technical feasibility.
F.	Evaluation:	2,1/1/2/2/1/1: Production and exploration/Any location/ Significance not high/Aerospace technology identified/ Solution likely within 5 years.

(29) Digital logging

A.	Problem:	Digital down-hole logging is needed
B.	Present technique:	Analog measurement and recording is common; the analog logs are cumbersome. Digitizing at the surface and digital recording are also available commercially.
C.	Need/ significance:	Would save effort and cost. Moderate significance.
D.	Matching aerospace technology:	Data handling. Possible approach: If down-hole digitization is worthwhile, design a micro-electronic analog-to-digital A/D converter and processor to fit into the down-hole instrument head. This would permit returning data to the surface over a 3-wire cable. High temperatures in deep wells may pose a design problem; one approach would be to use heat-absorbing phase-change salts to keep the electronics cool for some hours.
E.	Likelihood of solution within 5 years:	High.
F.	Evaluation:	1,2/1,2/2/1/1: Exploration and production/Any location/ Significance not high/Aerospace technology identified/ Solution likely within 5 years.

(30) Correcting well-logs for drilling-mud properties

A. Problem: The actual well-hole diameter and the wall porosity vary due to strata differences. The drilling mud that is within the hole and in the wall surface pores thus varies in thickness. This introduces errors in the well-log reading.

B. Present technique: These errors are either ignored or their effect is sometimes mitigated by mechanical means. In one logging system requiring electrical contact with the wall (very short measuring length), the electrodes are extended out through the mud to contact the wall directly. The mud contained in the pores of the wall still introduces a significant error in this case.

C. Need/significance: Higher quality well-logs will improve exploration (and production), reducing costs and probably increasing the amount of petroleum found. Moderate significance.

D. Matching aerospace technology: None identified.

E. Likelihood of solution within 5 years: Low.

F. Evaluation: 1,2/1,2/2/2/2: Exploration and production/Any location/ Significance not high/No aerospace technology identified/ Solution unlikely within 5 years.

(31) Measurements from bottom of hole during drilling

A.	Problem:	Providing measurements of drilling and geophysical parameters from the bottom of the hole during drilling, together with the required power supply.
B.	Present technique:	Although there are no commercial devices in use, the petroleum industry has several R&D projects in progress, working on techniques including use of drill pipe as an electrical conductor, using drilling fluid for hydraulic pulse transmission, and using the earth to transmit electrical signals.
C.	Need/ significance:	Monitoring down-hole parameters during drilling would lead to significant cost savings especially during exploration drilling. It would avoid some of the costly interruptions in drilling now needed to make measurements. Significant.
D.	Matching aerospace technology:	It is not clear how aerospace technology could provide assistance. One possibility is microwave transmission of data to the surface. The oil industry should be solving this problem since they have the expertise with the equipment and techniques. An ERDA laboratory may submit a proposal to ERDA.
E.	Likelihood of solution within 5 years:	Proof of technical feasibility of monitoring some parameters such as pressure and temperatures will probably be accomplished in 5 years. Formation logging will probably require much longer time to develop.
F.	Evaluation:	1,2/1,2/2/2/1: Exploration and production/Any location/ Significance not high/Aerospace technology not identified/ Solution likely within 5 years.

(32) Determining stratigraphy far out from borehole

A.	Problem:	Determination (mapping) of the surrounding stratigraphy thousands of feet out from a borehole or between two boreholes.
B.	Present technique:	Geological judgment, using borehole data and near-hole logs plus seismic-reflection data from surface. Down-hole radar is occasionally used to locate salt domes.
C.	Need/ significance:	To help in planning field development. Particularly needed are locations of buried sand bars, stream beds, and reefs. A good method should significantly reduce development costs and increase recovery. If data at depths greater than bore-hole depth can be obtained, it would be of great value in determining whether to continue drilling an exploratory hole. Very significant.
D.	Matching aerospace technology:	Acoustic time-delay spectroscopy between boreholes, or between a borehole and surface. Techniques for interpretation of the measurements will have to be developed. An alternative possibility is more careful detailed seismic-reflection measurements from the surface (see Problems 8-11, 16-20).
E.	Likelihood of solution within 5 years:	Proof of technical feasibility for measurement between boreholes, high. Between borehole and surface: fair.
F.	Evaluation:	Between boreholes: 2,1/1,2/1/1/1: Production and exploration/Any location/High significance/Aerospace technology identified/Solution likely within 5 years. Between borehole and surface: 2,1/1,2/1/1/2: As above, but solution not so likely within 5 years.

(33) Down-hole permeability measurement

A. Problem: A technique is needed to measure the permeability of formations downhole.

B. Present technique: Direct means of measuring down-hole permeability are limited. At the present time, wells are logged during the drilling operation using a variety of logging tools. Several different logs may be used to determine porosity, such as sonic, formation density, and neutron logs. However, permeability can only be estimated from porosity by empirical relationships; these estimates are considered to have only order-of-magnitude accuracy. Permeability can be measured on cores; these are expensive, not always taken at the level of interest, and sometimes fall apart. Flow tests indicate permeability but are time-consuming and expensive.

C. Need/ significance: Next to oil saturation, permeability is one of the key parameters in determining whether a particular geological horizon will be tested for production. The inability to accurately predict formation permeability can result in potential producing zones being incorrectly categorized as uneconomic. Conversely, over optimistic estimates of permeability can result in expensive and fruitless well completion efforts. Moderate significance for exploration.

D. Matching aerospace technology: None identified.

E. Likelihood of solution within 5 years: Unlikely.

F. Evaluation: 1/1,2/2/2/2: Exploration/Any location/Significance not high/No aerospace technology identified/Solution unlikely within 5 years.

(34) Distinguishing oil from water by bore-hole measurements

A.	Problem:	Better technique to distinguish oil from water by bore-hole measurements.
B.	Present technique:	"Electric logs," which measure resistance, or taking samples of the fluid as it flows into the hole. Present electric logs, it is stated, do not always adequately distinguish water in a formation from oil. Sampling gives the composition only at one depth per sample.
C.	Need/ significance:	The composition of the formation fluid must be determined to evaluate the formation. Significance appears low since electrical log usually gives adequate information.
D.	Matching aerospace technology:	Electrical measurements. Possible approaches: a dielectric-constant log; down-hole gravimetry (since oil-bearing strata are generally less dense than water-bearing).
E.	Likelihood of solution within 5 years:	Good likelihood of proving technical feasibility.
F.	Evaluation:	1,2/1,2/2/1/1: Exploration and production /Any location/ Significance not high/Aerospace technology identified/ Solution likely within 5 years.

(35) Improved surface geochemical techniques.

A.	Problem:	Better techniques for detecting subsurface petroleum from surface or above-surface geochemical measurements.
B.	Present technique:	A wide variety of analytical methods have been tried, analyzing for hydrocarbons, other organics, and inorganic indicators in soil, near-surface water, and air. Microbiological indicators have also been tried. Most American companies, it appears, feel that none of these methods is reliable, and they are not generally used by American companies. (Some foreign companies use them.) Levinson (Ref. D-4) believes that the difficulty lies less with the analytical techniques than with inadequate understanding and modelling of fluid transport from subsurface reservoirs to the surface.
C.	Need/ significance:	Surface geological and geophysical techniques do not indicate the presence of petroleum but only of the occurrence of geological conditions or physical properties that may be associated with petroleum. There is therefore much interest in the possibility of surface geochemical techniques that would directly indicate the presence of petroleum at depth. Highly significant.
D.	Matching aerospace technology:	Remote sensing. U.S. Geological Survey is working on satellite detection of petroleum hydrocarbons reaching the surface. These hydrocarbons apparently reduce Fe_2O_3 stains on the rocks, producing a bleaching visible to satellite sensors. Another possible approach is spectroscopic detection from satellites or aircraft of I_2 in the air; the high iodine is presumed to have reached the surface from marine organic deposits that led to petroleum (Refs. D-4, D-5, and D-6). High iodine has been reported in air over and downwind of producing oil fields (Ref. D-7), and more recent work suggests a similar finding over an undrilled prospect subsequently found to contain oil (Ref. D-8). Younger marine sediments overlying possible petroleum reservoirs may interfere.
E.	Likelihood of success within 5 years:	Likelihood of proving technical feasibility of overland detection method fairly good.
F.	Evaluation:	Off shore: 1/1/1/2/2: Exploration/Off shore/High significance/No aerospace technology identified/ Solution unlikely within 5 years. On shore: 1/2/1/1/1: Exploration/On shore/High significance/Aerospace technology identified/Solution likely within 5 years.

(36) Landsat sensors attuned to geologic needs

A.	Problem:	Landsat 1 and 2 images are proving very useful as an aid in reconnaissance exploration for petroleum and mineral resources. Their primary use at present is to serve as an orthophoto map base for compilation of other data and for lineament analysis. The satellite-sensors record reflected light in green, red, and near-infrared parts of the spectrum. These spectral regions were chosen primarily for their usefulness in agricultural work; i.e. crop inventories, crop health, timber studies, etc. and not for geological usefulness. Therefore the spectral information in the images is not optimal for geological purposes.
B.	Present technique:	Use present (agriculturally optimized) Landsat sensors.
C.	Need/ significance:	Moderate. NASA centers are currently analyzing the need for other spectral bands in Landsat-D. Work is in progress specifically addressed to this problem, and recommendations will be made to NASA for additional geologically useful sensors.
D.	Matching aerospace technology:	Remote sensing. Desired sensors can be readily designed and built.
E.	Likelihood of solution within 5 years:	Technical solution available. Utilization depends on institutional/political factors.
F.	Evaluation:	1/2/2/1/1: Exploration/On shore/Significance not high/Aerospace technology available/Solution available (technical).

(37) Better drilling methods

A. Problem: Need faster, more efficient ways to drill; more power at the drill bit. Improvements in present system and/or a new, better, system.

B. Present technique: Rotary drilling via pipe assembly. Bits consist of multiple cutting edges mounted on several disks free to rotate at angle to bit axis. The industry is working on modifications to present drill bits and rigs to increase weight on drill bits, improve bit cutting action, and improve bit life. This is an evolutionary process with no really new concepts being actively investigated. The down-hole motor concept such as the Dynadrill has evolved for use in directional drilling but cannot compare with conventional drill system for straight holes.

C. Need/ significance: Petroleum exploration requires increasingly deeper holes which extend present oilfield technology to the limit. As a result, the drilling costs are rapidly increasing and constraining the amount of exploration. With faster drilling, costs could be lowered, more explanatory wells drilled, and more oil found. A very significant problem.

D. Matching technology: Design for shock, vibration, and other hostile environments; resonant-mechanical mode analysis; thrust-engine design, combustion transients and instabilities; and combustion aerodynamics. Several advanced drilling concepts are being investigated at the ERDA. Some active projects are being conducted:

1. "Subterrene" drilling concept of melting rock by an electrical heated bit.

2. A spark drilling system.

3. An indexing chain drill to allow new cutting surfaces to be moved into place without pulling the drill string from the hole.

4. Replaceable bit cones stored in a magazine above a bit, which can be moved into cutting position without removing the drill string from the hole.

5. A "Terra-Drill" which incorporates projectiles, carried by the drilling fluid, which pass through the center of a conventional bit, penetrating and cracking the rock ahead of the bit for increased drilling rates.

Private companies have proposed:

6. Using acoustic resonance to drive cutting or chipping bits

7. Improved down-hole motors and turbines

Other approaches include:

8. Automated drilling rig to improve efficiency and reduce labor costs

9. Liquid-fueled rocket motor operating in unstable or pulsed mode to drill by high energy chipping blows.

E. Likelihood of solution within 5 years: Moderate probability of proving technical feasibility of 1 or more concepts.

F. Evaluation: 1,2/1,2/1/1/1,2. Exploration and production /Any location/High significance/Aerospace technology identified/Likelihood of solution within 5 years varies.

(38) Drilling stratigraphic test holes

A.	Problem:	Faster and less expensive ways of drilling stratigraphic test holes.
B.	Present techniques:	Small truck- or ship-mounted rotary drilling rigs are usually employed to drill these small diameter, relatively shallow "core" holes.
C.	Need/ significance:	Reduced cost of drilling geophysical test holes would allow increased use of this method; this would provide additional data to help determine where exploratory wells should be drilled. Moderate significance.
D.	Matching aerospace technology:	See Problem 37.
E.	Likelihood of solution within 5 years:	Moderate probability of proving technical feasibility.
F.	Evaluation:	1/1,2/2/1/1-2: Exploration/Any location/Significance not high/Aerospace technology identified/Solution within 5 years uncertain.

(39) Light-weight drilling equipment

A.	Problem:	The high weight of drilling equipment makes it expensive and difficult to move equipment over land.
B.	Present technique:	Rigs and drill pipe are made of moderate-strength steel.
C.	Need/ significance:	Difficult to move drilling equipment to and from remote land locations. High weights make land transport difficult and increase damage to environment by transport vehicles. They also make helicopter transport difficult and expensive. Even in the 48 states, weight limits on roads and bridges limit land transport. Moderately significant.
D.	Matching aerospace technology:	Design, material selection, and fabrication for minimum weight plus ability to withstand severe operating and transport conditions. Testing of equipment performance under severe conditions. Work on the problem is in progress at one aerospace company.
E.	Likelihood of solution within 5 years	High
F.	Evaluation:	1,2/1,2/2/1/1: Exploration and production/Any location/ Not highly significant/Aerospace technology identified/ Solution likely within 5 years.

(40) High-temperature rubber for down-hole drill motors

A.	Problem:	Rubber used for stators of certain positive displacement down-hole drill motors "crumbles" at temperatures above 100°C (210°F): That is, small bits are torn from its surface due to shear failure. The shear forces are produced by metal sliding over the rubber.
B.	Present technique:	Molded rubber.
C.	Need/ significance:	Down-hole drill motors are extensively used to initiate slant and directional drilling and for other special purposes. Some down-hole positive-displacement drill motors use a sleeve-like structure as a stator. This stator acts as a sealing element against a helical screw shaft impeller. The stator must be flexible to follow the helical shaft. If the stator fails, the motor must be withdrawn and repaired.
D.	Matching aerospace technology:	Solid-propellant technology: polymer chemistry; design of composite (reinforced) structures; computer modelling of composite structures. Possible approach: computer-aided design using cord reinforcement and high-temperature rubber.
E.	Likelihood of solution within 5 years:	High.
F.	Evaluation:	2,1/1,2/2/1/1: Production and exploration/Any location/Not highly significant/Aerospace technology identified/ Solution likely within 5 years.

(41) Alternatives to drilling muds

A.	Problem:	Methods of controlling fluid pressure during drilling without muds.
B.	Present technique:	Synthetic "muds" are used to balance fluid pressure, to remove chips, and to provide cooling.
C.	Need/ significance:	Mud gets into pores of formations and plugs them. Mud-plugged formations that are potentially producible may be missed in evaluation; the mud interferes with logging, flow testing, and core testing. If these formations are identified, the mud restricts flow in production or necessitates treatment of the formation. Adds to cost and uncertainty of exploration and production. Significant.
D.	Matching aerospace technology:	None identified.
E.	Likelihood of solution within 5 years:	Poor.
F.	Evaluation:	1,2/1,2/1/2/2: Exploration and production /Any location/ High significance/No aerospace technology identified/ Solution unlikely within 5 years.

(42) Rock implosion into borehole.

A.	Problem:	In drilling and completing wells, sand or rock "implosion" into the borehole is sometimes encountered. Casing perforations are plugged by the sand or rock formation, cutting off oil flow into the well.
B.	Present technique:	The oil industry has developed a number of techniques borrowed from water-well technology to control loose formations. These include screens, gravel packs, cements, and polymers.
C.	Need/ significance:	Reduces oil production. Not an exploration problem.
D.	Matching aerospace technology:	None identified at this time.
E.	Likelihood of solution within 5 years:	Not determined at this time.
F.	Evaluation:	2/1,2/2/2/2: Production/Any location/Significance not high/No aerospace technology identified/Likelihood of solution within 5 years unknown.

(43) Maintaining drill-ship position

A.	Problem:	In some locations and some wind and sea conditions, excessive power is needed to maintain ship position during drilling.
B.	Present techniques:	Drill ships and barges, surface platforms, semi-submersibles.
C.	Need/ significance:	Adds to exploration cost. Not highly significant.
D.	Matching aerospace technology:	None identified. Present petroleum industry techniques plus submerged drilling, being developed by the industry, are applicable.
E.	Likelihood of solution within 5 years:	Fair to good.
F.	Evaluation:	1,2/1/2/2/1-2: Exploration and production/Off shore/ Significance not high/No aerospace technology identified/ Likelihood of solution within 5 years fair to good.

(44) Technical support to independents

A. Problem: Independent oil companies have limited technical support and research assistance. They must rely on consultants and service industry representatives for technical backup. Consultants are usually used only in evaluating individual prospects. The help given by service industry sources may be influenced by personal or proprietary interests. Also, independents have limited capital for engineering work.

Small oil companies sometimes do not have the technical background to specify properly the geophysical measurements they need or to check the quality of the data they have bought.

B. Present technique: Each company must employ staff knowledgeable in critical technical areas, retain consultants or rely on the advice of service contractors.

C. Need/ significance: Independents do the vast majority of on-shore U.S. wildcat drilling. Traditionally, they have discovered large amounts of oil. Improved support services would increase the effectiveness of their efforts. Poor quality geophysical data and interpretation reduce exploration effectiveness and result in less oil discovered. Moderate significance.

D. Matching aerospace technology: Aerospace technology is not especially appropriate. An industry association could be used to prepare survey specifications, share data and monitor quality; it could have its own laboratory and experts to provide technical support to members. Something like the NASA Technology Dissemination Centers might be useful. State supported centers similar to agricultural extension services could be a solution, if politically acceptable. This is done now in France.

E. Likelihood of solution within 5 years: Good.

F. Evaluation: 1/2/2/2/1: Exploration/On shore/Significance not high/No aerospace technology identified/Solution likely within 5 years.

(45) Revised methods of federal leasing

A.	Problem:	Some of the oil companies feel that federal offshore leasing methods cause high costs to them. Some of the smaller companies feel that the methods shut them out, and favor large companies.
B.	Present approach:	Offshore leases are let on the basis of the highest "bonus" (advance payment) offered by the companies in sealed bids. Companies can make geophysical surveys before bidding and, by permission, can drill some stratigraphic test holes, but exploratory wells are drilled only after leasing.
C.	Need/ significance:	Most of the undiscovered petroleum reserves of the U.S.A. are believed to lie off shore. Leasing costs may be many times greater than other exploration costs. The leasing procedure has an important effect on costs and on competitive positions in the industry. It also affects distribution of petroleum revenues between the companies and the federal government. Very significant.
D.	Matching aerospace technology:	A number of alternatives to present methods have been proposed, such as: Royalty bidding; lottery with fixed royalties or rents; federal exploration; etc. No aerospace technology identified.
E.	Likelihood of solution within 5 years:	Solution will be political not technical. Unlikely to occur within 5 years.
F.	Evaluation:	1/1/1/2/2: Exploration/Off shore/High significance/No aerospace technology identified/Solution unlikely within 5 years.

(46) Comparison of drilling experience with predictions

A. Problem: A need exists to correlate geological data with drilling results on a systematic basis. Within some companies, at least, there seems to be a lack of consistent analysis of post-drilling reports to correlate what was discovered with pre-drilling estimates. Details of the final report of unsuccessful drilling programs are sometimes given little attention, and there may be no systematic effort to maximize gained experience. Systematic geological comparisons of successful and unsuccessful prospects are generally limited to what geologists can do without computer assistance.

The lack of a systematic approach to evaluating past results is due to the nonuniform and unique character of each petroleum reservoir. The large number of variables and characteristics makes the application of past experience to a given setting very difficult.

B. Present technique: Each company gains from past experience through the informal transfer of results among its staff.

C. Need/significance: As the search for smaller structures or traps intensifies, the application of improved methods becomes of increased significance. Better comparisons of analogous experience might help eliminate errors in data interpretation and formation evaluation.

D. Matching aerospace technology: Data analysis. The results of NASA supported work by M. D. Mesarovic at Case Western Reserve on multivariable systems may be applicable to this problem. Multivariable systems are a field of systems theory that can be defined as the process of determining coefficients, parameters, and structure of a mathematical model in such a way that it describes a physical process. The method is apparently used by some petroleum companies and some service companies.

Data exist in the files of the oil companies, some in the files of the U.S. Geological Survey. It would be necessary to determine whether data would be made available by them for analysis. Existing image-processing algorithms may be useful in combining data of various kinds.

E. Likelihood of solution within 5 years: Likelihood of proving feasibility of system: good. Likelihood that system will provide useful output: not known.

F. Evaluation: 1/1,2/2/1/2: Exploration/Any location/Significance not high/Aerospace technology identified/Likelihood of solution within 5 years questionable.

(47) Cheaper offshore reconaissance methods

A.	Problem:	Ship operations are slow, costly of capital equipment and running cost, not fast reacting to weather conditions, not conducive to staffing by data interpreters, and because of long turnaround time for data handling and analysis, not operable in an adaptive mode. Wider coverage at lower cost is needed.
B.	Present technique:	Reconnaissance is handled by expeditions mounted with special ships. Missions may involve months of operations. Data are generally brought to shore and then air-shipped to the analysis center. Data analysis occurs too late for refinement of the mission which produced the data.
C.	Need/ significance:	Less cumbersome and better integrated reconnaissance system could reduce exploration costs and perhaps lead to location of more petroleum. Moderate significance.
D.	Matching aerospace technology:	Aviation; remote sensing; data handling; geophysical instruments; communications; large-scale integrated circuits; system engineering. One suggestion (mentioned in Problem number 13) is the establishment of a radio data link between ship and the analysis center. Another possibility is reconnaissance exploration from aircraft. This is already being done for gravity and magnetic measurements; the accuracy of the gravity measurement is poor (see Problem 26); perhaps it can be improved. A possible innovation is reconnaissance seismic exploration from aircraft. This involves a large-scale tradeoff. It would require the development of new hydrophones, data relays, and techniques. The advantages of such a system are 1) Low cost for taking vehicle to station; duty cycle of major capital equipment greatly increased, more cost-effective. 2) Prompt return of data to analysis center without radio data-link. A disadvantage might be the high cost of expendable instruments and data relays.
E.	Likelihood of solution within 5 years:	Radio data-link: technical feasibility established, fair chance of proving economic feasibility within 5 years. Improved accuracy of airborne gravimetry: fair-to-good likelihood. Airborne seismic reconnaissance: Fair likelihood of proving technical feasibility within 5 years.

F. Evaluation:

Radio data link: 1/1/2/1/1: Exploration/off shore/significance not high/aerospace technology identified/ solution likely within 5 years.

More accurate airborne gravimetry: 1/1/2/1/1, 2: as above, except solution less likely.

Airbone seismic reconnaissance: 1/1/2/1/2: as above, solution less likely.

(48) Field detection of source rock

A.	Problem:	Need techniques for use from surface and in field during drilling to determine if a good source rock is present.
B.	Present technique:	Apparently only lab tests of cuttings. Disadvantage is turnaround time of lab test.
C.	Need/ significance:	Adequate technique would permit better estimate of likelihood of finding oil before it is reached by drill. Significant.
D.	Matching aerospace technology:	None identified.
E.	Likelihood of solution within 5 years:	Unlikely.
F.	Evaluation:	1/1,2/2/2/2: Exploration/Any location/Significance not high/No aerospace technology identified/Solution unlikely within 5 years.

(49) Assessment of offshore potential reserves

A.	Problem:	Knowledge of potential offshore reserves is poor, and techniques for estimating these potential reserves are not adequate.
B.	Present technique:	Estimates of sedimentary volume and petroleum content, basin analysis, probabilistic exploration and engineering analysis, and analysis of discovery and production trends.
C.	Need/ significance:	For long-range planning.
D.	Matching aerospace technology:	None identified.
E.	Likelihood of solution within 5 years:	Moderate likelihood of improvement.
F.	Evaluation:	1/1/2/2/2: Exploration/Off shore/Not highly significant/ No aerospace technology identified/Solution unlikely within 5 years.

(50) Extraction of oil from siltstone and other fine-grained reservoirs

A.	Problem:	A large fraction of the oil resources is in fine-grained reservoirs from which it is very difficult or uneconomic to extract the oil.
B.	Present technique:	This problem falls into the well-stimulation area. Present methods include chemical reactions, explosive techniques, and hydraulic fracturing of the reservoir rocks. The oil-well service companies as well as several oil companies have active R&D programs addressing this problem.
C.	Need/ significance:	There is a major need for work on improved well stimulation not only to develop new techniques but to understand and predict the results from present methods. Not an exploration problem.
D.	Matching aerospace technology:	See Problem 52, Better secondary/tertiary recording methods.
E.	Likelihood of solution within 5 years:	Poor. (Present methods have been under development for 20 years or more.)
F.	Evaluation:	2/1,2/1/1/2: Production/Any Location/High significance/ Aerospace technology identified/Solution unlikely within 5 years.

(51) Petroleum production from wells in deep water

A.	Problem:	It is generally not economic to produce oil off shore in water deeper about than 1000 feet.
B.	Present technique:	Ship platforms, semi-submersible platforms
C.	Need/ significance:	There is no reason to think that petroleum deposits are limited to land and to shallow ocean depths (1000 ft). Considerable additional petroleum should be recoverable if techniques were available to produce economically through greater water depths. One difficulty is in getting the petroleum to the surface and to shore cheaply. Not an exploration problem; a very significant production problem.
D.	Matching aerospace technology:	Not aerospace technology. The petroleum industry has technology which needs to be extended. Reliable methods of preventing spills are essential.
E.	Likelihood of solution within 5 years:	Good.
F.	Evaluation:	2/1/1/2/1: Production/Off shore/High significance/No aerospace technology identified/Solution likely within 5 years.

(52) Better secondary/tertiary recovery techniques

A.	Problem:	Only about 30% of the petroleum in a reservoir is produced initially by natural driving forces (gas cap, solution gas, water drive). Since almost 70% of the oil is still remaining in known reservoirs, an economical method of recovering more of this oil would be a major contribution to petroleum production.
B.	Present techniques:	A number of methods have been tried with varying degrees of success for recovering the petroleum remaining in the reservoir after initial production has ceased. These include water-flood techniques using different chemical additives, thermal recovery techniques, involving steam injection and *in situ* combustion, and solvent recovery methods. In all of these methods, the surface equipment involves large expenditures, and economic success depends upon the knowledge of reservoir conditions and proper application of the recovery techniques to match these conditions.
C.	Need/ significance:	Highly significant production problem; not an exploration problem.
D.	Matching aerospace technology:	One area to which aerospace technology might be applied is *in situ* combustion. A second area of expertise is thermal modelling which might prove to be useful in understanding the recovery mechanisms. A third area involves polymer chemistry to provide additives to reduce viscosity and surface tension of the petroleum, as well as methods of controlling the flow of the recovery fluids. ERDA has a program underway in cooperation with several oil companies to investigate tertiary recovery methods.
E.	Likelihood of solution within 5 years:	Partial success could be expected.
F.	Evaluation:	2/1,2/1/1/1: Production/Any location/Highly significance/Aerospace technology identified/Solution likely (partial) within 5 years.

(53) Perforating casing and deep into formation

A.	Problem:	Present perforation methods are limited to a few inches depth of penetration into the formation. It would be beneficial to increased production to penetrate the formation several feet.
B.	Present technique:	Casing performation is currently accomplished by use of multiple shaped charges and apparently the results are usually but not always satisfactory.
C.	Need/ significance:	Not an exploration problem.
D.	Matching aerospace technology:	Possibly a laser technique could produce deeper and more controlled penetration than the explosive methods. It is also possible that combustion research might produce methods of deeper penetrations.
E.	Likelihood of solution within 5 years:	Poor. The oil industry has had active research programs for years; an order-of-magnitude improvement will be hard to develop.
F.	Evaluation:	2/1,2/2/1/2: Production/Any location/Significance undetermined/Aerospace technology identified/Solution unlikely within 5 years.

(54) Material resistant to hydrogen sulfide

A.	Problem:	H_2S (hydrogen sulfide) gas corrodes casings and valves. Needed is material which has the strength of steel, but is nonreactive with H_2S.
B.	Present technique:	H_2S resistant material is generally used.
C.	Need/ significance:	H_2S gas has always been a problem in the oil industry. Methods, materials and techniques have been developed to cope with the problem. It is not clear that development of new materials is economically justified. Not an exploration problem.
D.	Matching aerospace technology:	Technology needed is not particularly that of aerospace.
E.	Likelihood of solution within 5 years:	Good technically but poor economically.
F.	Evaluation:	2/1,2/2/2/2: Production/Any location/Significance questionable/No aerospace technology/Solution unlikely within 5 years (economic).

(55) Steel quality control

A.	Problem:	Quality control of new and used tubular goods and accessory steel parts leaves much to be desired.
B.	Present technique:	Several inspection techniques are currently used and are fairly successful and economical. The problem seems to be that the steel mills are not producing as high a quality as possible because of the large increase in orders. This problem should gradually disappear as the backlog of orders is filled.
C.	Need/ significance:	As wells are drilled and produced at greater depths, the quality of the tubular goods will be more and more important in preventing failures. Primarily a development and production problem rather than an exploration problem.
D.	Matching aerospace technology:	Some aerospace quality control and inspection techniques may be applicable.
E.	Likelihood of solution within 5 years:	Good.
F.	Evaluation:	2/1,2/2/1/1: Production/Any location/Significance moderate/Aerospace technology identified/Solution likely within 5 years.

(56) Sea-ice prediction

A.	Problem:	Measurement and prediction of sea ice location, thickness, strength, and pressure. Tracking and prediction of iceberg position.
B.	Present technique:	Location from ship, aircraft, shore stations. Thickness from ships. Strength occasionally from ships. Pressure sometimes estimated from wind speed and drag coefficient of upper surfaces of floes, if these are known.
C.	Need/ significance:	For operation of survey ships in arctic waters; for exploratory drilling in arctic waters. Since the exploration can be seasonal, problem is greater for production: drilling, operation of platforms and ships, supply. Exploration significance: solution would reduce exploration costs, increase chance of finding oil. Moderate significance in exploration.
D.	Matching aerospace technology:	Aircraft and satellite imaging, imaging radar, radiometry. Location can be determined by imaging and by imaging radar. Providing satellite observations with adequate resolution, area coverage and frequency may be a problem. Microwave radiometry can distinguish first-year ice from multi-year ice and so provide an identification of thickness and strength. Resolution of microwave radiometry is adequate from aircraft; inadequate from satellites to resolve individual floes and leads at the present state-of-the-art. Measurement of the height of floe upper surface above the sea may be possible by radar; this would also give an indication of thickness and possible strength. An experiment is in progress on tracking of floe motion via radio beacons dropped from the air and communicating via satellite.
E.	Probability of solution within 5 years:	Technical feasibility already exists for location from aircraft and satellites; highly likely within 5 years for thickness from aircraft; fair for thickness from satellites.
F.	Evaluation:	2,1/1/2/1/1: Production and exploration/Off shore/ Significance not high for exploration/Aerospace technology identified/Solution likely within 5 years.

(57) Iceberg control

A.	Problem:	Diversion or destruction of approaching icebergs that threaten a drilling rig or production platform.
B.	Present technique:	Floating rig is disconnected from hole, moved to safety, then moved back and reconnected.
C.	Need/ significance:	For exploratory and development drilling and for production in arctic waters. Interruption by present technique is costly. Probably more significant for development and production than for exploration. Moderate significance in exploration.
D.	Matching aerospace technology:	None identified that appears promising.
E.	Probability of solution within 5 years:	Fairly good, using tugs to divert iceberg.
F.	Evaluation:	2,1/1/2/2/1: Production and exploration/Off shore/ Significance not high for exploration/No aerospace technology identified/Solution likely within 5 years.

(58) Earthquake prediction

A.	Problem:	Prediction of location and magnitude of earthquake expected ground motion.
B.	Present technique:	None operational in U.S.A.
C.	Need/ significance:	To help in location and design of offshore platforms. Pertains primarily to petroleum production. Moderately significant.
D.	Matching aerospace technology:	Radio astronomy; data analysis and processing. Consider able international effort underway. Present approaches: measurements of crustal strain, electrical and magnetic monitoring of changes in ground electrical resistance, monitoring of changes in seismic wave velocities. In the U.S., major efforts involve the U.S.G.S. and various university centers. A NASA laboratory is studying some aspects of the problem, applying, where possible, space-related techniques.
E.	Likelihood of success within 5 years:	Likelihood of proving technique good.
F.	Evaluation:	2/1/2/1/2: Production/Off shore/Significance not high/Aerospace technology identified/Solution unlikely within 5 years.

(59) Time-scale for replacement of petroleum by other energy sources

A.	Problem:	Petroleum is becoming increasingly difficult to find in the U.S. It is government policy to reduce dependence on imported petroleum. Moreover, foreign petroleum resources will also decrease. It is clear that eventually petroleum must be replaced by other energy resources. The time-scale over which this is likely to occur is not very clear, however.
B.	Present technique:	Estimates of resources, reserves, and discovery rates. Trend extrapolation. Estimates of times for technical and economic development of possible replacements.
C.	Need/ significance:	Better estimates of the time-scale would help in long-range planning.
D.	Matching aerospace technology:	Data analysis, systems analysis.
E.	Likelihood of solution within 5 years:	Progress likely.
F.	Evaluation:	2/1,2/2/1/1: Not exploration/Any location/Significance not high/Aerospace technology identified/Solution likely within 5 years.

References to Appendix D

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APPENDIX E

ELEMENTARY EXAMPLE OF THE SYSTEMS APPROACH TO SEISMIC-REFLECTION PROSPECTING

The concepts of system analysis and system engineering have been successfully applied to aerospace projects. Since these concepts saw the peak of their development and use in the aerospace field, they are considered derivatives of aerospace technology.

System analysis is a discipline which models a system by describing the interrelationships among its various hardware and software elements. Trade-off studies are an important part of this discipline. System engineering is the conception, design, development, and operation of relatively large complex systems. It is concerned with creating an optimum system to perform a specific function within a set of specific constraints, the most important of which are usually performance, time, cost, and manpower. It is this concept of system engineering which is most familiar in the aerospace field.

The term "system" encompasses an operating system whose input is the performance requirements and whose output is the actual performance (including reliability). An operating system is composed of the following elements: hardware, operating procedures (including software), personnel (and their training), environment, support equipment and logistics, and financial resources (cost). All these elements must work together for the overall objective of the system.

Although the systems approach has usually been applied to new projects (systems having new objectives), many of its aspects have also been found useful in attempts to improve existing systems. The systems approach offers an orderly step-by-step process by which requirements are first analyzed on the system level; implementation alternatives are next explored (also on the system level); subsystems are then defined, and requirements and implementation alternatives can then be explored on the subsystem level. This methodology is superior to a "troubleshooting" approach where efforts are directed at selected problem areas on the element or component level and then "fixing" such problems.

A requirements analysis, which must be performed on the system level before it can be performed on a subsystem level, addresses the questions which are posed below for the case of a system; later, they can be applied to subsystems merely by replacing the word "system" by "subsystem":

1) What does the system have to do? (The objective, in terms of functional requirements.)

2) How well does it have to do it? (The objective, in terms of performance requirements.)

3) What are the allowable or necessary interactions of the system with other systems? (Interface requirements.)

The first two questions need no further clarification. The third question becomes clearer when we consider that "other systems" can include such diverse "systems" as the natural environment, the news media, other seismic exploration systems (e.g., used by competing companies at the same time in the same area), other petroleum exploration systems, and management (e.g., decision-making) systems.

The analyis of implementation alternatives, again done first on the system level and later on the subsystem level, addresses the question: What sort of system will best meet the specified requirements?

When we attempted an elementary application of the system approach to seismic-prospecting systems, it became immediately apparent that the levying of performance requirements, particularly at the system level, would be extremely difficult. In some cases, nothing better than "to be determined" could be provided. In other cases, a brief discussion was supplied in lieu of "hard" numerical performance requirements. It is quite possible that future work could result in a better set of performance requirements.

The following, then, is an example of a set of requirements for a seismic-prospecting system, based on the systems approach. It should be noted that implementation alternatives on the system level were not addressed (what other type of seismic-prospecting system could meet the overall system requirements?); instead, a system of the currently used type was assumed to have been selected. Also, interface requirements were not included on either the system or subsystem level.

I. SYSTEM OBJECTIVE

The objective of the seismic-prospecting system shall be to improve the probability of accurately locating energy-producing fluids below the surface of the earth.

II. OVERALL SYSTEM REQUIREMENTS

The overall system requirements shall include:

1) Functional Requirement. The seismic-prospecting system shall provide geological information regarding subsurface structure by interacting with a geological formation.

2) Performance Requirement. The seismic-prospecting system shall be capable of improving the ratio of potentially producing wells to dry holes by at least a factor of (to be determined) over that ratio obtained without the use of the system.

III. OVERALL SYSTEM DESCRIPTION

The seismic-prospecting system (see Figures E-1 and E-2) shall comprise elements required for the following major functions:

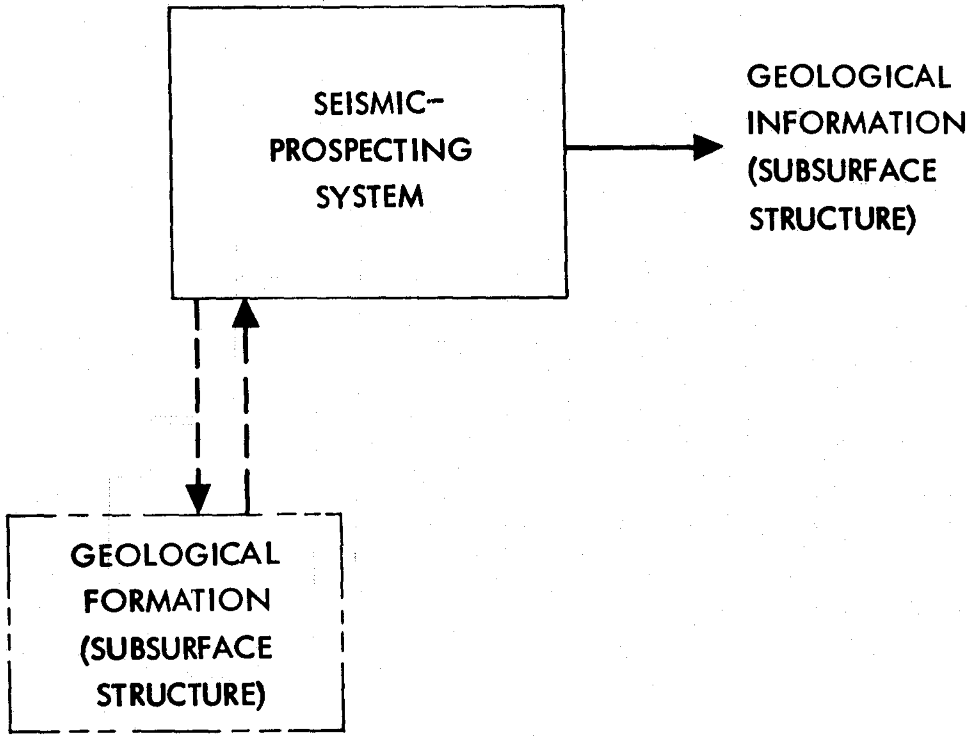


Figure E-1. Overall Functional Definition

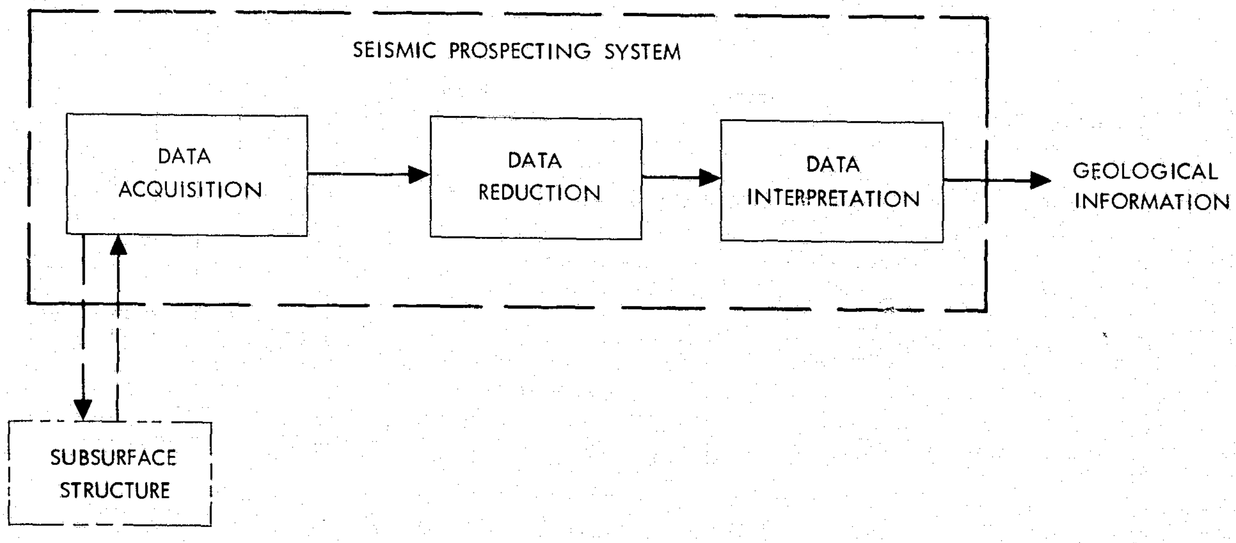


Figure E-2. Simplified System Diagram

1) Data acquisition.

2) Data reduction.

3) Data interpretation.

IV. SYSTEM FUNCTIONAL DESCRIPTION

The seismic-prospecting system (as defined for this report) is shown in Figure E-3. It consists of those hardware and software elements required for the generation of a stimulus into the subsurface structure, the transduction of resulting reflected waves, the conditioning (which usually includes digitization) of transducer output signals, time-tagging of data, data storage, transfer of data to the site at which the data reduction elements are located, the reproduction, processing, and display of data, and the interpretation of data which results in the required geological information about the subsurface structure.

V. SUBSYSTEM DEFINITION

The seismic-prospecting system shall consist of the hardware and software subsystems listed below. Additionally, the system shall comprise operational procedures, training procedures, accounting and management procedures, support equipment, logistics, and personnel:

1) Stimulus generation subsystem.

2) Reflected-wave transduction subsystem.

3) Signal-processing hardware subsystem.

4) Signal-processing software subsystem.

5) Data storage subsystem.

6) Data transmission subsystem.

7) Data-processing and display hardware subsystem.

8) Data-processing and display software subsystem.

9) (If radio telemetry is used) Data reception and demodulation subsystem.

The subsystems and their functional interrelation are shown in the block diagram, Figure E-4.

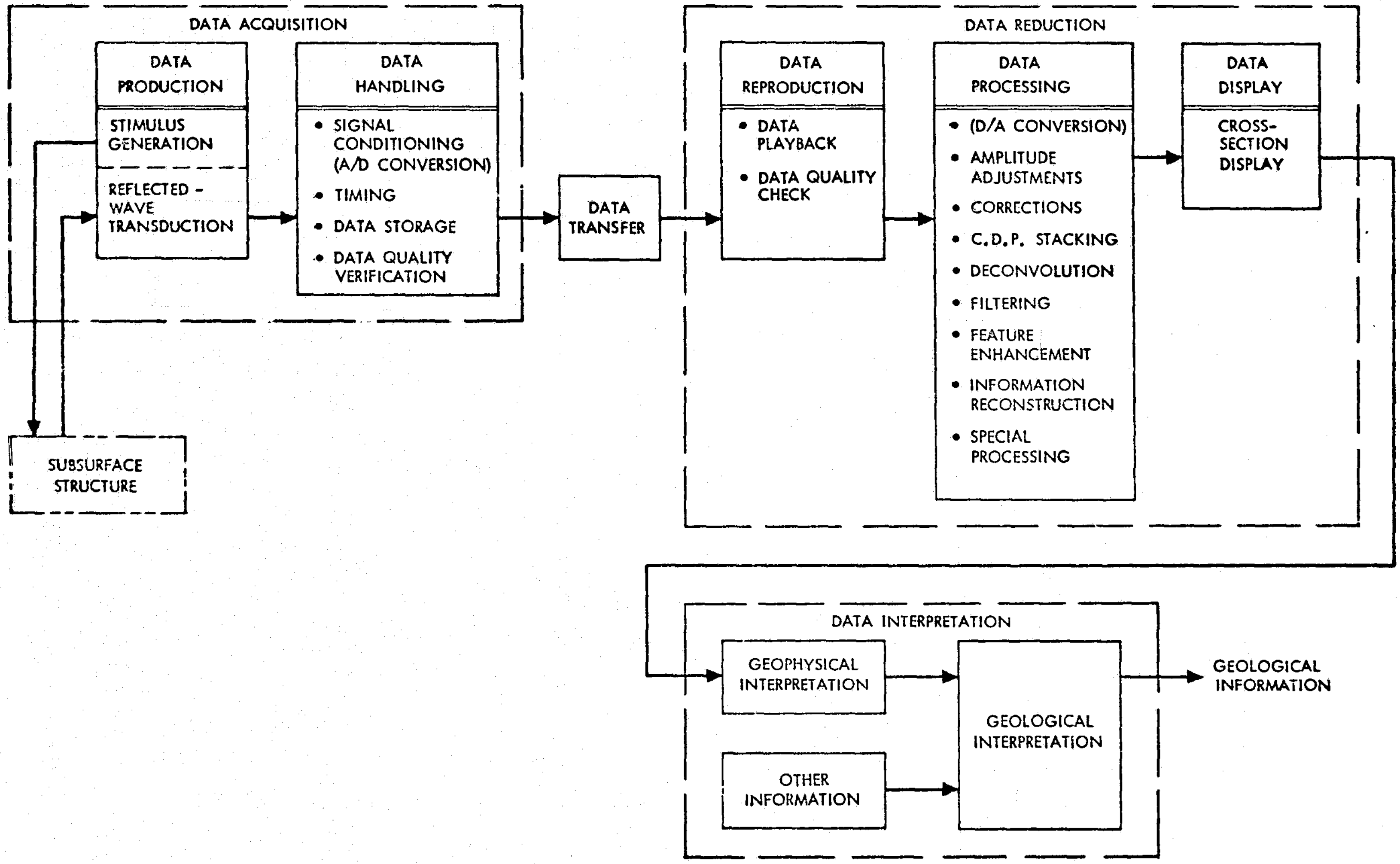
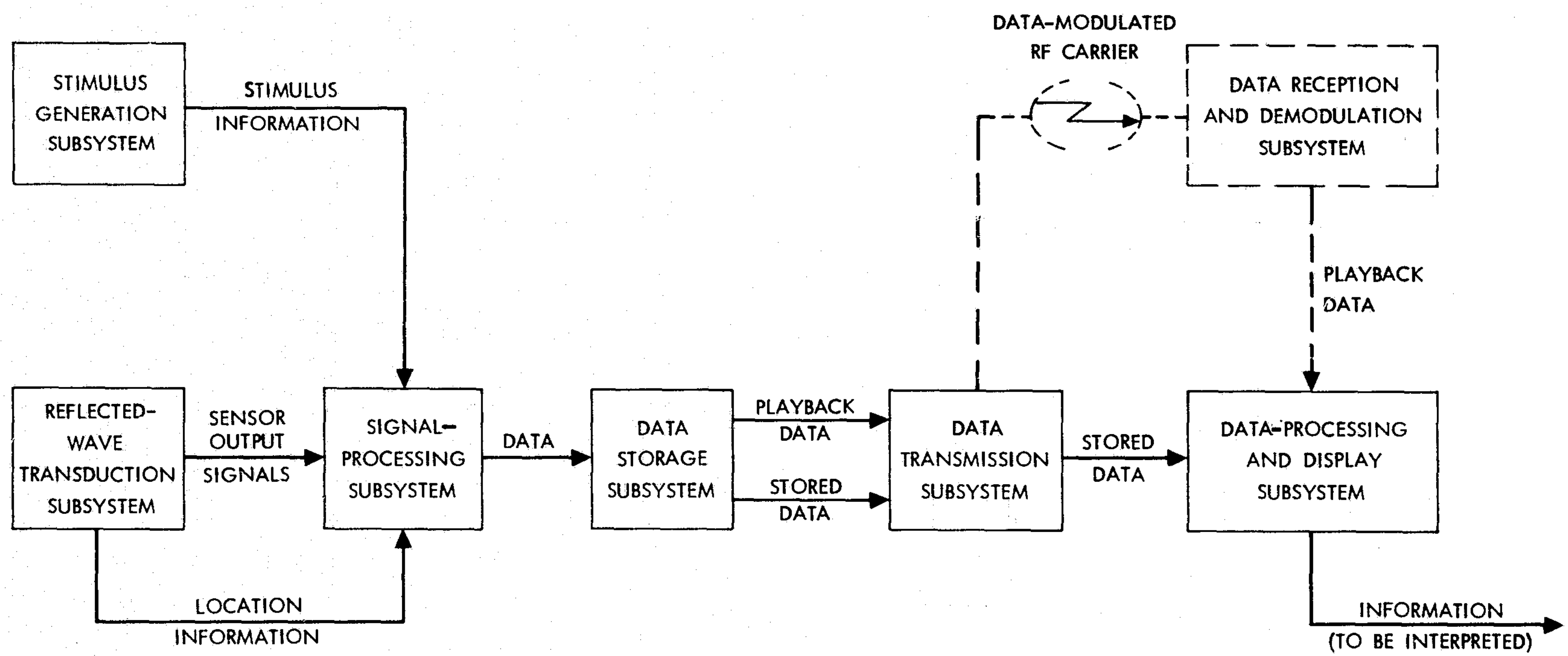


Figure E-3. Seismic Prospecting System Functional Flow Diagram



NOTE: DOTTED LINES INDICATE RADIO TELEMETRY ALTERNATIVE

Figure E-4. Seismic Prospecting System Block Diagram

VI. SUBSYSTEM REQUIREMENTS

A. STIMULUS GENERATION SUBSYSTEM

The stimulus generation subsystem will provide

1) One or more sound-pressure pulses of known energy and wave-shape characteristics.

2) Means for controlling, activating and sequencing the sound-pressure pulses.

3) Means for placing the sound-pressure pulse sources at known locations.

4) Information about location and characteristics of the sound-pressure pulse sources.

B. REFLECTED-WAVE TRANSDUCTION SUBSYSTEM

The reflected-wave transduction subsystem will provide

1) A specified number of transducers of the same type and with known performance characteristics which are capable of producing an electrical output signal in response to sound-pressure waves reflected by subsurface strata upon incidence of sound-pressure pulses supplied by the stimulus generation subsystem.

2) Means for connecting specified numbers of transducers into groups so that the combined source impedance of each group is known.

3) Means for interconnecting groups of transducers, at known locations, with the signal-processing subsystem.

4) Information about transducer type, grouping and location.

C. SIGNAL-PROCESSING HARDWARE SUBSYSTEM

The signal-processing hardware subsystem will provide the hardware required to

1) Check transducer-group output signals.

2) Amplify the incoming signals.

3) Modify the frequency characteristics of the signals.

4) Convert the signals into digital form.

5) Generate timing signals.

6) Identify signals.

7) Supply any required data compression.

8) Accept locational and characterizing information from the stimulus generation and reflected-wave transduction subsystems as well as any additional required operational information.

9) Multiplex and format all data into a single serial bit stream.

10) Verify the quality of the data in the bit stream.

D. SIGNAL-PROCESSING SOFTWARE SUBSYSTEM

The signal-processing software subsystem will control and sequence all programmable portions of the signal-processing subsystem.

E. DATA STORAGE SUBSYSTEM

The data storage subsystem will

1) Accept the data stream from the signal-processing subsystem.

2) Provide for bulk storage of the data.

3) Provide for identification of the data contents of magnetic tapes (or other removable bulk-storage devices).

4) Provide for playback of the data at a specified data rate.

F. DATA TRANSMISSION SUBSYSTEM

The data transmission subsystem will

1) For the stored-data-transfer alternative:

   a) Provide means for an effective transfer of stored data from the data acquisition area to the data processing and display subsystem.

   b) Provide the required control and knowledge of the data transfer function.

2) For the playback-data-transfer (radio-telemetry) alternative:

   a) Control the playback of stored data at the required time.

   b) Provide any required error-correction coding of playback data.

   c) Generate an RF carrier and any required subcarrier.

d) Provide for modulation of the subcarrier and/or carrier with the playback data.

e) Radiate the modulated RF carrier to the data reception and demodulation subsystem.

G. DATA RECEPTION AND DEMODULATION SUBSYSTEM*

The data reception and demodulation subsystem will

1) Receive the modulated RF carrier from the data transmission subsystem.

2) Demodulate the carrier so as to reconstitute the digital data stream.

3) If error-correction coding was employed before data transmission, decode the data and provide information about error-correction observed.

4) Forward the data to the data-processing and display subsystem (which may or may not be co-located).

5) Provide information about received-data quality and the status of its own equipment.

H. DATA-PROCESSING AND DISPLAY HARDWARE SUBSYSTEM

The data-processing and display hardware subsystem will provide the hardware to:

1) Playback stored data and furnish data quality information about the as-received data (for the stored-data-transfer-alternative only).

2) Accept the data stream from the data reception and demodulation subsystem (for the radio-telemetry alternative only).

3) Perform all required data-processing functions directed at optimizing the reconstruction of information and facilitate its interpretation.

4) Display the processed data in the form required for interpretation.

I. DATA-PROCESSING AND DISPLAY SOFTWARE SUBSYSTEM

The data-processing and display software subsystem will control and sequence all programmable elements of the data processing and display hardware subsystem.

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*For radio-telemetry alternative only.

J. DETAILED SUBSYSTEM DESIGN, FUNCTIONAL AND PERFORMANCE REQUIREMENTS

These requirements cannot be generated until subsystem elements have been selected for a more specifically delineated system objective (e.g., a seismic survey in a specific terrain over at least a partially understood geological formation). This, then, permits the preparation of detail subsystem requirements. These will include, for each subsystem, a block diagram showing all elements of the subsystem and their interfaces, all external interfaces of the subsystem (electrical, environmental, mechanical, etc.), and all applicable constraints and or performance requirements.

Performance requirements can specify the energy level and wave-shape characteristics of the stimulus, transducer characteristics (including those which tend to minimize the effects of surface waves, mode-converted waves, ambient noise and instrumentation noise), wear and abrasion characteristics of cables, specific signal-processing hardware and software, data storage fidelity characteristics and operating life, specific data-processing hardware and software (e.g., for corrections, amplitude adjustments, deconvolution, common-depth-point stacking, filtering, and feature enhancement) and other required characteristics.

Furthermore, once subsystem detail requirements are established and documented, a managerial system of change control can be maintained by which only those changes which have been reviewed for their effect on the overall system can be made and which will be documented so that appropriate personnel remains informed. Also, the process of establishing detail subsystem requirements, as long it is reviewed and controlled by "systems people", offers a cost-effective manner of assessing proposed performance improvements (or cost reductions).

APPENDIX F

DETAILS OF AERIAL SEISMIC SYSTEM

I. REQUIREMENTS

The system will be capable of landing and retrieving portions of a seismic survey system sufficient to obtain adequate seismic data for a geologist to make a preliminary determination of the underlying strata and structure. Other portions of the system may be retained on the aircraft. Each landed data package will contain the necessary electronics plus twelve groups of geophones, each group consisting of perhaps ten geophones. Their outputs are summed and sampled as one unit. Each channel (group) will have response up to 100 Hz, requiring a sample rate of 200 per second. A low-pass filter should be placed in front of the digitizer to prevent foldover. The industry standard of 3 (or 4) gain bits plus 15 digitizer bits can be maintained for processing compatibility although such resolution is unnecessary.

The channels will be sampled for 6-10 seconds after each source firing. Data rate will be 12 channels x 200 samples per second x 18 bits per sample = 48000 bps for 6-10 seconds. Data buffering can be used to reduce this peak rate if the firing interval can be extended. Two minutes between firings reduces the required data rate by a factor of 20.

II. DESCRIPTION

Aerial seismic surveys would be conducted by an airplane that drops the geophones, with portions of the data system, and a seismic source. The source would probably be either a shaped charge of explosive or a small packet of specially designed solid-rocket propellant. Each landed data package would include a telemetry set to transmit data to recorders that would be carried in the plane. Each data package and, perhaps, each source package would have a built-in means of recovery.

The plane would be a modified HC-130 that has proven many of the concepts incorporated in this report or a less expensive plane suitably modified. The HC-130 payload capability of 25,000 lbs provides the ability to carry an estimated 250 units. Volume limitations would probably reduce this number to somewhere near 50. Both drop and recovery techniques have been developed to a high state, and the knowledge can be readily transmitted to civilian aircrews. The plane's recovery capability which has been tested in land, sea, and air pickups is 500 lbs. This is well above the estimated weight of the landed data package.

The landed equipment would be separated into two kinds of packages: data packages and source packages. Each data package would contain a multiplexer, digitizer and telemetry encoder, and transmitter. The source package would contain an explosive charge, shaped for maximum effectiveness, or a small packet of rocket fuel, and a command receiver to ignite it when the crew is ready to take data. Penetrators that are designed to put the charge some depth into the soil can be used if desired. Recovery equipment consisting of a balloon, inflating mechanism, cable and drum, along with a radio receiver, would be a part of each package to be recovered.

C,2

Extraction of the packages from the plane would be by parachute which would stabilize the equipment during descent as well as pulling it out of the plane and provide an acceptably slow rate of descent. The landing shock would be absorbed by crushable blocks on the bottom of each package.

The geophones would be attached to the data package with a steel cable as well as with an electrical cable. These cables would be folded against the data package accordian style while in the aircraft with the end and each loop attached to the plane floor with a breakable link. As the package leaves the plane and tension builds in the cable, the links would break consecutively thus stretching the cable to its full length. Aerodynamic shapes could be built around each geophone to assure proper orientation at landing. These shapes and the drop height would be adjusted to keep the cable fully deployed on landing. Spikes attached to each geophone would stick in soft ground thus providing proper coupling, and flat plates would be provided for hard ground. To avoid obtaining signals from nonvertical geophones (those that may have tipped over because of hitting rocks), a switch could be incorporated to permit signals only from properly aligned geophones to be incorporated in the data stream. Alternatively, gimballed geophones could be used.

On the first pass over a given area, the plane would drop data packages. Several passes might be required to lay out the entire grid. After the data packages land, source packages would be dropped. When the airborne recording equipment and operators are ready, the source would be ignited by command from the plane. More than one source might be used to obtain a more detailed picture of the subsurface structure. Geophone output would be multiplexed and digitized by the landed equipment. The digital data stream would be telemetered to the plane where it would be displayed on a multichannel oscillograph and recorded on magnetic tape. Equipment that is now industry standard may require some repackaging, although newer equipment that incorporates telemetry may be suitable.

A frequency in the 130-MHz band would be used through a simple whip antenna on the data package and a blade on the aircraft. A simple FSK transmitter could be used, and since the range to the plane would probably not exceed 10 miles, and be in line-of-sight, a low-power transmitter of about 10 watts would be adequate. The plane would be far enough away during recording that its noise does not affect the geophone signals.

Each landed data package would include retrieval equipment which would consist of an inflatable balloon attached to a cable rolled on a drum. At a command from the plane, the balloon would inflate and rise, unrolling the cable as it does so. The lower end of the cable would be securely attached to the package. The plane would then fly into the cable securing it in the hook assembly built into its nose. As the plane flew along, the package, with geophones trailing, would be picked up and would follow an arc to a position behind and slightly below the plane. The crew would lower a grapple from the tailgate of the plane, securing the lift cable, and would draw the package and geophone string into the plane. The command receivers used with the source packages could either be expendable, or as with the data packages, be equipped with retrieval hardware. If retrievable, they would be designed to separate sufficiently from the sources at landing so that they are not damaged by the sources.

A stereo camera would be used to photograph the geophone layout. These pictures would be used in data reduction to show the orientation of the geophones and their position and elevation relative to the source and to the ground and in relation to geology of the area.

The plane might have some limited processing capability but probably would have nothing beyond the oscillograph. It would fly the data tapes to a location as near as possible to a processing center and would transfer them to another transportation system for further shipment. Analysis would be done at the processing center as it is now.

Navigation is an important point. The plane would have to have an inertial navigation system probably supplemented with a multibeam doppler radar system.

An aerial survey need not be conducted solely from the air but may be a combined air-ground operation. Two approaches are possible in this mode; telemetry reception and recording on the plane and mere pickup of recorded tapes. The second approach falls under aerial resupply of ground parties rather than aerial surveying and will not be considered. The approach of having the plane record the data as the ground crew fires the source and moves the geophone strings gives the advantage of high resolution without undue time to place and retrieve the packages and rapid return of data to the processing center. The problems involved in coordinating the efforts of the plane and ground crews may outweigh this advantage, however.

The techniques of air drop and recovery described here requires the use of a fixed-wing aircraft. If one is willing and able to deploy a crew on the ground to set up and recover the equipment, a large helicopter could be used to supply them with the equipment and transport the crew to and from the site. This alternative has been used to some extent.

The time involved in deploying the packages and in retrieving them prevents the aerial technique from performing a high-resolution mapping of a large area. It is technically feasible, however, to obtain a low-resolution map of a limited area by this technique.

III. PERFORMANCE ANALYSIS

Detailed mapping of areas, while technically feasible, is likely to be impractical in most areas. The system may be useful in remote areas or those where ground crews have difficulty operating or are likely to damage the environment impermissibly. Arctic, swamps, and desert areas may be examples. Precautions will have to be taken in arctic operation to minimize the probability of creating an ice fog and making further operation impossible. The technique would not be practical in areas with heavy tall foliage.

The technology for this system is developed and in use. The feasibility of demonstrating it within 5 years is very good.

The purchase price of the airplane, modified as required, will be on the order of $8,000,000 if a new C-130 is purchased. All but about $500,000 is airplane; this could be greatly reduced if an older plane was purchased and modified. A suitable used plane could be obtained for less than $500,000.

The direct operating costs of flying the plane would be about $900 per hour.

One further point needs to be made. The airborne recovery system known as the Foster System is no longer in production, and the tooling has probably been scrapped. The price estimates above assume that it will be possible to obtain at least one complete unit from supplies obtained by the Air Force when they converted some of the HC-130s to C-130s by removing the pickup equipment. The cost of repackaging the seismic equipment will be a small fraction of the remaining cost, probably less than 10 percent.

IV. SUMMARY

A technique for conducting aerial seismic surveys has been presented. The technique is technically feasible; the methods are developed, but some modifications to equipment currently in use by the industry would be required. Repackaging of equipment would have to be accomplished, and parachute and landing pallets as well as portions of the recovery system would have to be designed.

This technique appears to be most suited to obtain a low-resolution map of a limited land area to determine whether the site appears to be promising enough to send in a ground crew for a detailed survey.

APPENDIX G

DETAILS OF TELEMETERING SEISMIC DATA TO ANALYSIS CENTER

Companies interested in seismic surveys gave the following ranges of values for system parameters:

Parameter	Values: Minimum	Values: Maximum
Number of channels	12	96
Sample rate, samples/channel/sec	250	1000
Digitization, bits per sample	16	32

Overall peak data rates vary from 96 kbps to 1.6 Mbps per ship or land survey team. Marine survey rates normally are in the 0.4-1.6 Mbps range. One user predicts data-acquisition rates for marine surveys will reach 10 Mbps per ship by 1985.

Firings for marine surveys occur at 6- to 12-second intervals with data accumulation periods of 6 seconds per firing. Land surveys may have firings spread as far as 30 minutes apart with data-accumulation periods of 10-30 seconds. Land surveys are amenable to data storage at peak-data rates with subsequent playback at reduced data rates. Both land and marine surveys are often performed 24 hours per day.

The number of seismic exploration ships operated by U.S. companies is in the 50 - 75 range. There are several hundred land survey crews.

Primary interest (for this study) is in providing communications on or near the North American continent.

I. MARISAT

Marisat is a two-ocean geosynchronous satellite system developed to provide communications services for the U.S. Navy and for commercial shipping. The coverage area for Marisat is shown in Figure G-1. Principal ownership of Marisat is by Comsat General. The Atlantic satellite is operational, and the Pacific satellite will be operational for commercial use this year.

The basic system uses shipboard terminals with a 4-foot diameter parabolic antenna, 30-watt transmitter, and G/T of -4 dB/K. Cost of the shipboard terminals are $52,000 without installation, which is considered a minor cost. Terminals may be leased for $1225 per month which includes maintenance. Communication between ship and the satellite is at L-Band (1.5 and 1.6 GHz). Communication from satellite to shore is at C-Band (4 and 6 GHz). Initially, one Comsat General earth station will be used with each satellite.

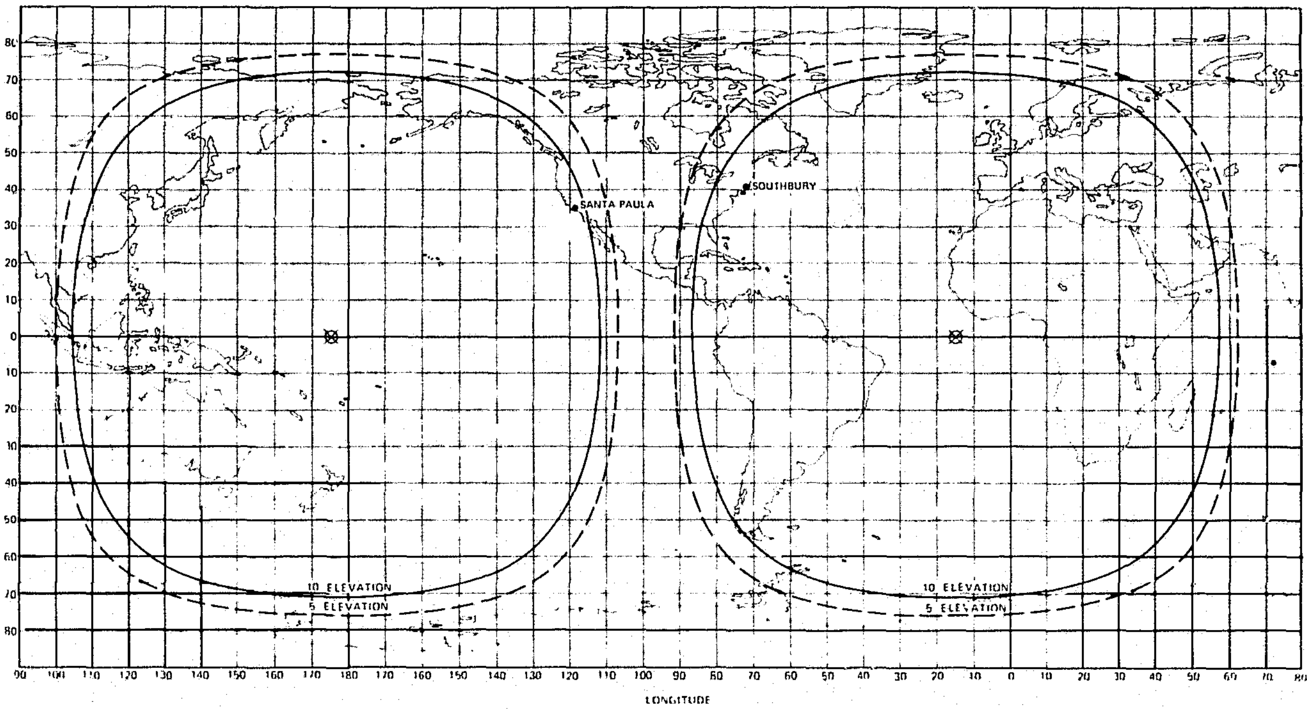


Figure G-1. Marisat Coverage Plots

A Santa Paula, California, station serves the Pacific satellite, and a Southbury, Connecticut, station serves the Atlantic satellite. Common-carrier facilities provide connection from these ground stations to the destination in the continental United States.

Basic commercial service capabilities and costs are shown in Table G-1. These capabilities assume that the satellite is not providing service to the Navy. A single ship has the capability of simultaneously transmitting one voice channel plus one teletype channel.

Table G-1. Marisat Standard Service Types and Cost

Service Type	Number of Channels Available	Cost for Channel Use, $/Min.
Voice or up to 2.4 kbps data	14	10
Teletype (50 baud)	44	4 ($6/min if less than 200 min/month used)

Comsat General is developing modified shipboard terminals which will provide two ship-to-shore channels at 240 kbps through each satellite. These terminals wil be similar to the standard terminals but have a larger transmitter (estimate 2 kW) and will cost $80,000 to $100,000 each. Use of one 240-kbps channel from ship to data analysis center in Houston or Dallas will run $300-500/hour on short-term usage basis. If the total channel were permanently leased, the cost would be considerably less.

To summarize, Marisat currently can provide voice or data (to 2.4 kbps) from its coverage areas (Figure G-1) to data analysis centers on the continental U.S. Planned future capability will provide two channels/ocean of 240-kbps capability.

Comsat General has sold a number of Marisat ship terminals to oil companies; these are or will be installed on mobile drilling ships, barges, and seismic exploration ships. They are working with the American Petroleum Institute in planning current and future oil industry communications satellite support, including a future satellite system which will support megabit data rates.

II. ADVANCED MOBILE SATELLITES

A. GENERAL

The maritime mobile-satellite spectrum allocation is as follows:

Routing	Assigned Band	Bandwidth
Mobile-to-Satellite	1636.5-1644 MHz	7.5 MHz
Satellite-to-Mobile	1535-1542.5	7.5 MHz

This bandwidth will support approximately 7.5 Mbps using PSK modulation or 15 Mbps using QPSK modulation. To consider a large number of ships operating at 10 Mbps/ship would require a multibeam satellite with one ship operating per beam or one satellite supporting one ship (which is economically unrealistic).

To provide 10 Mbps service to a large number of ships, the best alternative would probably be to secure a larger bandwidth allocation for maritime mobile-satellite.

Developing formal satellite system requirements and appropriate system configuration for support of oil companies would require extensive interface work with the companies, trading off potential requirements with satellite system alternatives. There is currently no land mobile-satellite frequency allocation. An allocation would have to be secured in order to provide land mobile service.

B. POTENTIAL CONFIGURATION

A potential system configuration has been developed which will support continuous transmission at 400 kbps (ship-to-shore) for 32 ships. The system uses two satellites, one in the Atlantic and one in the Pacific with coverage of essentially the northern hemisphere portion of the coverage shown in Figure G-1. Moving the Atlantic satellite slightly west would provide coverage of the Carribean.

Shipboard terminals are the same as the enhanced Marisat terminals discussed above. These terminals use 4-foot antennas and 2-kW transmitters. Cost is assumed to be $100,000 per terminal with lease of $3,000 per month.

Satellite characteristics are

L-Band Antenna:	Boresight gain = 23.6 dB
	Beamwidth (3 dB) = 11 degrees
L-Band Receiver Temp.:	850 K
G/T (L-Band):	- 8.7 dB/K

Only the ship-to-satellite link was considered since it is the most critical. The C-Band satellite-to-shore link will require a larger antenna than that used on Marisat. This is not a major problem.

The basic concept is to provide four 1.6-megabit/second links through each satellite either using separate transponders or frequency division multiplex of one transponder. The 1.6-megabit channels are time-division multiplexed with four ships using each channel. Thus 4-channels/satellite with four users per channel and two satellites provide capability for 32 users.

Although only 0.4-Mbps usage ship-to-shore is discussed, a total system could provide voice and low-rate data link in both directions for a larger number of users than the 32 served by the 0.4-Mbps link.

The total satellite system cost is estimated at $100 million which is felt to be conservative. This includes three satellites and launch vehicles plus two master ground stations.

Assuming the $100 million investment is to be recovered in 2 years and that all available channel time can be sold, satellite costs per user/month are

$$\frac{\text{100 million}}{\text{(32 users) x (24 months)}} = \$130{,}000\text{/Month}$$

Adding ground station costs give total per month costs of $133,000 per user.

Cost per hour assuming continuous transmission is $180.

These cost estimates are conservative, and a closer look could lead to reductions of 1/2 to 3/4. However, considering the huge expenditures for oil exploration ships, the costs shown are not out of reason.

A cost-effective land-mobile system could be similarly synthesized.

III. DATA SECURITY

Data security would be maintained by scrambling data as well as separating data for each user at the ground station so that individual users do not see all data. It is, however, feasible for an unwanted party to monitor satellite downlink transmissions, record them, and subsequently, by diligent application of cryptographic techniques, decode the data. Reasonably simple and efficient methods could be used for security, making intervention by unwanted users economically unfeasible; i.e., cost greater for unauthorized user to decode each data transmission than for him to survey himself.

The cost for data security is a small part of the total cost per user. Security techniques also will use a negligible portion of the total data rate.

APPENDIX H

FIELD DATA SYSTEM DESIGN USING CHARGE-COUPLED DEVICES AND HIGH-DENSITY TAPE

I. DATA SYSTEM DESCRIPTION

Based upon the approach defined in Volume 1, Section III-A-5a, the data system block diagram of Figure H-1 is proposed. Vibroseis is assumed as the energy source, but other sources could be used.

To establish a basis for understanding the functions defined in Figure H-1, the hypothetical characteristics listed in Table H-1 for a land-seismic survey will be assumed. In this example, there are 48 geophone groups, each consisting of 54 geophones whose outputs are added into a common output line.

A. RECORDING

Referring to Figure H-1, the first element of the design approach defined in Section III-A-5a of the main text is satisfied by digitizing, formatting, and recording the incoming data from the geophones. Each of the 48 geophone group outputs is a separate data channel which is digitized and formatted for recording. Using a small rugged commercially available airborne-compatible digital tape recorder, the data for one shot with 48 geophone groups can fit in a small fraction of a single reel (the 9200-ft reels accommodate 25,000 bits/inch/track or greater than 250,000 bits/in^2). Assuming all 48 geophone group outputs are multiplexed onto a single track, a record rate of 1 7/8 ips is proposed for each shot. Referring to Table H-1 this would provide 2 days of continuous recording per track or more than 20 days of continuous recording at 8 hrs/day for 10 tracks resulting in approximately 100 miles of survey per reel of tape.

For subsequent processing, the recorder played back at a 32:1 speed-up, i.e., 60 ips. The output from the tape recorder would be a serial line sequentially providing the recorded output of each geophone group for a particular shot. The typical 16-second chirp time for Vibroseis would be reduced to 0.5 second in the playback mode.

B. I/Q CONVERSION

The first operation performed upon the geophone output data when read from the tape recorder would be an I/Q conversion. This would translate the seismic data into real and quadrature components centered around a zero baseband. The basic operation is illustrated in Figure H-2, wherein the (10-80 hz) digital data, stored on the wideband tape recorder, are one input. The other input is a digital frequency-control line used to control the frequency of an internal digital local oscillator. The incoming seismic data from each geophone group are digitally multiplied with cos and sin signals to form the real and quadrature components. Envelope detection using low-pass digital filters produces the I and Q signal outputs.

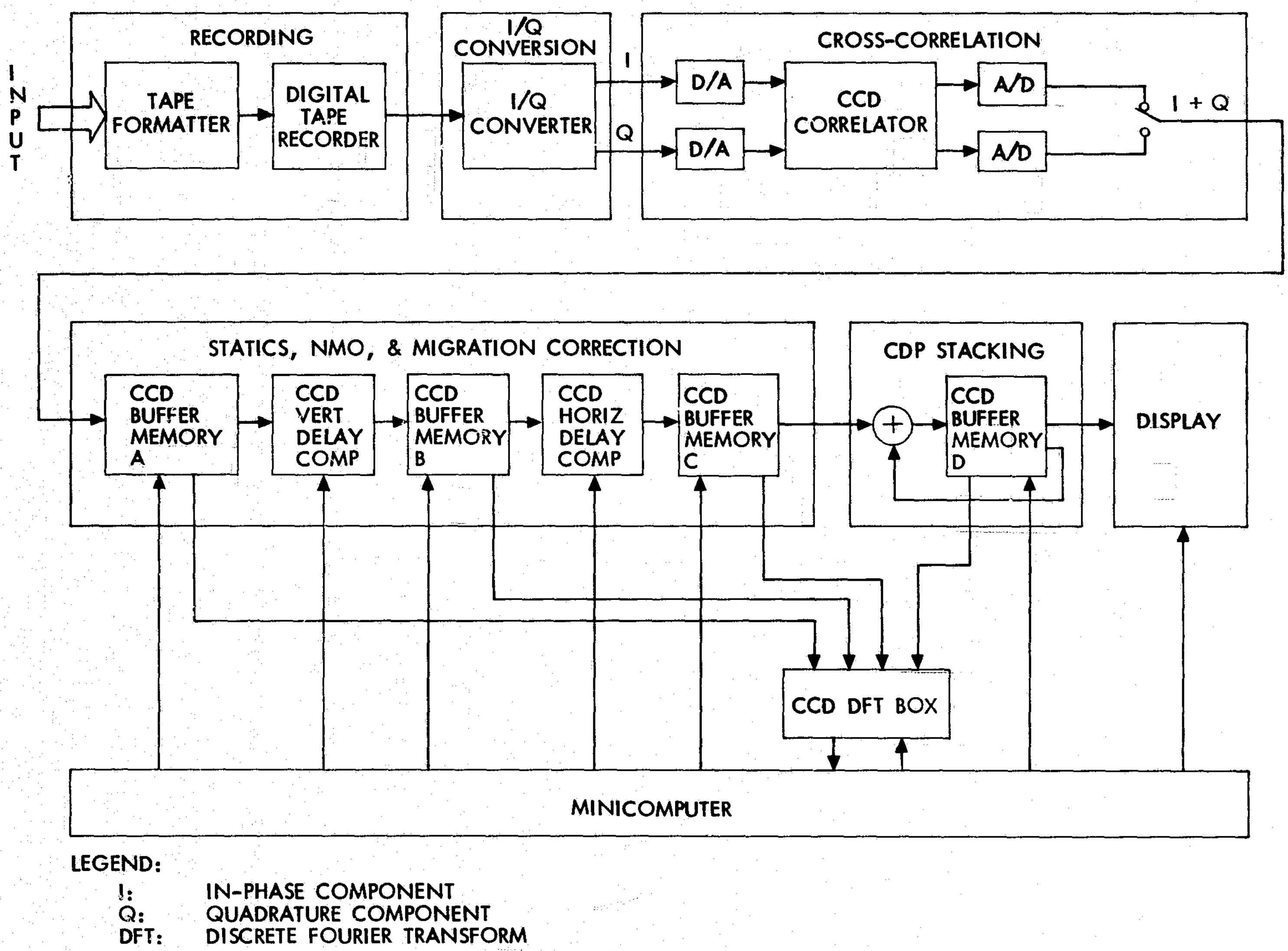


Figure H-1. Block Diagram of Seismic Field Data Processor Using Charge-Coupled Devices

Table H-1. Assumed Seismic Processing Parameters

Source	Vibroseis
Receiver	48 geophone groups (54 geophones/group) in single line
Chirp sweep	10-80 Hz
Chirp bandwidth	70 Hz
Sweep time	16 seconds
Sweep time x bandwidth ($T\Delta f$)	1120
Sampling rate	250 samples/s
Sampling repetition interval	4 ms
Quantization level	4 bits
Shot repetition interval	20 seconds
Data rate	40 kbps
Recording time	8 hrs continuous/day
Data volume	$\cong (1.2)(10^9)$ bits/day
Data capacity/tape reel	$\cong (3)(10^{10})$ bits

C. CROSS-CORRELATION

The I (in-phase) and Q (quadrature) signals for each sequential geophone-group trace are next correlated against the original chirp function transmitted by the energy source. Cross-correlation is accomplished in the analog time domain using CCD (charge-coupled device) transversal filtering. The I and Q signals are passed through D/A converters and applied to the CCD transversal filter configuration of Figure H-3. Since the signal time-bandwidth product (from Table H-1) is 1120, four length-1200 filters are proposed to accommodate the sin and cos components for the I and Q signals (the filter length must be greater then $T\Delta f+1$).

After the first 1200 samples, each sample clocked into the correlator will produce an output sample in real time that is the result of correlating with the original chirp function across 1200 points. Following correlation, the I and Q signals are digitized and interleaved into a common output line representing a pulse-compressed output signal in which both amplitude and phase information have been preserved.

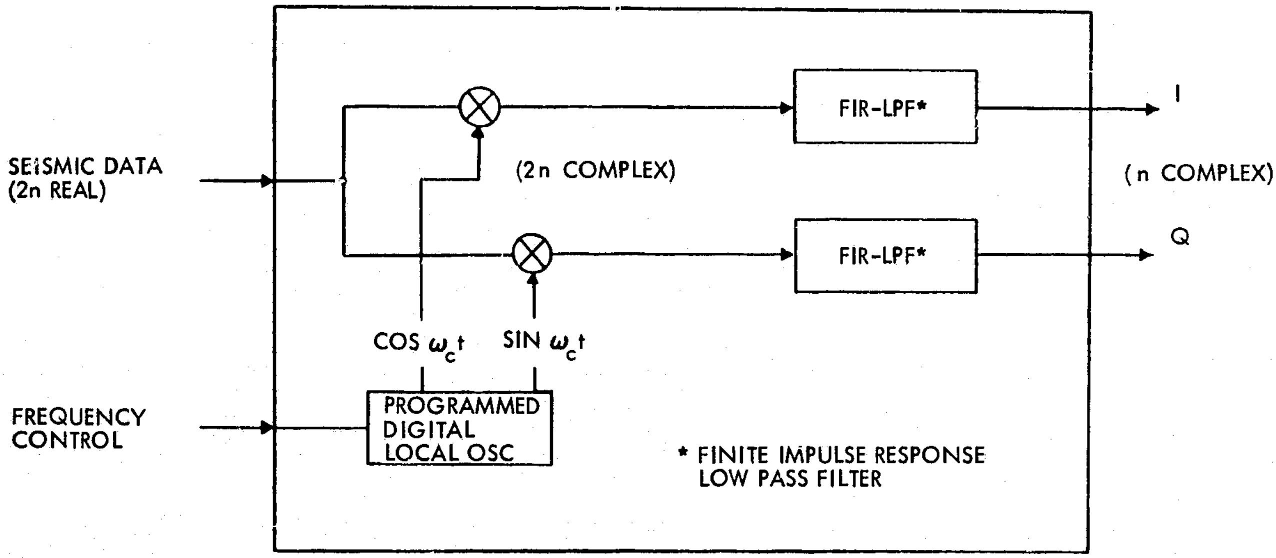


Figure H-2. I/Q Converter

D. STATIC AND NMO CORRECTIONS

For each shot point, there will be seismic traces corresponding to the number of geophone groups. The assumed requirements specified in Table H-1 would result in 48 seismic traces. The next operation is correction for static errors and normal moveout (NMO). These corrections can be made by relative placement of the data points within corresponding traces. A correction curve is computed based upon estimates of velocity characteristics, reverberation attenuation, etc. The correction is made by introducing an appropriate delay to each of the seismic traces.

A conceptual implementation for this correction in real time is illustrated in Figure H-4. Uncompensated common depth traces from a CCD buffer memory are passed through a D/A converter and shifted into a CCD serial-to-parallel converter (SPC). Each stage of the CCD SPC therefore contains data from a separate trace. The contents of the CCD SPC are then shifted in parallel into individual delay lines. By controlling the amount of delay in each line, the data points in any section of a seismic record may be shifted vertically in either direction by varying amounts relative to any other trace. The delay-line outputs are read out in parallel into a CCD parallel-to-serial converter (PSC). The data from the CCD PSC is then shifted out through an A/D converter and stored in a digital CCD buffer memory. Since the effective delays can correspond to any desired correction curve in the vertical dimension, each specific section of each output from the CCD PSC will be corrected for the effects of statics and NMO.

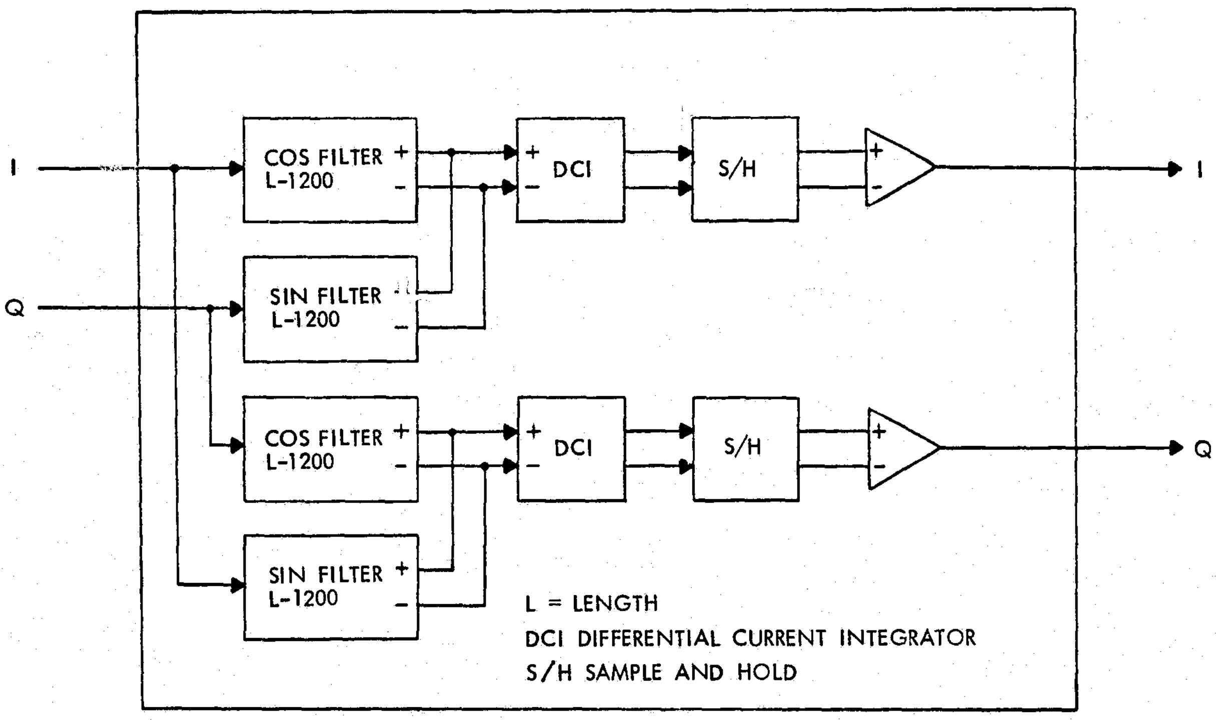
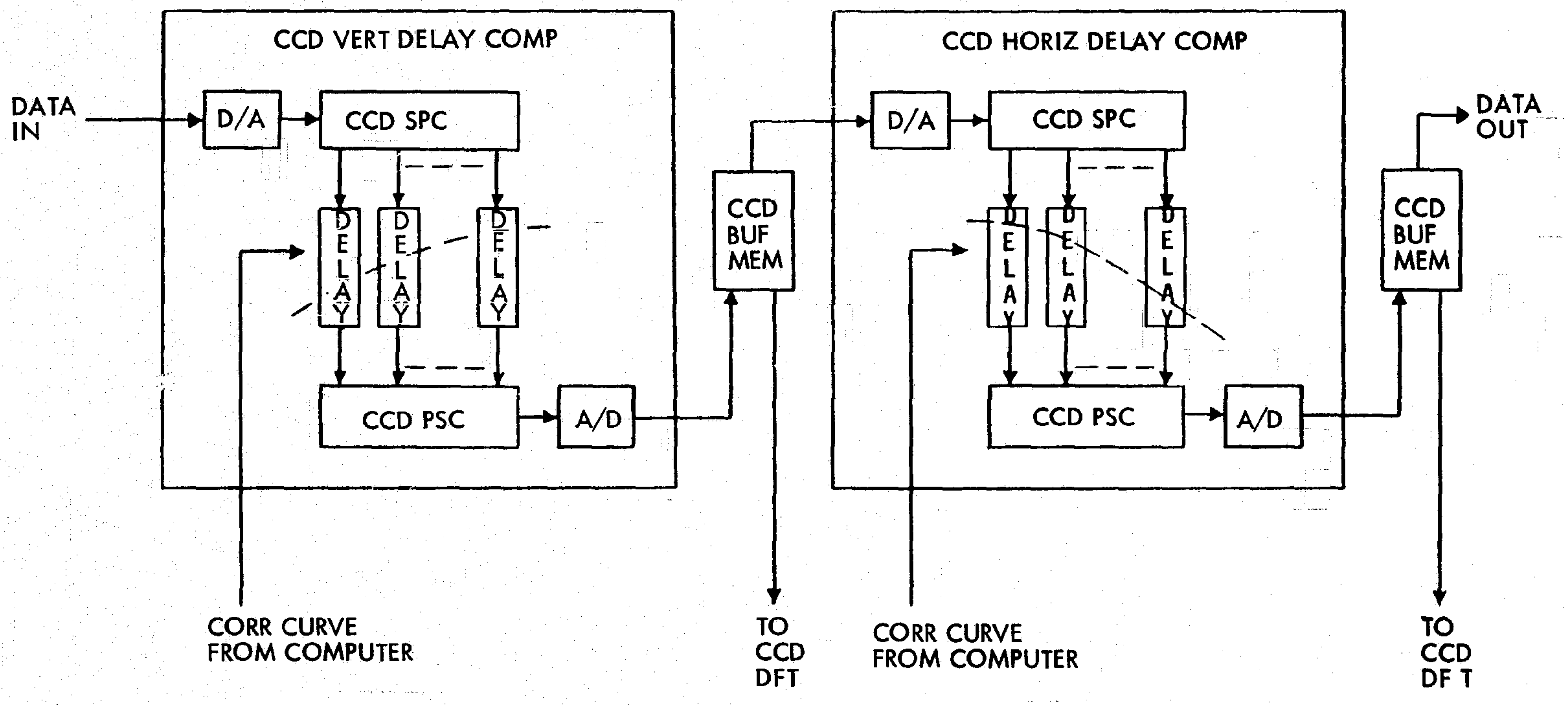


Figure H-3. CCD Correlator

E. MIGRATION

Correction for the vertical component of the migration correction is carried out in the same way as the static and NMO corrections. To correct for the horizontal components of the migration correction vectors, the data are rotated 90° in the digital CCD buffer memory at the output of the vertical compensator of Figure H-1 and shifted into the horizontal compensator. As noted from Figure H-4, the same basic operation is carried out as for the vertical dimension. In this case, groups of n samples, each representing the same vertical section for a different seismic trace, are sequentially shifted into a CCD SPC following a D/A conversion. By passing data from the CCD SPC output stages through individual delay lines, the relative position of each data point may be shifted horizontally by varying amounts in either direction relative to other data points in the matrix. The delay-line outputs are again read into a CCD PSC, digitized, and stored in a digital CCD buffer memory.

It should be noted that Figure H-4 depicts a conceptual implementation only. If a single delay line per stage were implemented as described, precise correction to fit a desired curve would be very difficult. Since the data are sampled, a precise curve fit would require a resampling process. Although, the correction could be approximated using interpolation techniques, this would introduce an undesirable level of complexity.



LEGEND:
SPC: SERIAL-TO-PARALLEL CONVERTER
PSC: PARALLEL-TO-SERIAL CONVERTER
DFT: DISCRETE FOURIER TRANSFORM

Figure H-4. Two-Dimensional Correction

To accomplish a precise compensation with no need for interpolation, the implementation of Figure H-5 is proposed. The output from each stage of the CCD SPC is read into an N-stage register where N is the maximum number of data points over which correction is required. To perform compensation, it is necessary to be able to select the information from any location within each register to form the desired delay. The net effect is the same as being able to slide the data in each line of one dimension of a matrix in either direction until the desired samples are in the proper matrix position for that dimension. To avoid interpolation and achieve a precise correction, it is necessary to reconstruct the correction curve within the desired matrix location and effectively resample on the curve at that location. This can be accomplished by using the (sin X)/X algorithm shown in Figure H-6. If the contents of an N-stage register of Figure H-5 are convolved with a digitally sampled (sin X)/X function, the original signal will be produced. However, by shifting the phase of the (sin X)/X signal so that it is sampled at different points, the same signal will again be reproduced following convolution, but it will also be sampled at different points corresponding to the phase shift of the (sin X)/X signal. Thus, a precise resampling within the matrix may be accomplished to accommodate the desired correction curve exactly.

F. COMMON DEPTH POINT STACKING

For a given shot, the correlated and corrected output data for each geophone array are digitized and stored in a separate digital CCD memory chip of a buffer memory. Referring to Figure H-7, assume that the shot point is moved a distance of one spacing interval between geophone groups for the subsequent shot. The next shot would therefore produce an output from group 2 corresponding to the same reflection point as that produced from group 1 on the previous shot. The same relationship would exist for group 3 to group 2, group 4 to group 3, etc. Therefore, summing the output of group 1 from shot 1 to group 2 from shot 2 to group 3 from shot 3, etc. will provide a single depth line having multiple-look characteristics for each depth point. This is generally called common depth point (CDP) stacking and provides a significant improvement in S/N characteristics of the signal, assuming the stacked traces are statistically independent. A further advantage of the stacking operation is that the data volume is reduced by the number of shots, i.e., for the requirement specified in Table H-1, the data from n shots would be combined to form a single output during the stacking operaton.

Referring to Figure H-1, a CDP stack is performed following each shot. The correlated and corrected output data for each geophone group are transferred from CCD buffer memory C and summed with the appropriate geophone data from the preceding shots stored in CCD buffer memory D. The resultant sums are transferred to and stored in CCD buffer memory D, replacing the previously stored sums. These new sums are then read from CCD buffer memory D following the subsequent shot and summed with the appropriate new geophone group output data from CCD buffer memory C. CDP stacking is done for each shot so that the number of seismic traces stored in either buffer memory never exceeds the number of geophone groups.

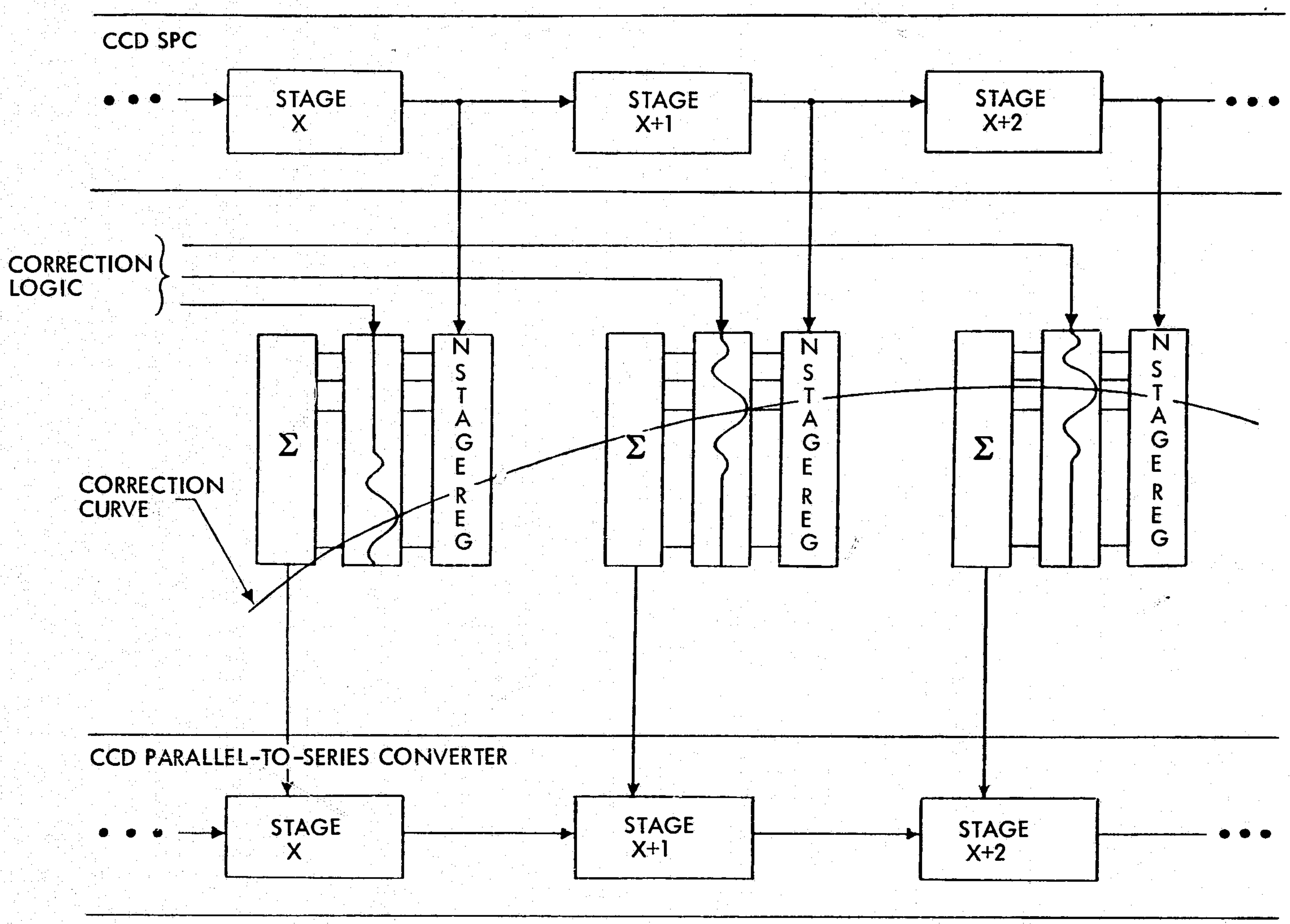


Figure H-5. Delay Correction Processing

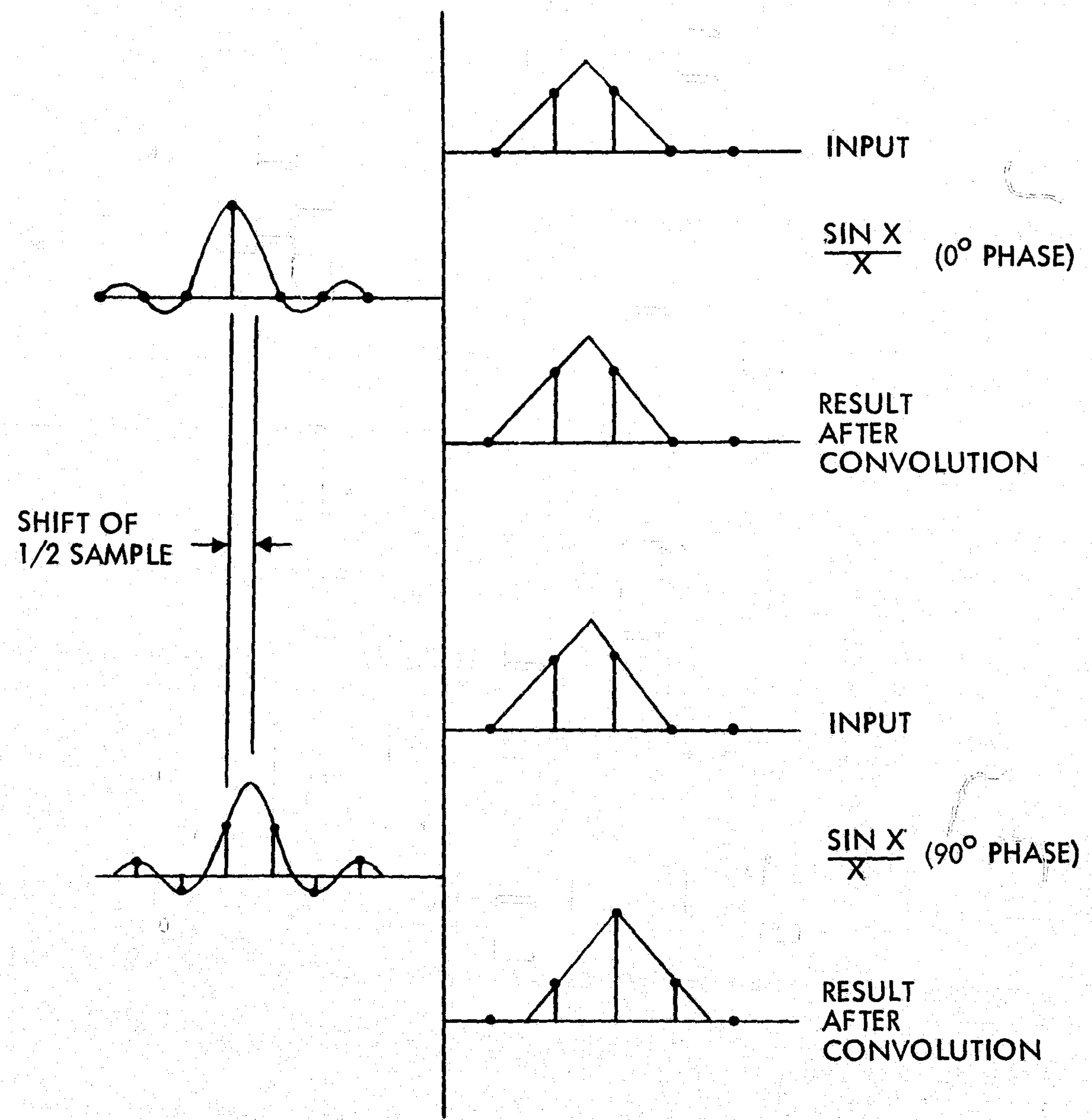


Figure H-6. Delay Correction Algorithm

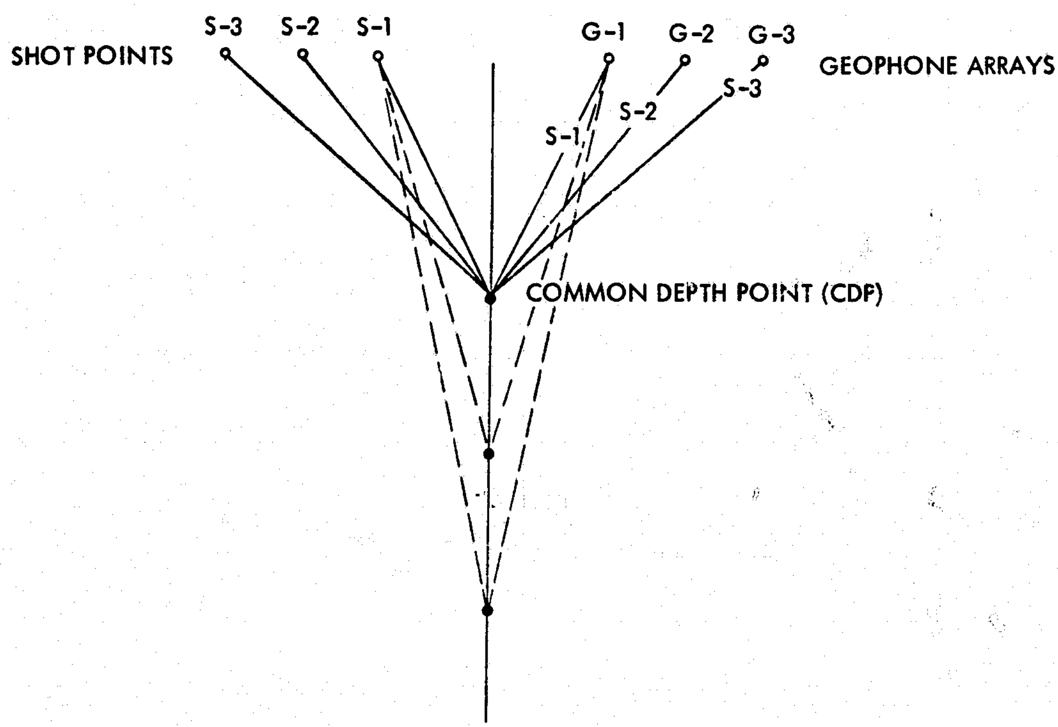


Figure H-7. CDP Stacking

G. PARAMETRIC CORRECTION AND CONTROL

As noted in Figure H-1, the recording, I/Q conversion, and cross-correlation operations can be done with a hardware processor requiring no interim data analysis or corrections. On the other hand, following correlation, data corrections for the effects of statics, normal moveout, and migration require software analysis of existing data in order to determine the correction curves to be effected. Furthermore, corresponding seismic traces must be analyzed and properly aligned prior to CDP stacking. This requires analysis of data before and after correction and most certainly will involve an iterative process in order to achieve optimum results.

Referring to Figure H-1, seismic data are supplied to a minicomputer from digital CCD buffer memories (1) before and after vertical and horizontal compensation, (2) after total compensation, and (3) after CDP stacking. Since the best form for the computer to analyze the data is in the frequency domain, analog devices capable of performing the Discrete Fourier Transform (DFT) and the inverse DFT (DFT^{-1}) functions are provided external to the computer. These functions are implemented with CCDs using the Chirp-Z Transform (CZT) algorithm. Using the CCD CZT implementation approach, the equivalent of a digital Fast Fourier Transform (FFT) can be achieved with a very significant reduction in complexity. Furthermore, the requirements imposed upon the computer are also greatly simplified.

Computer analysis is performed using data from CCD buffer memories A, B, and C to define the corrections needed to compensate for the effects of statics, NMO and migration. The desired correction curves are determined by the computer and provided to the vertical and horizontal compensator circuits described in the preceding sections. Although the field conditions may not allow an ideal correction capability to be achieved, significant improvements in data content and quality should be possible under quick-look field conditions to render such a field correction capability cost-effective in many cases.

It should also be noted that the proposed techniques for achieving the corrections are not limited to field operations. They should also contribute to a more cost-effective approach for achieving correction optimization and detailed analysis at a central-processing center.

Based upon the data input from CCD buffer memories C and D, the spectral characteristics of the seismic traces prior to stacking are compared. For instance, the equivalent of a convolution in the time domain can be achieved in the frequency domain to detect the optimum alignment for maximum correlation by performing a frequency multiplication after a DFT and then applying an inverse DFT (DFT^{-1}) function. Following such analysis, readout from memories C and D is controlled by the computer so that the optimum alignment within the data is achieved for the summing process.

II. DESIGN ANALYSIS

The proposed data system design described in Section I uses CCD technology to greatly simplify the implementation and operational requirements for a seismic data processor. The net result should be more information in a shorter time at a lower cost.

The critical elements of the data system design of Figure H-1 that must be successfully designed and developed in order to realize these benefits are technically evaluated in the following paragraphs.

A. HIGH-DENSITY TAPE RECORDER

The proposed recording system shown in Figure H-1 consists of a digital tape formatter and a high-density digital tape recorder. Equipment that would be directly applicable for these functions has already been developed and used for a similar application during 1975 and 1976 (Reference JPL Contract 954340). In that application, synthetic aperture radar (SAR) echos were formatted and stored prior to processing into images. Since the equipment was used for field applications, it is compact and rugged. Therefore, it is ideally suited for transporting over rough terrain in a van or truck.

The primary purpose of the digital tape formatter is to receive, digitize, and properly format the analog signals from the geophones for recording on high-density magnetic tape. An attractive implementation for the tape formatter is illustrated in Figure H-8. Referring to Figure H-8, a separate A/D converter and buffer memory (which could be implemented on a single chip) capable of instance, the equivalent of a convolution in the time domain can be achieved for each channel. After the shot, all of the digital data from group 1, corresponding to a complete seismic trace, is read out through an output multiplexer and recorded on the high-density digital tape recorder. When the output data from group 1 are recorded, the output multiplexer switches to the next channel so that the seismic trace for group 2 is recorded on tape. In this manner, the seismic traces for each of the groups are sequentially recorded on tape. In addition to the digitized echo signals, other information such as line number and synchronization (for later use by the deskew electronics) would be formatted into the data stream for recording.

The high-density digital magnetic tape recorder proposed for this application is the Sangamo Sabre III. It has been specifically designed for field van, shipboard, and aircraft applications. Typical operating ranges for temperature and humidity are 5 C to 50 C and 5% to 95%, respectively. The recorder is also designed for operating at altitudes up to 30,000 ft. In the nonoperating mode, the recorder is capable of survival at much greater extremes.

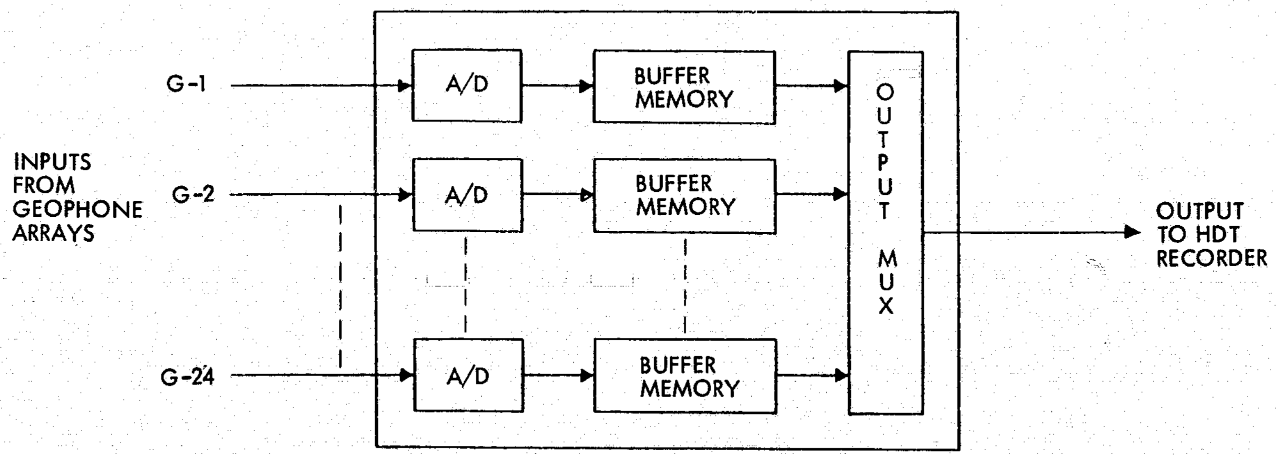


Figure H-8. Digital Tape Formatter

The proposed record and playback speeds of 1 7/8 ips and 60 ips, respectively, are standard on the Sabre III recorder. The recorder accepts data from the digital tape formatter on 14 tracks. The recorder uses 3M type 888 1-inch magnetic tape. The reels are 14 inches in diameter holding 9200 ft. of tape. Assuming the use of 10 data tracks, each such reel will accommodate approximately 160 hours of continuous recording at 1 7/8 ips.

The tape recorder peripheral equipment includes deskew electronics and power supplies, both of which are commercially available. If data are recorded in parallel on multiple tracks, the deskew electronics unit is used to assure that all of the bits for a given word of data are outputted simultaneously during the playback mode. The deskew electronics provides special signals that are recorded with the data during the record mode. These signals are then used by variable delay circuits contained in the deskew electronics to align the individual bits during playback.

Although all of the data from an entire seismic exploration program are stored on high-density tape from which processing is accomplished via direct interface with that tape, it <u>may</u> be desirable to produce some computer-compatible tapes (CCTs) from the high-density tape during testing in the field for special purposes. This could be done using a system identical to that already developed and used on the previously mentioned synthetic aperture radar program. A block diagram of the data reformatting system for making CCTs in the field is shown in Figure H-9. The system was mounted in a field van and used in the field to make CCTs of selected data of interest.

Referring to Figure H-9, the high-speed digital interface (HSDI) unit permits connection between the high density tape recorder and a minicomputer. For the seismic application, this would be the same minicomputer as shown in Figure H-1. The HSDI connects the output of the deskew electronics to a 9-level (including parity) binary code. It also displays each record number (line number) as it occurs. The output of the HSDI is delivered to the minicomputer, which in the SAR application was a TI-960A digital computer. In accordance with the stored program, the data is properly formatted for recording onto the digital tape unit. In the reformatting process, the 8 most significant bits of each data word are organized into a 9-track IBM compatible format with the ninth bit used for parity. Each digitized line of data is then organized into a record. Each record is then identified with a unique record number that is determined when the data is originally recorded.

The digital tape transport of Figure H-9 provides the means for recording data in computer-compatible format. All functions of the transport except for the high-speed rewind are controlled by the computer.

The card reader of Figure H-9 permits loading of both the data control supervisor program and the format translator program. These programs must be loaded prior to execution of the reformatting process. The card reader may be operated either manually or under computer control.

The terminal unit of Figure H-9 permits operator interaction with the computer and its programs. Information such as the data, number of records to be translated, etc. are output through the keyboard.

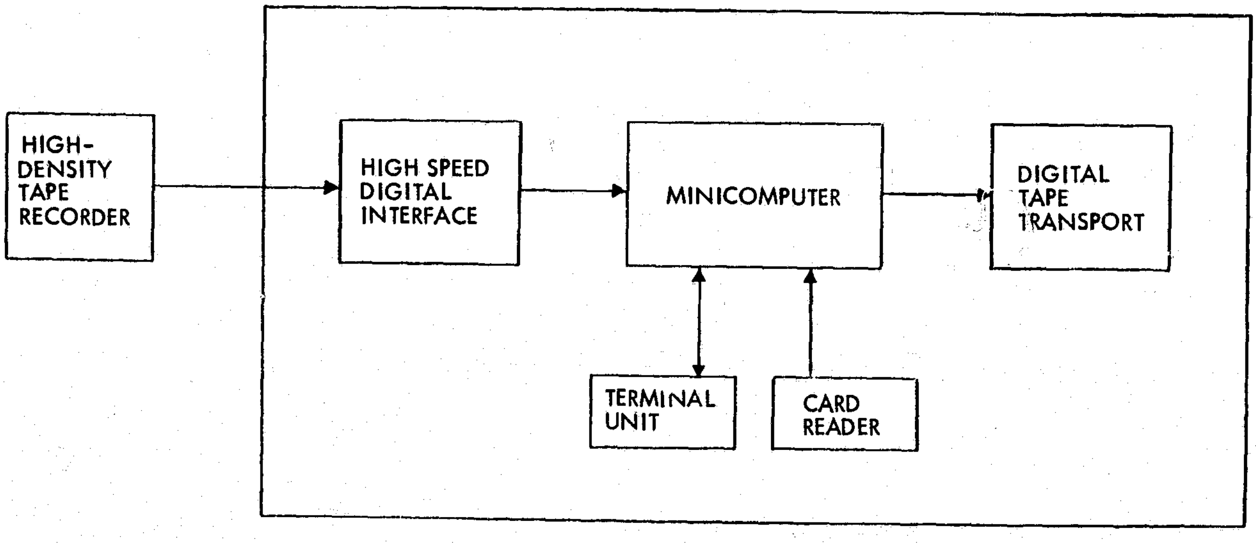


Figure H-9. Data Reformatting System

In summary, the high-density tape recorder system of Figure H-1 could be built with only minor modifications to already existing or demonstrated hardware designs. The seismic processor proposed herein does not require CCTs. The number of generated tape reels can be greatly reduced from that of standard practice. The data system design does include the capability of making CCTs in the field as if desired.

It is estimated that the entire recording system as proposed herein could be developed and implemented into the integral seismic data-processing system of Figure H-1 for less than $80,000.

B. I/Q CONVERTER

An I/Q converter identical to that shown in Figure H-2 has already been developed by industry and used for SAR image-processing applications. It would require only minor modifications for use with seismic data. The cost to provide the I/Q converter for integration into the seismic data-processing system of Figure H-1 is estimated to be $20,000.

C. CCD CORRELATOR

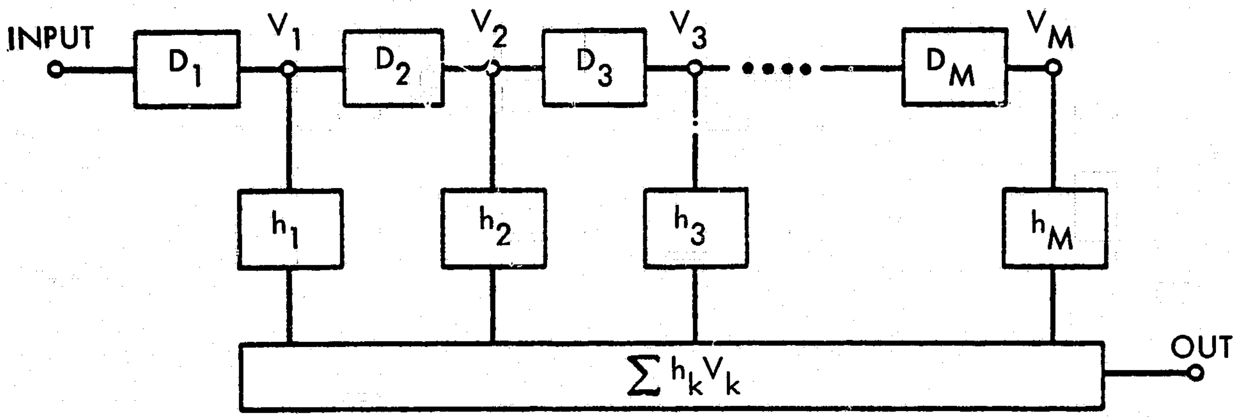
It is proposed to accomplish the cross-correlation function of Figure H-1 by means of analog CCD transversal filters. As noted from Figure H-3, four such filters would be required to accommodate the sin and cos components for the I and Q signals. The peripheral functions of D/A and A/D conversion can be done by commercially available IC chips.

A CCD transversal filter configuration is shown in Figure H-10. The device functions as an analog signal shift register. In Figure H-10(a), the stages of the shift register are depicted as D_1, D_2, etc. Each of these outputs is nondestructively interrogated and weighted or multiplied by a factor h_K. These weighted outputs are then summed in a common summation network. This configuration, as a total entity, provides the transversal filtering function.

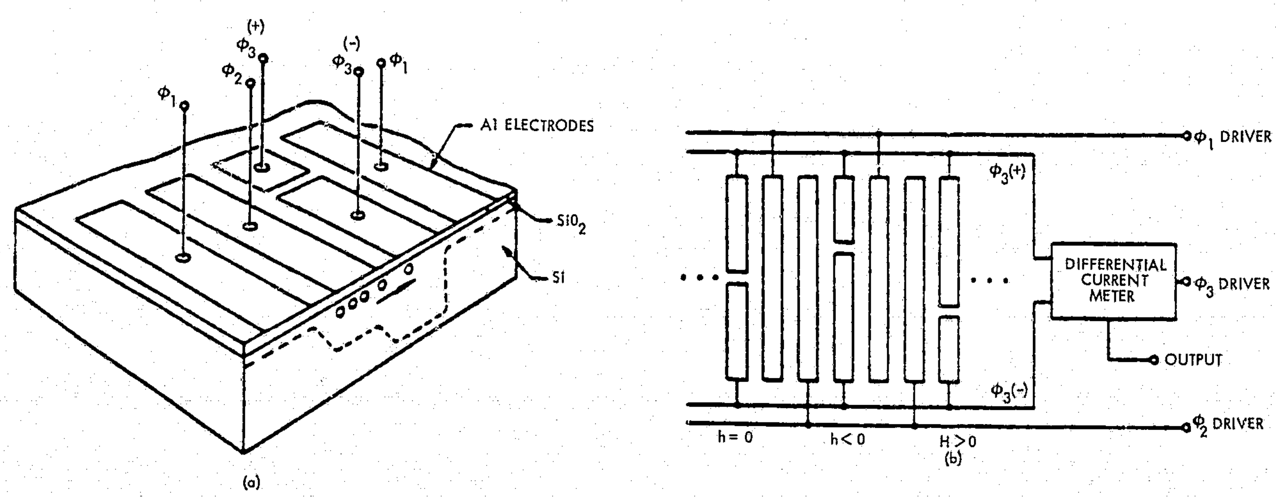
To illustrate how the cross-correlation function is achieved, assume that weighting H_1 through H_M is that of the originally transmitted chirp function. Furthermore, assume that each sample of the sampled seismic reflection data is shifted through stages D_1 through D_M of the filter. Once the register is filled, a complete correlation of all M points in the register with the chirp function is automatically accomplished and a correlated output produced for each seismic data sample shifted into the register. The cross-correlation function is therefore achieved by nothing more than shifting the seismic data through a shift register.

Where the weighting function does not have to be programmable, an extremely simple means of CCD electrode weighting can be achieved. As illustrated in Figure H-10(b), the transfer of charge from well to well is normally accomplished by multiple-phase clocking. Therefore, a 3-phase clocking system would have 3 transfer electrodes for each well. Furthermore, the driver current passing through each electrode is directly proportional to the charge being transferred. Therefore, if an electrode for one of the phases were divided into two parts and each part connected to a different input line of a differential current meter, a signal would be produced which is a function of where the gap occurs. For instance, if the gap were in the center of the electrode, the current in each of the lines to the differential current meter would be equal, and the net output would be 0. As the gap is moved away from center, the signal will become greater with a polarity which is a function of which line has the larger electrode section. If the corresponding driver lines for all of the electrodes for a given clock phase are connected together and these electrodes tapped as described, the functional transversal filter of Figure H-10(a) is achieved. Such a filter is designated as a fixed-tap weighted filter. The weighting function can be anything desired (chirp, PN, etc.) and is implemented by an electrode etching process. A different weighting function can be implemented during manufacture by simply using a different mask during the etching process.

CCD fixed-tap weighted filters with chirp function weighting have been developed and successfully used for several processing applications during the past several years. One of these applications is that of synthetic aperture radar image processing where several CCD transversal filters have been included on a single chip. The closest filter to the requirement specified for the seismic application that is already developed and demonstrated is a length-800 CCD filter. To meet the data system design requirement specified in Table H-1 and illustrated in Figure H-3, a length-1200 CCD filter would be required. This could be accomplished with minor modification to the existing length-800 filter chip design. Approximately 12 months and $100,000 would be required to develop the new chip for the correlator after which production chips would cost less than $15 each. It is estimated that the cross-correlator unit could be developed and integrated into the seismic data-processing system of Figure H-1 within 18 months for a cost of less than $150,000 at very minimal risk.



(a) **CCD Transversal Filter with Fixed Weighting Coefficients**



(b) **CCD Electrode Weighting Technique**

Figure H-10. CCD Transversal Filtering

D. CCD BUFFER MEMORY

Referring to Figure H-1, four CCD buffer memories are included in the proposed seismic data-processing design. In all cases, the buffer memories are organized to store individual seismic traces on a first in-first out basis and have a capacity capable of storing a number of seismic traces equal to the number of geophone groups. Referring to Table H-1, a trace consisting of 4000 samples would require 16,000 bits for 4-bit quantization. The proposed memory design would accommodate all of the data for a seismic depth line on a single CCD IC chip. In order to store 16,000 bits on a single chip, a CCD serial-parallel-serial (SPS) memory plane is proposed. A typical SPS memory plane organization is illustrated in Figure H-11. Referring to Figure H-11, the data are read into the memory plane in serial and transferred in groups of 200 bits through the memory plane in parallel. If 80 such groups are accommodated, the storage capacity will be 16,000 bits. Just as the data is clocked serially into the memory, it is also read out in serial form from the last 200-bit group. As the last bit in the last 200-bit group location is read out, all 200-bit groups are shifted in parallel through the memory plane one position so that the last 200-bit group location is again filled. Serial readout can therefore continue on an uninterrupted basis.

Several points concerning the CCD SPS memory organization are worthy of note. It is truly a first in-first out organization. The first bit in will be the first bit out, the second bit in will be the second bit out, etc. In other words, it is functionally the same as a long-serial shift register. However, compared to a long-serial shift register, each data bit of information sees more than an order of magnitude reduction in transfers through the memory. For instance, in Figure H-11, each data bit will only transfer through 280 stages between input and output as opposed to 16,000. This greatly simplifies the implementation considerations so that the entire 16,000-bit SPS array can be accommodated on a single IC chip. Comparable CCD SPS memory planes have already been fabricated and demonstrated. Furthermore, CCD imaging arrays of 400 x 400 (equivalent to 160,000 bits) have been successfully accommodated on a single chip. Therefore, CCD SPS arrays of much greater than 16,000 bits on a single IC chip appear practical.

Each CCD buffer memory defined in Figure H-1 would be required to store 48 seismic traces. Since an entire trace is stored on a single IC chip, each memory would require 48 storage chips. It is estimated that the development of the basic SPS chip would require 18 months and $100,000. Production costs of additional memory chips should be less than $15 per chip. The total cost of developing the four CCD buffer memories, plus their peripheral circuitry, for integration into the seismic data-processing system of Figure H-1 is estimated to be $150,000 over a period of 2 years.

E. CCD DELAY COMPENSATOR

Referring to Figure H-4, the D/A converter, CCD SPC, CCD PSC, and A/D converter functions for the vertical and horizontal delay compensator blocks described above require no new development. The D/A and A/D converters can be procured as commercially available chips. The CCD SPC and CCD PSC represent nothing more than analog CCD shift registers for which proven chip designs exist.

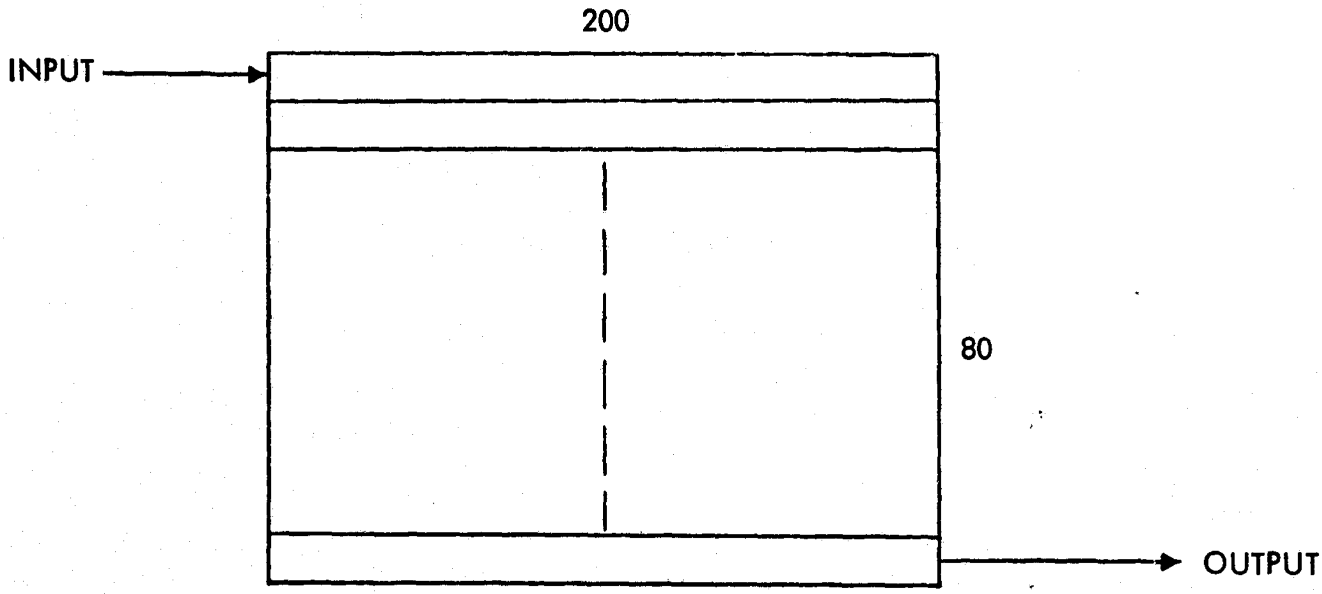


Figure H-11. CCD Serial-Parallel-Serial (SPS) Memory Plane

On the other hand, the delay stages, wherein delay selection and resampling are accomplished through convolution with the (sin X)/X function, require the development of a custom CCD chip for practical implementation. Although each delay stage of Figure H-4 could be implemented with currently available digital IC chips, it would require approximately 70 chips per stage and an impractical power demand. Both hardware and power requirements could be reduced by two orders of magnitude using CCD technology.

A practical implementation approach for the custom CCD chip to perform all of the operations required for a single delay stage of Figure H-4 is illustrated in Figure H-12. Referring to Figure H-12, the (sin X)/X function is provided from the computer to the delay compensator chip in the form of 32 6-bit words and stored in a 32 X 6-bit MOS register. (The significance of 32 stages is somewhat arbitrary as it represents the number of stages over which delay compensation may be applied to a single seismic data point. If more stages are required, no particular limitation results up to several hundred stages.) As noted in Figure H-12, six CCD length-32 1-bit correlators are provided. Each such correlator stores the same information for a given seismic line. One correlator is used to accomplish convolution with the most-significant-bits (MSBs) of the (sin X)/X words. The other correlators are used for convolution with the corresponding sets of bits of descending significance. For example, the last correlator convolves the seismic line data with the least-significant bits (LSBs) of the (sin X)/X function stored in the MOS shift register. By properly weighting the correlator outputs to represent their appropriate significance (2^5 for MSBs through 2^0 for LSBs) and summing the results, an analog signal representing the convolution of the (sin X)/X function with the seismic line data results. This analog signal will represent a resampled version of the data stored in a given location of the CCD correlator.

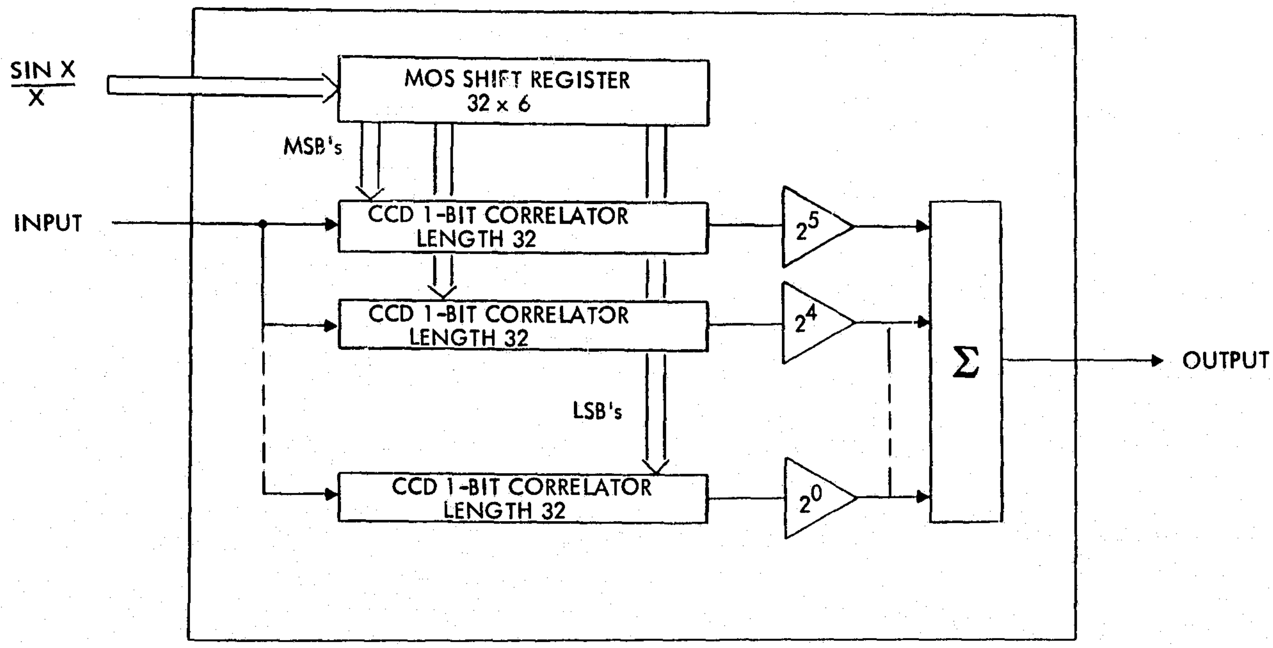


Figure H-12. CCD Delay Compensator Chip

The location and resampling is a function of the location and phase characteristics of the (sin X)/X function in the MOS shift register of Figure H-12.

The development of the single chip CCD delay compensator of Figure H-12 represents an application of current state-of-the-art technology and should entail minimal risk. It is estimated that such a chip could be fully developed for $200,000 over a period of 2 years. On this basis, the vertical and horizontal compensator blocks as defined in Figure H-4 could be implemented and integrated into the total seismic processor system of Figure H-4 within 2-1/2 years for a total cost of $250,000.

F. CCD Discrete Fourier Transform (DFT) BOX

To assist the computer in (1) analyzing the seismic data at various stages of processing and (2) determining the necessary corrections to and control of the data at these stages, a CCD Discrete Fourier Transform (DFT) box is included as an interface between the basic processor and the computer. As noted previously, this provides the functional equivalent of a digital Fast Fourier Transform (FFT) at a considerable reduction in complexity. For instance, a 100-point DFT and DFT^{-1}, including frequency multipliers and ROMs, could be implemented on a single CCD IC chip.

In addition to its use for general spectral analysis needs, the DFT box is capable of performing other complex-processing operations. For instance, it could provide the function of a programmable transversal filter. Instead of performing the filtering by convolution in the time domain (as described previously for the CCD correlator of Figure H-1), it would be accomplished in the frequency domain. The concept is based upon the fact that convolution in the time domain

$$y = x * h \tag{1}$$

is exactly equivalent to multiplication in the transform domain

$$Y = X \cdot H \tag{2}$$

Therefore, convolution could be achieved as illustrated in Figure H-13(a) by (1) performing the DFT using the Chirp-Z Transform (CZT) algorithm, (2) multiplying by the transform of the desired impulse response, and (3) performing the inverse DFT (DFT^{-1}). Implementation of the DFT using the CZT results in the block diagram of Figure H-13(b). Since two of the multiplication operations of Figure H-13(b) cancel, the block diagram of Figure H-13(b) could be replaced with the simplified block diagram of Figure H-13(c). From an implementation standpoint, the CZT and CZT^{-1} functions of Figure H-13(c) can be achieved by using CCD fixed-tap weighted filter chips as described previously for the CCD correlator of Figure H-1. In other words, programmability can be achieved using CCD fixed-tap weighted filters by working in the frequency domain. Convolution in the time domain was proposed for the CCD correlator of Figure H-1 assuming programmability was not required.

An application for programmable convolution using the DFT box might be for cross-correlation of corresponding traces from different shots before CDP stacking. This would provide the necessary information so that they could be properly aligned with respect to their corresponding correlation peaks (achieved from previous correlation with the transmitted seismic chirp function in the CCD correlator of Figure H-1).

Recently, hardware to perform a 500-point DFT using CCDs and the CZT algorithm has been developed. Furthermore, it has demonstrated the potential for significant reductions in system complexity and cost compared with currently used digital techniques (FFT, etc) for future applications requiring frequency spectral analysis and frequency domain processing. To realize this benefit for the seismic data processor proposed herein, it is estimated that the DFT box of Figure H-1 would require a $200,000-development effort over a period of 2 years.

G. DISPLAY

The seismic data processor of Figure H-1 produces an actual two-dimensional picture as opposed to the individual geophone-group output lines characteristic of conventional seismic graphic displays. Following two-dimensional compensation, the individual data points can be treated as independent pixels. As such, a convenient display for field processing would be a high-resolution TV monitor from which the seismic pictures could be observed and photographed in near-real time.

A display system using a commercially available high-resolution 9-inch TV monitor has recently been developed for real-time aircraft display of experimental synthetic aperture radar imagery (under JPL Contract 954340). Only minor modification to the scan converter would be required to make it directly applicable to seismic data. The cost to develop and integrate the real-time display system into the seismic data-processing system of Figure H-1 should be less than $10,000.

H. MINICOMPUTER

Numerous minicomputers are commercially available that should provide adequate computing and control capability to satisfy the field processing needs of the CCD seismic data processor of Figure H-1. The TI-990 minicomputer is suggested. It represents the replacement for the TI-960A which has already been extensively used for a similar application involving the processing of SAR echo data into images. Like the TI-960A, the TI-990 will have a rugged version which can be installed in a field van and used for field applications. The cost of integrating the TI-990 computer with peripherals into the seismic data-processing system of Figure H-1 is estimated to be $25,000.

III. PERFORMANCE ANALYSIS

Assuming the CCD seismic data-processing system of Figure H-1 were developed, the question of performance adequacy based upon existing seismic processing capability and needs is a vital consideration. Seismic data-processing performance characteristics of immediate concern for the proposed CCD implementation include dynamic range, storage time, charge transfer efficiency, computational capability, multiple application adaptability, and future growth potential.

A. DYNAMIC RANGE

One of the reasons that CCD technology has been virtually ignored by the seismic processing world to date appears to be related to previously established dynamic range requirements. With the widespread evolution of digital-processing technology in the late 1960s and early 1970s, a prime promotional selling point for seismic applications was that of dynamic range capability. It was demonstrated that digital computing technology could provide dynamic range capabilities up to 125 dB. Whether truly needed or not, this it tended to become a requirement for seismic processing. When CCD technology emerged in the mid-1970s, offering another major breakthrough in processing capability, digital technology had already imposed a heavy influence on the definition of seismic processing requirements. Since CCD devices exhibited a dynamic range capability of 60-80 dB, they were generally concluded to be inadequate without further consideration. Actually, a critical look at the real seismic processing needs as opposed to digital processing capability points out the potential fallacy of these conclusions. For a majority of the applications where up to 15-bit quantization is being used, 4-bit quantization should be adequate with insignificant loss in information content or quality, assuming variable signal gain-control is provided.

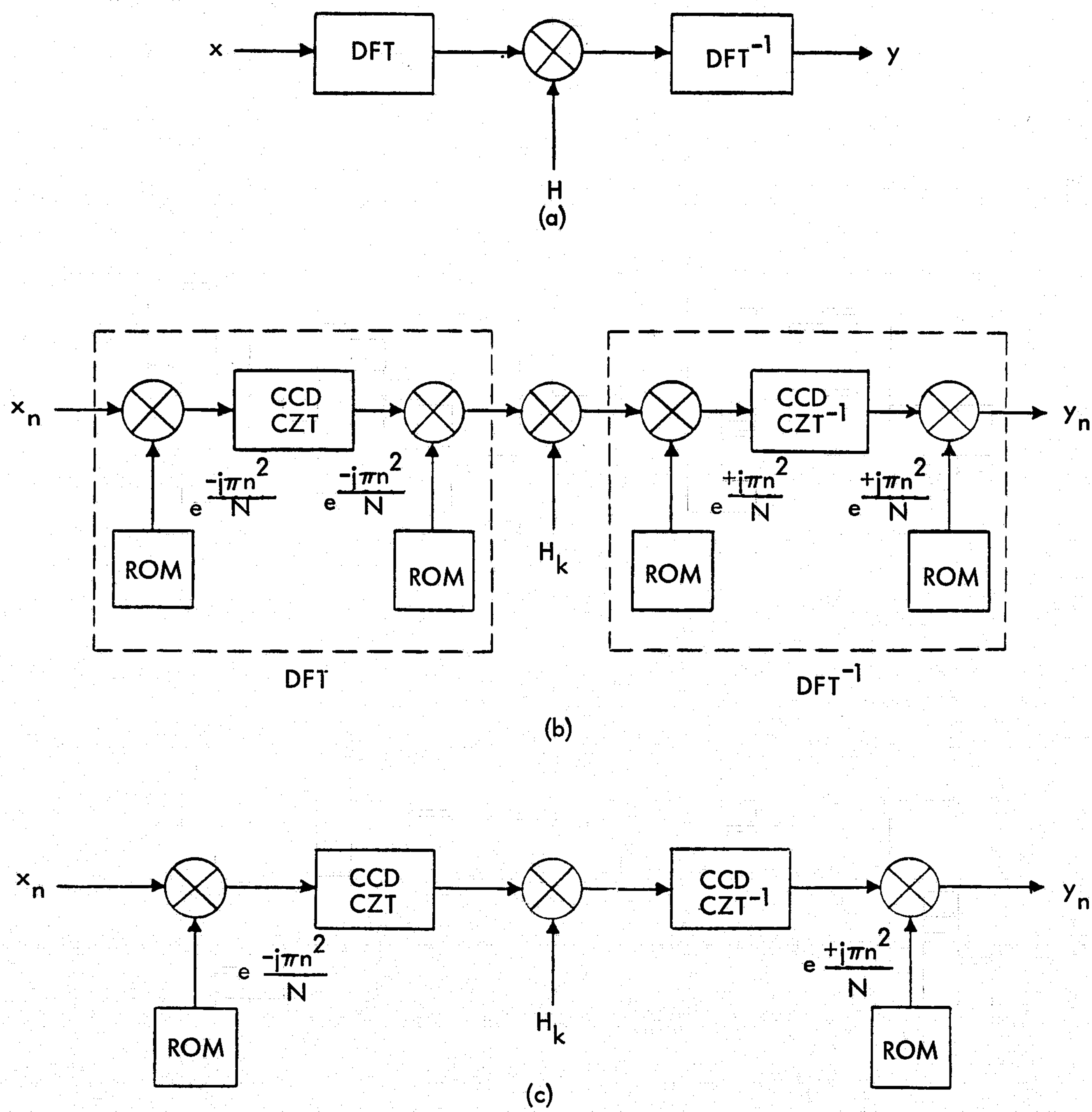


Figure H-13. CCD Programmable Transversal Filter

B. STORAGE TIME

Another frequently quoted reason why CCD technology has not been used for seismic processing applications is that of excessive storage time requirements. For instance, the 16-second chirp sweep time exhibited by Vibroseis is generally assumed to prevent the use of analog CCD processing to perform such functions as cross-correlation in real time because storage of a given analog charge packet in a CCD register generally cannot exceed about 1 second at room temperature without significant degradation. This is the result of a finite charge leakage that exists in the inherent semiconductor device.

The fallacy of the above argument is that a truly real-time processing capability is not required. For instance, the majority of the processing to be done on data from a shot is dependent upon data from preceding and subsequent shots. Obviously, data from a given shot must be stored if it is to be processed with data from a subsequent shot. Furthermore, it is desirable to store all of the received data intact so that it will be available for subsequent processing as desired at a later date. Therefore, magnetic tape, representing a cost-effective high-density storage media can be considered a practical requirement.

Although tape storage is required, it does not invalidate the capability of performing near real-time processing by accessing the data after recording. Furthermore, since the processed data are being accessed from a storage media in non-real time, the ability to achieve time compression becomes fully practical. For instance, for the data system design proposed herein, a 16-second chirp sweep, which was received and stored in real time, is read from storage at a 32:1 speed-up. Therefore, the effective chirp sweep time as seen by the CCD processor is compressed to only 0.5 second. Actually, the maximum storage time seen by any charge packet in the entire system of Figure 1 occurs in the length-1200 CCD transversal filters of the cross-correlator. Since 4000 samples must be shifted through the correlator in less than 0.5 second, the longest possible storage time for any charge packet would be less than 0.2 second. When longer storage times are required as in the CCD buffer memories of Figure H-1, the data is digitized so that the analog charge packet limitation does not apply. For other applications involving more data, greater time compression could be achieved by simply increasing the ratio of data-playback-rate to record-rate until CCD analog storage time considerations become inconsequential.

C. CHARGE TRANSFER EFFICIENCY

Since some charge is left behind when a charge packet is transferred from one CCD potential well to the next, the ratio of charge transferred to total charge available for transfer is termed the charge transfer efficiency. Although charge transfer efficiency is another limitation of analog CCD performance capability, it should offer no real problems for the seismic data-processing application. Typical values of charge transfer efficiency for current CCD devices exceed 0.9999. For the analog register lengths proposed herein, any degradation due to charge transfer losses would be insignificant.

D. COMPUTATIONAL CAPABILITY

In assessing the positive features of the seismic data-processing system illustrated in Figure H-1, the most outstanding is probably that of computational capability achieved as a function of hardware and software requirements. For instance, a single IC chip of the CCD correlator of Figure H-1 can replace several rack drawers of digital equipment at a fraction of the cost and power. Furthermore, a single IC chip in the CCD DFT box can accomplish the equivalent of both a digital FFT and inverse FFT thereby replacing complex and expensive digital processing equipment. Much of the CCD computational capability stems from the application of parallel processing techniques by which many digital operations, such as multiplies, can be accomplished simultaneously in one operation.

The net result of applying CCD technology is not only a gross simplification of hardware and software but a concurrent reduction in processing time and costs. As such, the achievement of a comparatively sophisticated processing capability in the field environment as well as a more cost-effective implementation for the central facilities can now become a practical reality.

E. MULTIPLE APPLICATION ADAPTABILITY

The proposed seismic data-processing system of Figure H-1 is intended to illustrate a representative architecture for seismic data processing. Although certain processing parameters were assumed in Table H-1, these were for illustrative purposes only. In other words, the basic architecture of Figure H-1 is in no way limited by these parameters. For instance, a different seismic source having a different time-bandwidth product would result in a different length CCD transversal filter. However, the future trend would probably be towards shorter filters, i.e., simplification, since more efficient energy sources would tend to have shorter sweeps.

In addition, seismic energy sources will most probably be improved so that higher frequencies will be available for processing. Again, this should have negligible impact on the CCD processor architecture. Comparable CCD processing techniques to those proposed herein have been designed to handle synthetic aperture radar echos having bandwidths of greater than 10 Mhz and clock rates up to 10 million samples/sec. Therefore, 200-Hz signals would introduce no problem.

Referring to the buffer memories of Figure H-1, it was noted in Section II that the single-chip storage potential using SPS techniques is much greater than the defined requirements. Furthermore, the number of storage chips per buffer memory was only 48 based upon the system parameters defined in Table H-1. It would appear that seismic tests involving thousands of geophones per shot could be accommodated by the data system architecture of Figure H-1. After all, the basic system involves minimal hardware so that it could be expanded in a modular fashion to accommodate greater processing demands.

One concern, as data source and processing demands increase for future applications, might be the load upon the computer. However, the proposed processing system does not process data on a truly real-time basis. Therefore, a tradeoff of overall processing turnaround time could be exercised since one has control of the amount, rate, and frequency of data transfer to the processor from magnetic tape storage.

An important point that should be noted is that applications of the data processing system of Figure H-1 are not limited to those where the energy source is Vibroseis. Although the CCD cross-correlator would not be used when a known signature is not inherent in the returned signal, corrections for statics, NMO and migration as well as CDP stacking could be done on both land and marine data using the techniques described herein. In all cases, the data would be converted into real and quadrature components using the I/Q converter so that each data point would be treated as a vector in a given spatial position.

To accomplish the pre-CDP stacking corrections, data point vectors would be transferred intact to different spatial positions using the vertical and horizontal delay compensation techniques described in Sections I and II. The need for such corrections regardless of source or environment is illustrated in Figure H-14 for the case of migration. As noted from Figure H-14, the information received by a geophone does not necessarily come from a reflection point midway between the source and the geophone as indicated in Figure H-7. In fact, it could come from any point on the path of an ellipse, having the source and geophone as focal points, depending upon the orientation of the reflecting surface. Therefore, the correct position would be determined and the data point vector migrated spatially to that position prior to display. Since correction for migration is currently not done on most seismic data because of cost, application of this partial processing function to both land and marine data may be one of the more important contributions of the CCD seismic data-processing system of Figure H-1. Following corrections, convolution between corresponding traces would be accomplished prior to CDP stacking using the DFT box described previously. Therefore, errors in alignment would be removed and compensation for discrepancies between shots achieved.

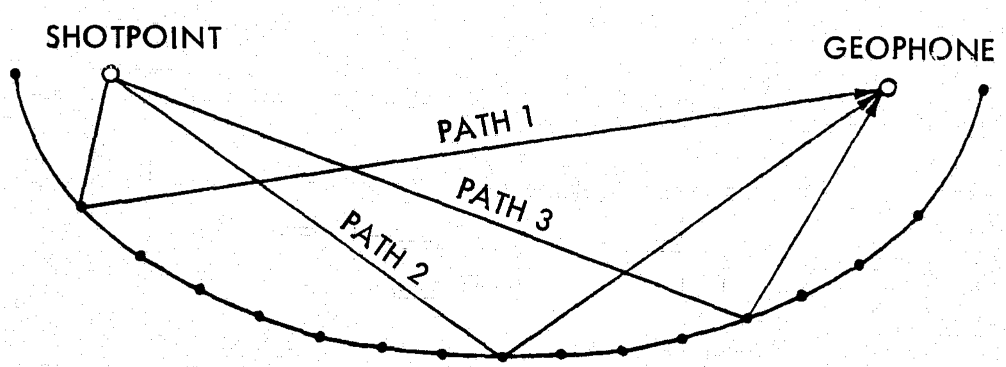


Figure H-14. Migration Characteristics

F. FUTURE GROWTH POTENTIAL

With respect to future growth potential to meet increasing demands, two aspects of the proposed CCD seismic data processor of Figure H-1 are worthy of note. The first is concerned with CCD technology itself. The proposed design with associated capability is based entirely upon the current state-of-the-art of CCDs. However, CCD technology is relatively new and improving rapidly. Therefore, it is realistic to expect significant performance breakthroughs which will increase the potential seismic data-processing capabilities, beyond those proposed herein, during the next few years.

The second consideration is that a more sophisticated processing capability than that proposed appears practical even with no advance of the current state-of-the-art. For example, 3-dimensional processing to accommodate 2-dimensional geophone arrays should be possible using the same techniques as those described in Sections I and II. However, such a system is somewhat more complex with respect to both system implementation and data interpretation. Since the proposed system of Figure H-1 provides a significant breakthrough in current seismic processing capability, it should be undertaken first to minimize cost and risk. If successful, it would establish a firm basis from which to undertake the development of a 3-dimensional field processing capability.

Table H-2 shows the cost breakdown for a development program.

Table H-2. CCD Seismic Data Processor Development Cost Breakdown (thousands of dollars)

HDT Recorder + Peripherals	80
I/Q Converter	20
CCD Correlator	150
CCD Buffer Memory	150
CCD Delay Compensator	250
CCD DFT Box	200
Display	10
Minicomputer + Peripherals	25
Power Supplies + Misc	25
System Design & Integration	250
Management and Management Overhead	350
Services/Travel	100
Procurement Administration	150
Documentation	90
Profit	150
TOTAL	2000

APPENDIX I

SIGNIFICANCE AND METHOD OF TIME DELAY SPECTROMETRY

I. THE IMPORTANCE OF PHASE

When two semiinfinite media of different acoustic impedances are in contact, acoustic waves propagating from one medium to the other reflect from the boundary. The strength of reflection depends on the contrast of ρV, the product of density and velocity of propagation. For normal incidence, the reflection coefficient is given by

$$R = \frac{\rho_2 V_2 - \rho_1 V_1}{\rho_2 V_2 + \rho_1 V_1}$$

The reflected wave is positive if the wave goes from a region of low impedance to one of high impedance. The reflection coefficient is independent of frequency and waves of arbitrary shape preserve their shapes on reflection.

The situation changes when there are many layers, particularly thin layers whose thickness is of the order of a wavelength. The change is due to multiple reflections (see Fig. I-1).

In the above figure, the wave R is the sum of waves travelling along 0" OR, 1" 1 1' OR, 2" 2 2' 1 1' OR etc... When the initial wave is a pulse, the reflected wave, which is the sum of several pulses displaced from each other by the time of travel,

$$\frac{1\ 1'0}{V_2} - \frac{LO}{V_1}$$

is changed in shape. If the initial wave is a sinusoidal wave, all waves are sinusoidal, and the resultant is also a sine wave of the same frequency but with a suitable phase shift. In this case, the reflection coefficient is not simply a positive or negative quantity but is a complex number indicating the presence of a phase shift. Also, R is a function of frequency because the same delays which reinforce reflection at one frequency will destroy the reflection at another frequency. This interference phenomena is familiar in the optical context where oil spots on wet pavement show interference colors on reflection.

In conventional seismic processing, it is usually assumed that R is a real number with a positive or negative sign depending on the change of ρV. It is also assumed that it is independent of frequency. This assumption would be satisfactory either if multiple reflections do not occur or if they are taken into account. Because the multiple reflections exist and are not taken into account, a better assumption would be to let R be a function of frequency and also allow it to have phases other than 0 and π only.

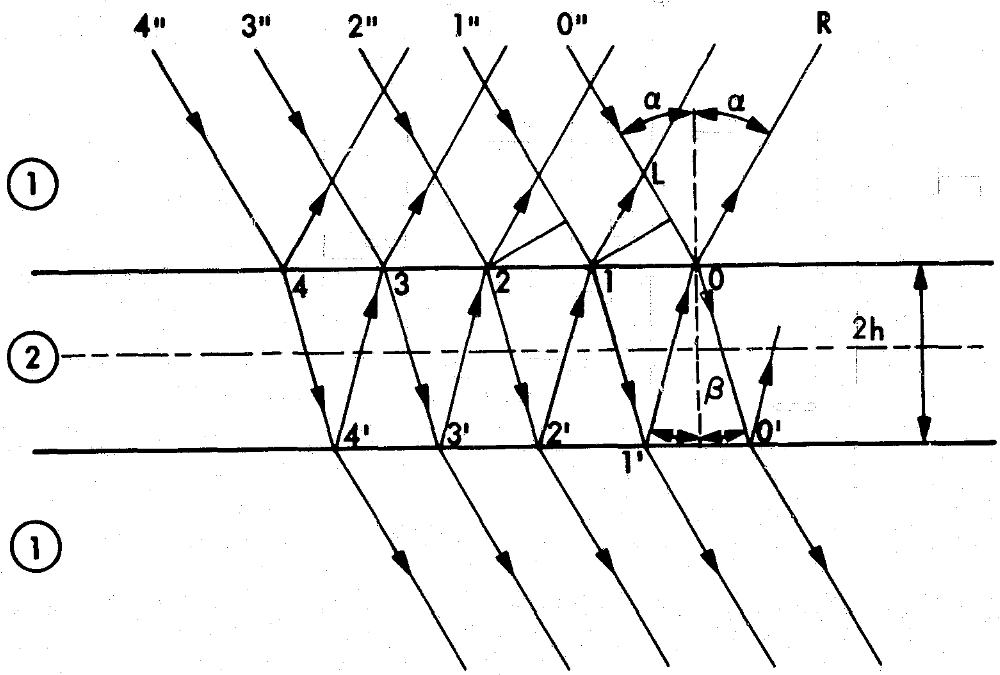


Fig. I-1. Reflected Wave Change due to Multiple Reflections (Ref. I-1)*

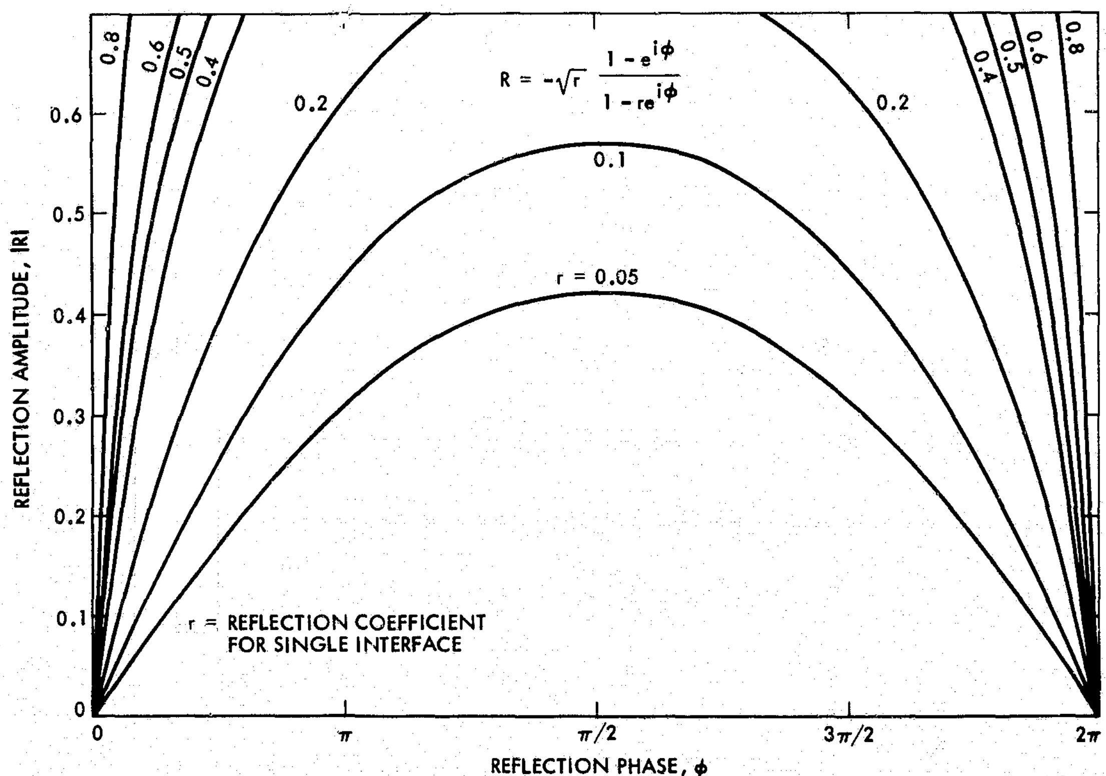


Fig. I-2. Reflection from a thin layer

*References are listed at end of this appendix.

The technique of time-delay spectrometry (TDS) allows one to measure both the amplitude and phase of R at various frequencies and is therefore able to include the phenomena of interference in seismic data processing. Conventional processing of seismic data is not able to interpret the change of shape of the seismic reflections in terms of the interference due to the thin layers. Processing of Vibroseis data by TDS may be expected to improve resolution of thin layers. Note, for example, in Figure I-2, that, when the difference in path length across a layer is near half a wavelength, the amplitude is quite insensitive to path difference, but the phase is very sensitive.

II. METHOD OF SIGNAL PROCESSING BY TIME-DELAY SPECTROMETRY (TDS)(Ref. I-2)

Consider an input frequency-modulated chirp signal with a frequency variation of f_o to f_f, applied at the surface as shown in Figure I-3 and given by

$$S(t) = A_o \cos[wt + \phi(w)] \tag{1}$$

where

$$\left.\begin{aligned} f &= f_o - r(t - t_o)^* \\ r &= (f_o - f_f)/(t_f - t_o) \end{aligned}\right\} \tag{2}$$

and $\phi(w)$ is the initial phase.

The reflected signal R(t) received at the point of origin of the source from the various interfaces, namely the weathered layer and the different underlying geologic strata, can be described by

$$R(t) = \sum_{j=m}^{j=n} A_j(t) \cos[w_j t + \psi_j(t)] \tag{3}$$

where

$$f_j = f_o - r(t - t_j) \tag{4}$$

t_j being the time of arrival of the reflected wave from the j^{th} interface. The indices m and n are such that

$$f_f \leq f_m$$

and (5)

$$f_o \geq f_n$$

* In the following w and f are related by $w = 2\pi f$

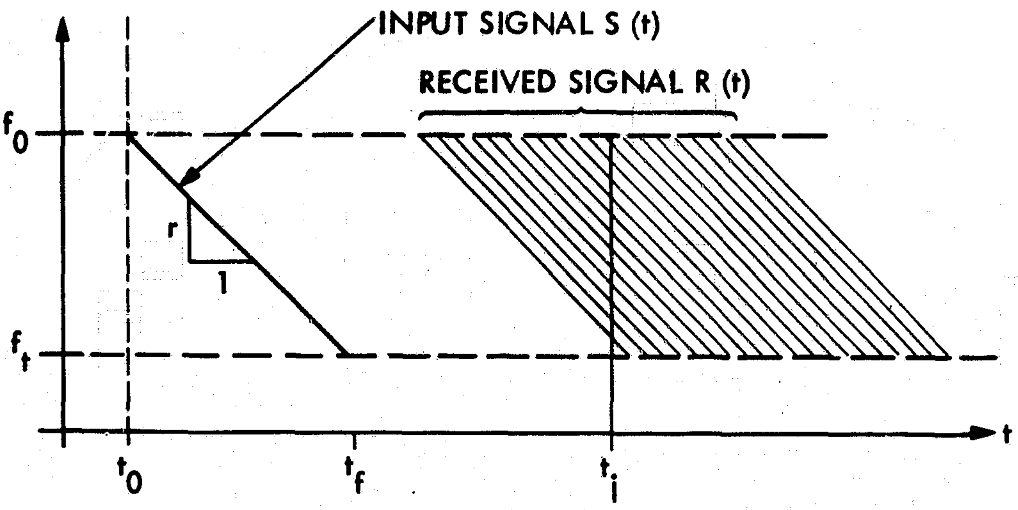


Figure I-3. Chirp Signal and Resulting Signature from Vertical Reflections

Application of time delay spectrometry (TDS) for the processing of the reflected signal R(t) involves the determination of A_j (t) and ψ_j (t) for the j^{th} interface and are obtained as follows.

Consider the heterodyne of the reflected wave R(t) with

$$C_d(t) = A_o \cos[wt + \phi]$$
$$S_d(t) = A_o \sin[wt + \phi] \qquad (6)$$
$$w = f_o - r(t - t_j + T_o)$$

where $C_d(t)$ and $S_d(t)$ are the input signal and its complement respectively having an offset frequency $f_a = rT_o$ with respect to the reflected wave from the j^{th} interface. Denoting the heterodyne of R(t) with $C_d(t)$ and $S_d(t)$ by $F_j(t)$ and $G_j(t)$ respectively one has

$$F_j(t) = R(t)\cdot C_d(t) = \sum_{S=m}^{S=n} \frac{1}{2} A_o A_A \Big\{ \cos[r(T_o + t_S - t_j)t + \psi_S - \phi] + \cos[(w + w_S)t + \psi_S + \phi] \Big\} \qquad (7)$$

and a similar expression for $G_j(t)$.

In the above,

$$t_j \leq t \leq t_f + t_j - t_o.$$

The amplitude $A_j(t)$ and the phase $\psi_j(t)$ are obtained by convolution with a narrow band-pass filter.

Denoting the filtered quantities by $\bar{F}_j$ and $\bar{G}_j$, it can be shown that

$$A_j(t) = \pi\left[\bar{F}_j^{\,2}(t) + \bar{G}_j^{\,2}(t)\right]^{1/2}/(A_s \cdot \Delta w) + \varepsilon_1(\Delta w) \tag{8}$$

and

$$\phi_j^s = \phi - \psi_j(t) = w_a t + \tan^{-1}[G_j\bar{(t)}/F_j\bar{(t)}] + \varepsilon_2(\Delta w) \tag{9}$$

where

$$t_j \leq t \leq t_j + t_f - t_o$$

$\varepsilon_1(\Delta w)$, $\varepsilon_2(\Delta w)$ are error terms which can be bounded and made sufficiently small by choosing a proper filter width Δf.

Since the input signal is a chirp signal (figure I-1) the expressions (8) and (9) for the amplitude and phase reflected from the j^{th} interface at a given instant of time t also express the amplitude and phase as a function of frequency f where f=rt and such that $f_f \leq f \leq f_o$.

Thus for a given arrival time t_j on the reflected wave, one can find the amplitude $A_j(f)$ and phase shift ϕ_j^s (f) as functions of the frequency f within the band of the chirp signal. This procedure can be repeated for various values of t_j in the significant part of the reflected wave and plots of amplitude and phase as a function of the arrival time t_j for a given frequency f within the chirp signal can be obtained. Further the procedure given above can be applied for reflected waves obtained at various horizontal locations 0, 1, 2, 3 along the line of the geophones recording the signals. By assigning gradation of colours to the amplitudes and phase changes depending on their strength a cross sectional image of the seismic section can be obtained for any frequency chosen within the frequency band of the chirp signal.

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APPENDIX J

TOMOGRAPHIC METHOD FOR DOWN-HOLE SEISMIC SURVEYS

I. GENERAL

Tomography is a method of image reconstruction from projections of the object from various directions. The principle of tomography was established by an Austrian mathematician, J. Radon, in 1917; he proved that a two-dimensional or three-dimensional object can be reconstructed uniquely from the infinite set of all its projections. Although the principle of tomography was established in the early part of this century, the full exploitation of the tomographic reconstruction technique had to await the arrival of modern computers since the computation required for each three-dimensional reconstruction is large. Methods have now been developed to simplify the procedure and reduce the amount of computation to make tomography a profitable tool. For instance, reconstruction of a three-dimensional image can be reduced to that of reconstructing a two-dimensional cross section from its one-dimensional projections, and the three-dimensional image can be obtained by stacking a sequence of two-dimensional cross sections. The number of projections themselves can be minimized although the resolution of the resulting image will be corresponding reduced. Tomography has been successfully applied to recover even such complex features of the human face as shown in the illustrations of Ref. J-1*. Also tomography is being increasingly used in medical diagnosis using X-ray projections for scanning the human brain.

Here it is suggested that tomography can be successfully applied to petroleum exploration especially for mapping cross-section of geological strata between two boreholes. The application of tomography coupled with down-hole acoustic techniques to obtain details of geology for identifying petroleum reservoirs is briefly outlined in the following:

Consider the mapping of the cross-section between two boreholes indicated in Figure 3-B-1 in Vol. 1. Signals transmitted through the cross-section from a series of shots A, B, etc., in one borehole can be obtained from phones located at various positions on the other borehole and on the surface. The ray paths of only the transmitted signals from two shot point locations A and B in one borehole to various phone locations are shown in the figure. Here straight ray paths within each bed are assumed for the first approximation, which can be improved by iteration.

In general, the complex record of a phone G_1 or G_2 in the borehole or on the surface due to a shot at A will be a composite of the transmitted wave along AG_1 or AG_2 together with other waves arriving at the phones from a variety of possible ray paths. However, by the usual methods of refraction seismography the ray path of the transmitted wave can be identified, and hence the records obtained from consecutive phones can be processed to identify the transmitted waves along AG_1 or AG_2.

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*References are listed at the end of this appendix.

The method of processing to identify the transmitted wave along an assumed ray path is as follows:

Consider the transmitted wave arriving at the phone location G_i at angle θ and at neighboring phones equally spaced on either side of G_i (Figure J-1). If the phones are closely spaced, the angles of arrival at neighboring phones will be approximately θ. Assuming that the phones are equally spaced at a distance d around G_i, the time delay of arrival at consecutive phones of the transmitted wave under consideration can be determined and is given by

$$\Delta t = d \sin \theta / V_{eff} \tag{1}$$

where V_{eff} is the effective wave velocity. Thus, if the arrival time of the transmitted wave at a phone location G_i is t_o , then the phones at G_{-1}, G_{-2}, . . . G_{-n} will receive the transmitted wave earlier at time $t_o - \Delta t$, $t_o - 2\Delta t$, . . . $t_o - n\Delta t$ and the phones at G_1, G_2, . . . G_n will receive the wave at $t_o + \Delta t$, $t_o + 2\Delta t$, . . . $t_o + n\Delta t$ respectively. Hence the transmitted wave at the phone location G_i can be identified by stacking the records of phones at G_{-1}, G_{-2}, . . . G_{-n} with a time delay of Δt, $2\Delta t$, . . . $n\Delta t$ with respect to record of phone G_i and also stacking the records of phones at G_1, G_2, . . . G_n with a time advance of Δt, $2\Delta t$, . . . $n\Delta t$ with respect to the record at G_i. Thus the arrival time t_o and the amplitude of the transmitted wave under consideration at G_i can be determined. It is of interest to mention here that the above method of processing will single out and enhance wave arriving at a phone in a particular direction, and the waves arriving at the phone from other directions will cancel. Further the method of processing described above can be generalized to recover waves arriving at a phone from various directions and is applicable even to the case when two waves arrive at a phone simultaneously. Further this method of processing is applicable in general and is not neccessarily confined to the down-hole acoustic technique.

Thus from the preceeding discussion, it follows that the arrival times and amplitudes of the transmitted waves along the various ray paths AG_1, AG_2, . . . AG_j to phone locations G_1, G_2, . . . G_j due to the shot at A can be determined. This procedure can be repeated for various shot locations A, B, C, etc. Similar results can be obtained for shots in the borehole on the right in Figure 3-B-2 of Vol. 1 with phones located in the other borehole and on the surface. From these results and with the method of processing suggested here to identify the transmitted wave along a ray path, it is possible to reconstruct, with the aid of tomographic principles, the details of the geology between the two boreholes.

For the purpose of demonstrating the method of tomographic reconstruction, consider the arrival times of the transmitted wave at various phone locations due to the various shots in the two boreholes. The two-dimensional cross sections between the two boreholes are divided into a number of rectangular regions and their coordinates with respect to a cartesian coordinate system X Z can be identified (Figure 3-B-2). Each rectangular region or pixel is intercepted by a number of transmitted wave ray paths from various shot points to phone locations. For purposes of illustration, three transmitted wave ray paths from

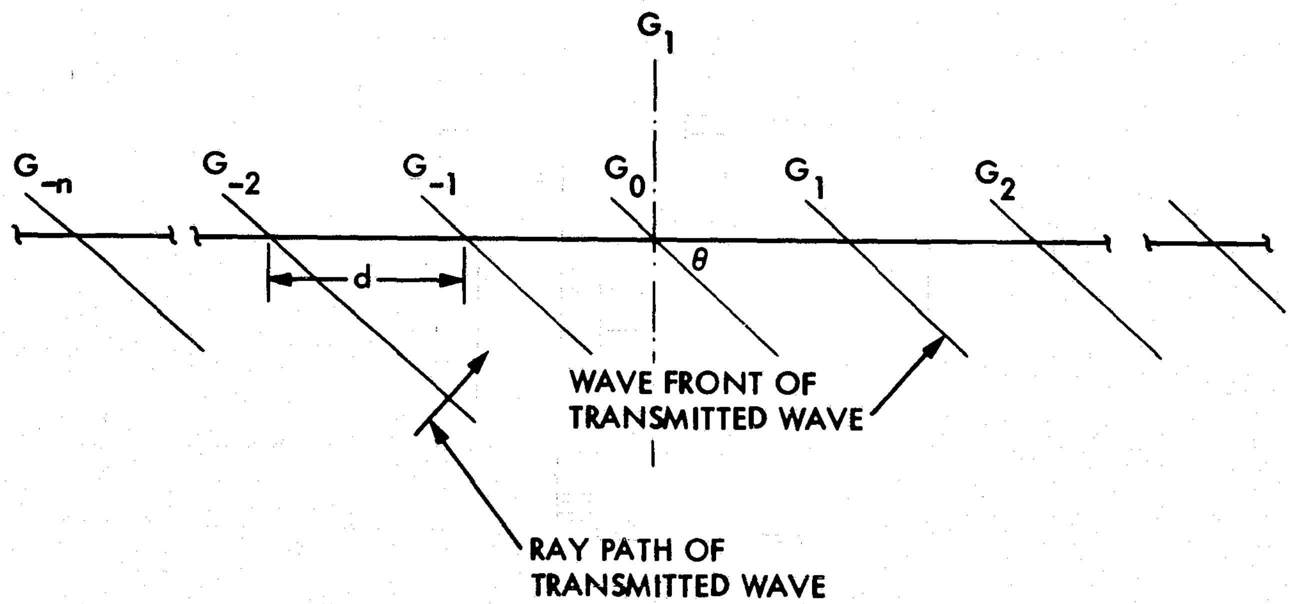

Figure J-1. Directional Processing of Signals to Identify Transmitted Waves

shot points A, B, and C to the phone locations G_p, G_q, G_r respectively intercepting the pixel I J are shown in the figure. If the times of arrival of the transmitted wave from shot points A, B, and C to the phones G_p, G_q, G_r are given by t_{ap}, t_{bq}, and t_{cr}, one can write

$$t_{ap} = \sum_{ij} t_{ij} \cdot \omega_{ijap} \tag{2}$$

$$t_{ij} = \left(\frac{\Delta X \cdot \Delta Z}{V_{ij}^2} \right)^{1/2} \quad ; \; \omega_{ijap} = \left(\frac{\ell_{ijap}^2}{\Delta X \cdot \Delta Z} \right)^{1/2} \tag{3}$$

where ΔX pixel length in X direction

ΔZ pixel length in Z direction

V_{ij} transmission velocity in pixel I J

ℓ_{ijap} length of intercept with pixel I J of the transmitted ray from shot point A to geophone G_p

and the summation i j is carried over all pixels intercepted by the transmitted ray path. Similarly one can write

$$t_{bq} = \sum_{ij} t_{ij} \cdot \omega_{ijbq} \tag{4}$$

$$t_{cr} = \sum_{ij} t_{ij} \cdot \omega_{ijcr} \tag{5}$$

Similar equations can be written for all the pixels in the cross-section between the boreholes and for the transmitted ray paths between the various shot points and geophones. Solution of these equations for all t_{ij} will yield the "time picture" of the geological cross-section between the two boreholes.

Various methods are currently available for obtaining the solutions of the stated simultaneous equations (Ref. J-2). The algebraic reconstruction technique (Ref. J-3) among them seems to be particularly suited to the present problem since the storage requirements for the computer will be minimized and this method also has a relatively rapid rate of convergence.

One variant of the algebraic reconstruction technique is the following iteration procedure. In equation (2), t_{ij} represents a time delay depending on the velocity of transmission of the material in pixel I J, and ω_{ijap} can be considered as a weighting factor. Equation (2) expresses the fact that the weighted sum of the time delays of all the pixels intercepted by the ray AG_p is equal to the arrival time of the transmitted ray at phone G_p. Hence, at any step in the iteration, the weighted sum of the time delays of all the pixels intercepted by a given ray path, say AG_p, can be compared with the arrival time t_{ap}. In general, the two quantities will differ. If

$$\varepsilon_{ap}^{n} = \left[t_{ap} - \mathop{}_{ij} t_{ij}^{n} \cdot \omega_{ijap} \right]; \text{ and } \varepsilon_{ap}^{n} > \varepsilon_o \tag{6}$$

where ε_o is a predetermined error bound and ε_{ap}^{n} is the error in the ray path AG_p on the n^{th} iteration, then one can take

$$t_{k\ell}^{n+1} = t_{k\ell}^{n} + \varepsilon_{ap}^{n} \quad \frac{\omega_{k\ell ap}}{\sum_{ij} \omega_{ijap}}$$

This procedure can be repeated for all the ray paths until $\varepsilon_{ap}^{n} < \varepsilon_{o}$.

A similar procedure for the amplitudes of the transitted waves can be followed, and one can obtain an "amplitude picture" of the same cross-section. The time (velocity) and amplitude (attenuation) pictures so obtained can be used in detecting and locating the stratigraphy and structure.

The procedure described above is strictly applicable to straight-line transmitted ray paths, and in this sense, it will be the first approximation to the actual ray paths in the region under study. To improve the above procedure iteratively to account for curved ray paths, one can effectively utilize the down-hole velocity logs obtained for the boreholes together with those by refraction seismography analysis. From the velocity variation with depth, one can determine the curved ray paths between the shot point and the phones. These curved ray paths determine the intercepted pixels and the method of processing described above for straight ray paths can now be applied.

II. ADVANTAGES OF SEISMIC TOMOGRAPHY

It is of interest to note some of the advantages of tomographic mapping utilizing borehole to borehole and borehole-to-surface acoustic techniques. One of the major problem in the current reflection seismic processing on land is the presence of near-surface inhomogeneity of the weathered layer, leading to the ambiguous "static corrections." This problem largely disappears in seismic tomography between two boreholes as described here. With one borehole, a single travel of the waves through the weathered layer leads to less of a problem of static corrections than the double pass through the weathered layer required in current seismic-reflection processing. With down-hole sources and phones, poorly transmitting beds overlying those of interest do not matter, and high dips can be handled.

It is likely that the geological regions in which reflection seismics are generally difficult to interpret are more easily amenable to seismic tomography. For instance, a common characteristic of regions of growth structure, such as salt domes, is overhang. A major problem in exploration is to be able to see through the salt overhangs to detect sediments and traps below them. The current seismic-reflection processing frequently cannot detect more closely than a few hundred feet of the overhang, but several hundred feet of reservoir in a trap of this type (with sands of 100 feet thick) can contain a major quantity of oil that can potentially be missed. At present, it is common practice to drill as closely as one can and then deviate the hole toward the dome until salt is penetrated. In these circumstances, seismic tomography is particularly advantageous and can potentially reduce the expense involved in "wildcat" drilling.

If two or more boreholes are available within distances of a km or so of each, the transmission paths to determine geology at depth will be much shorter than the 2-way path from the surface and back. This should permit the use of higher frequencies and hence improved resolution.

Since the processing of time and amplitude pictures utilizing tomography as described here is done for "depth-sections," the complex process of "migration" required in conventional processing to convert "time-section" to "depth-section" is entirely eliminated. Further, the initial tomographic processing itself can be done on a coarse grid and thus the expense involved in processing minimized. If the initial processing indicates the geological region to be of interest, the procedure can be refined using a smaller mesh size, and the region under study can be mapped in more detail. Thus, the degree of tomographic processing can be varied depending upon the initial results.

III. EQUIPMENT AND DATA-PROCESSING REQUIREMENTS

Various types of seismic sources may be suitable for this technique. For fixed source positions, the oscillation-free implosion source (glass sphere containing air at 1 atmosphere) proposed above (Vol. 1 Section III-A) seems particularly advantageous. For fixed down-hole phones, either geophones clamped to the walls or hydrophones could be used. Clamping may be needed in any case so that the cable can be structured to reduce wave transmission along it.

The resolution of the method can be significantly improved by moving the sources and phones during operation so that records are obtained for a great many combinations of source position and phone position. A repetitively pulsed source (perhaps a sparker) could be traversed along one borehole. Possibly the string of hydrophones could at the same time be oscillated up and down in the other borehole over a distance equal to the spacing between phones. This might be more difficult, however, since motion of the phones against the walls would generate noise.

For the directional processing required in the present method, and to obtain better resolution, it is necessary to use a single phone or several phones at each depth (or position on the surface), rather than a group spread out over some distance.

To gain an understanding of the amount of data acquisition involved in the proposed bore-hole technique and to obtain a comparison with data acquired in existing systems, an estimate is made for an assumed borehole geometry:

<u>Assumptions</u>:

Depth of borehole	~1 km
Spacing between boreholes	~1 km
Number of channels used for recording	96
Frequency resolution	100 Hz
Average velocity of the geological medium	3 km/sec

Analysis of data handling involved:

Wave length for a frequency of 100 Hz: 3000/100 = 30 m. Assuming 3 phones are placed within the wavelength to obtain the required resolution and for directional processing to identify the received wave, the phone spacing is 10 m.

Hence, 96 phones or 96 small groups will roughly cover the depth of the borehole. Another set of 96 will cover the surface between the two bore holes. Thus one shot at a given location in one borehole is sufficient to record signals in the other borehole and on the surface. Assuming the location of shots to be at intervals of 50 m in the borehole, 20 shots will be required over the depth of the borehole. Since each phone data is being recorded separately, the total number of records will be 3840. Thus the amount of data handling is somewhat increased, but the refined method of data processing suggested here and the results obtained therefrom should more than offset the requirements of increased data. Further, the ultimate cost-effective comparison must be made with respect to decisions in regard to "wildcat" drilling, which are difficult to analyze (see Vol. 1, Section 3-G).

IV. COST ESTIMATE

When two boreholes are available, the cost of tomographic reconstruction using 20 shots will be roughly $10,000 for setting up, the $10,000 for data acquisition, and $400 for data processing. If tomography is done in addition to other acoustic logs, the setup cost may be lower.

V. DEVELOPMENT SEQUENCE

A suitable first step in development of the technique would be computer simulation. Received signals would be simulated by modifying an existing program that generates "synthetic seismograms."

A possible next step would be an experimental small-scale model. This experimental facility could also be utilized for developing the acoustics backscatter log discussed separately. High-frequency sound waves can replace seismic waves and all dimensions of the experimental facility can be scaled down by a large factor. Although such scaling is not strictly applicable for layered and inhomogeneous geologic media, for the purpose of demonstrating the tomographic reconstruction technique economically high-frequency sound waves and a suitable medium can be used. The data can be obtained by using electromagnetic transducers to apply force at selected points and the signal received by piezoelectric transducers. The method of tomographic reconstruction can be applied to recover known objects in the medium between the experimentally simulated boreholes.

The computer simulation and the experimental model should help in evaluating the method and determining suitable parameters for field use. A following step would be a field test using equipment adapted for the purpose. Finally, operational equipment and procedures would be developed and tested.

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J-3. R. Gordon, "A Tutorial on ART," IEEE Transactions on Nuclear Science, Vol. NS-21, 78-93, June 1974.

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APPENDIX K

DOWN-HOLE FRACTURE DETECTION

I. EXISTING INSTRUMENTS FOR FRACTURE DETECTION

At present, the following tools give an indication of horizontal fractures. Description of these instruments and methods are available in greater detail in the book edited by G. V. Chilingar et al. (Ref. K-1)*. In general, differential gravity stresses cause vertical fractures also, and these methods are not efficient for detecting vertical fractures.

A. ACOUSTIC AMPLITUDE MICROSEISMOGRAPHY

This sonic device is similar to the velocity-logging tool. It generates sound pulses which travel from the source to the receiver located a few feet below. The waves go through various paths in the bore-hole mud and through the adjoining formations. The intensity modulated display of the amplitude of the received signal vs the time of travel indicates the presence of fractures as regions of low signal (Figure K-1). The same tool when used in a cased hole is a cement bond log and shows a good bond of the casing to the formation by the absence of a strong signal through the casing. In addition, the multiple reflections and refractions due to fractures will distort and dampen the regular pattern of the intensity display. Display of the amplitude at a particular travel time is plotted as an additional log, and a fracture index is associated with the amplitude (Figure K-1). The scale is based on the observation that a single fracture oriented normal to the sound ray decreases the transmitted amplitude to about 0.77 times the incident value. A given amplitude A can therefore be associated with the equivalent number of fractures N by the formula $(0.77)^N = A$.

The above log is not strictly quantitative because of many complexities. As indicated by De Witte (Ref. K-2), (1) fractures are not plane and have many points of solid-to-solid contact, (2) most fractures are not normal to the bore-hole axis and in fact are commonly in the vertical direction, (3) vertical fractures are parallel to sound rays and do not influence them, (4) variations in lithology produce large amplitude variations also, and (5) variation of amplitude also results from the noncentralization of the tool in the borehole. Item (5) can be solved by the use of centralizers or by repeat runs.

B. BORE-HOLE TELEVIEWER LOG

This tool is useful in seeing wall discontinuities, formation dip and bore-hole fractures (Ref. K-1). Pulses of ultrasound are beamed to the walls of the borehole and are received as reflections while the tool rotates at three revolutions per second and descends in the borehole at a low speed, 5 cm/second. An intensity modulated display of the inner surface of the borehole is obtained.

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*References are listed at the end of this appendix.

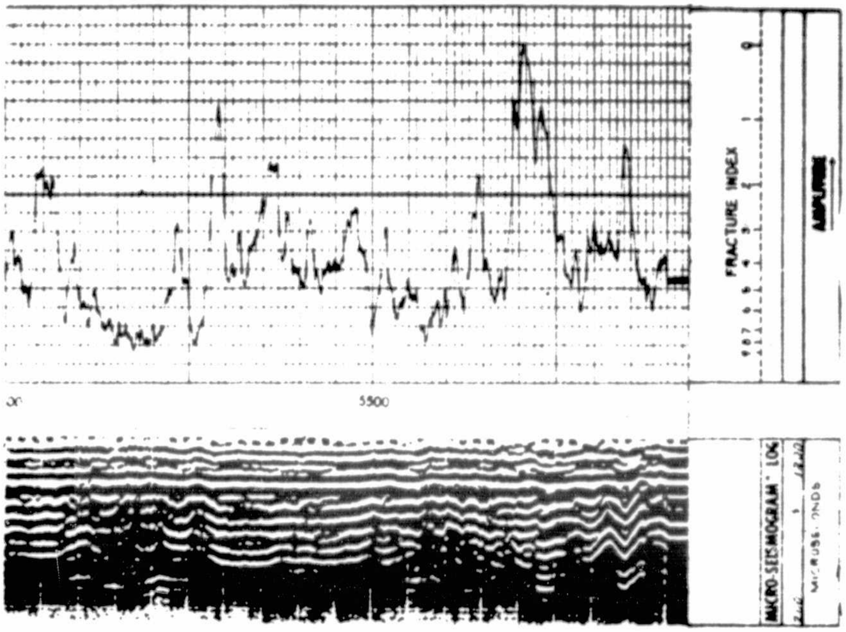

Figure K-1. Microseismograph Log and Fracture Index (Ref. K-1)

Figure K-1. Microseismograph Log and Fracture Index

It would be useful if fractures some distance away from the bore-hole surface could be obtained because the drilling operation could have disturbed the original distribution. The bore-hole televiewer gives only a surface indication which may be quite different from the distribution of fractures some distance away from the borehole.

II. MECHANISM OF SOUND REFLECTION

When sound waves are incident on the boundary between two media of different acoustic impedances, a part of the energy is reflected, and the remaining is transmitted. In general, both dilatational and shear waves are produced on reflection. It is also clear that if two pieces of the same medium are in firm contact, there will be no reflection at the interface. If, however, there is a small gap between the two pieces which is occupied by another medium, such as oil, reflections occur. The magnitude of reflection depends on the impedances of the different media, size of the gap, and wavelength of the sound waves. This phenomenon of interference colors is a matter of common observation and is seen on oil spots on a wet pavement in the optical context. In this case too, the reflection vanishes when the gap becomes much smaller than a wavelength, whatever the various impedances may be.

Another cause of reflection is the anisotropy of the materials. For example, when a liquid metal solidifies, grains develop in which the elastic axes are oriented in different directions. Even though the density of the material is uniform, the grains scatter ultrasound in this case because of acoustic impedance changes due to different elasticities.

Yet another cause of a mismatch of acoustic impedances can arise in the medium because of the nonlinearity of the stress-strain curve. The two sides of the medium on either side of the fracture may be stressed to different levels because only the normal stresses need be continuous across the interface. If the stresses are large enough, the two sides will have different Young's moduli which are the local slopes of the stress-strain curves in the nonlinear regions. This situation is possible in rocks with fractures because the very presence of the fractures indicates that the rocks were subjected to stresses high enough to crack them.

The magnitude of reflection depends on many parameters. In what follows analysis of the backscattering from fractured rock will be done by considering the fractures to divide the rock into a number of inhomogenities in the manner of grains. If the wavelength is larger than the size of the inhomogenieties, the phenomenon would resemble the corresponding one of scattering of ultrasound in metals.

III. THE PULSE-ECHO METHOD OF TESTING WITH ULTRASONIC WAVES

The pulse-echo method of nondestructive testing is well-established. This information is available in many books. The book by Krautkramer (Ref. K-4) is a good source book of various techniques. Some of this information is presented here to indicate how it is applicable to the bore-hole problem.

The principle of the pulse echo method is illustrated by Figure K-2.

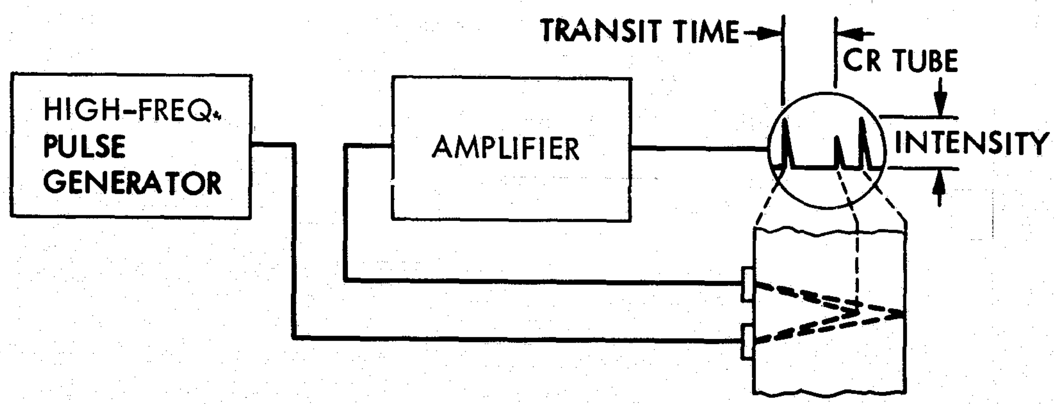

Figure K-2. Principle of Pulse-Echo Method [After: Krautkramer (Ref. K-3)]

In a practical case, the transmitter and receiver can be the same device. The pulse height and the transit time allow a determination of the size of a single crack and its location.

Figure K-3 shows schematically the traces on the viewing screen for various cases involving different kinds of flaws.

In the figure, a transducer in the borehole transmits away from the borehole to the right and receives the reflected pulses. (a) shows a small crack in the sound beam; (b) two small flaws; (c) large flaw in the found beam which masks other small flaws further out; (d) an oblique flaw which doesn't back scatter and is, therefore, not seen; and (e) strong attenuation of sound beam due to scattering with no echo from any flaws except "grass" due to scattering by inhomogeneities. The last case is the one of interest because the "grass" indicates how broken and cracked the medium is around the borehole.

IV. CONSTRUCTION AND MODE OF OPERATION OF A PULSE-ECHO INSTRUMENT

The technology of nondestructive testing using ultrasound is well known. The electronic circuits are commercially available. Operation is possible with a separate source and receiver as well as with two being the same device. For display, it is usual to rectify the received and transmitted signals. The circuits for generating high-frequency pulses and the amplifier for the received pulses are well known and are described in detail in Krautkramer's book (Ref. K-4). Frequency of operation is selected on the basis of the needed resolution and the amount of attenuation to be expected. For the borehole application, the frequency of operation is chosen depending on the size of inhomogeneities of interest so that a useful echo can be observed a few meters away from the transducer.

A. COUPLING

The best coupling of the probe to the bore-hole wall is one of direct contact for two reasons. If there is a gap between the face of the transmitter and the bore-hole wall, sound waves are strongly reflected at the wall because drilling mud and the rock have very different impedances. There is a great loss of energy which could otherwise have been transmitted into the rock. In addition, the echo pulses running back and forth produce a large number of pulses which masks the reverberation due to cracks. The gap should be very small compared to the wavelength of sound in the drilling mud for good transmission of the pulse into the medium.

A value of gap = $\lambda/40$ is good. If transmission loss is tolerated, the gap can be as much as $\lambda/4$. With a gap of $\lambda/4$, there are no interfering echos. When the gap exceeds a wavelength, the interfering echos are excessive.

Introduction of layers of absorbing material in front of the transducer helps in attenuating the echos due to the gap. These can be layers of resin or teflon or sprayed-on plastic layers on the face of the transducer. With this treatment, firm contract to the wall is not needed.

Another possibility is to separate the transmitter and receiver. In this case, reverberation due to the gap near the transmitter is not directly picked up by the receiver but the pulse is broadened. This may not be a serious effect.

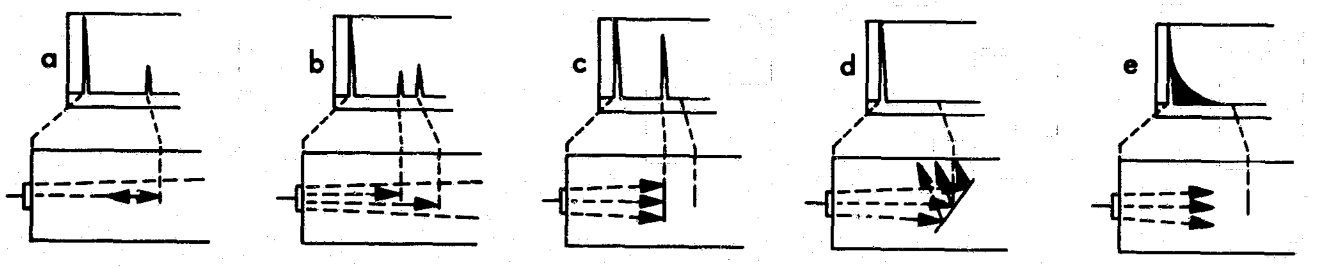

Figure K-3. Various Cases of Flaws [After: Krautkramer (Ref. K-3)]

When direct contact with the wall is not needed, operation when the transmitter and receiver are moving becomes possible. This advantage may lead to choice of this mode even though the echos are weaker and the pulses broader than in the case of firm contact.

A modification of the acoustic logging intended to increase its sensitivity to fractures has been offered on an experimental basis by one company. This takes advantage of the fact that a fracture may constitute a greater discontinuity to shear waves than to longitudinal waves. To do this, the receiver is placed in the borehole at a 90 angle to the transmitter. This modification could probably be of value in the backscatter log method; it would require direct contact (clamping) of the transmitter and receiver to the wall.

B. ANALYSIS AND RESULTS

The backscatter analysis is outlined in Appendix L. Scattering by randomly oriented fractures (Figure K-4) is considered to resemble the phenomena of volume reverberation. The parameters involved are the scattering cross section and number of scatterers per unit volume, N. The mean distance between cracks determines N. When the wavelength of the sound wave is greater than the mean distance between cracks, the shape of the scattering object is unimportant. Equation (3) of Appendix L gives the echo strength of the back scatter as a function of , N and other parameters. The value of (N) can be determined by a measurement of G^2 defined in that equation, (3). The parameter (N) can be related to the permeability empirically by a set of controlled laboratory model or field experiments which yield a set of calibration curves for determining permeability as a function of porosity and (N). The operating frequency permeability as a function of porosity and (σN). The operating frequency of the logging tool can be varied to maximize the echo on the basis of the average sound velocity of the medium and the expected mean distance between fractures, which in some reservoirs is of the order of 1 cm (Ref. K-2). The frequency of sound corresponding to a velocity of ~3 km/sec and of λ = 1 cm is 300 kHz. To seek fractures spaced 10 cm apart with this sonic velocity, the appropriate frequency would be about 30 kHz. Accordingly, measurements should be made at several frequencies. Further optimization is considered in Appendix L.

By using several receivers spaced vertically with respect to the transmitter, information on the direction of the fractures with respect to the bore-hole axis can be obtained because the scattering amplitude will vary with direction, relative to the plane of the fractures. By clamping the transmitter at various positions around the wall of the hole, information can be obtained on the direction of the fractures within the plane perpendicular to the borehole.

C. DATA PROCESSING, DISPLAY, AND INTERPRETATION

The data could be displayed simply as a cathode-ray pattern. To provide more quantitative output and permit calibration corrections to be incorporated, a limited amount of analog processing would be useful. Digital processing is not contemplated.

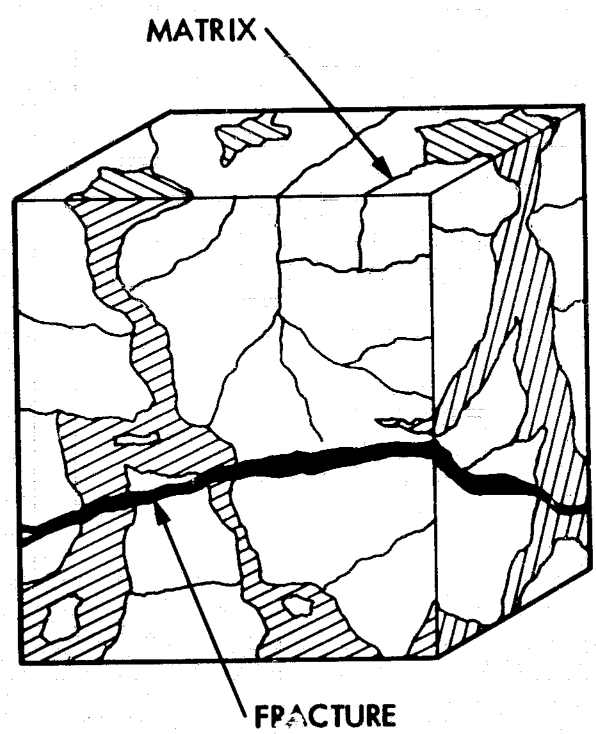

Figure K-4. Randomly Oriented Fractures Considered as Inhomogeneities (Ref. K-1)

Interpretation would be in terms of a frequency distribution of fracture spacings and their number density. Permeability information should be derivable.

V. RECOMMENDATIONS

A program to evaluate and develop a well-log of this type is recommended. Design would be based on that of devices used in nondestructive testing of materials. The electronics design and choice of piezoelectric transducers are straightforward. Most of these are commercially available.

An important early step should be a laboratory simulation of the borehole surrounded by a suitable medium. This would be used to verify the concepts, to establish the technique of determining the cross-sectional parameter σN, and to check the backscatter model discussed in Appendix L. The model would be approximately full scale with a vertical hole a few inches in diameter in a cylindrical tank a few meters across.

A subsequent step would involve field testing of a down-hole prototype. If the model and field tests were promising, design and construction of an operational version of the device would follow.

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APPENDIX L

BACKSCATTER MODEL FOR RANDOMLY ORIENTED FRACTURES

I. GENERAL

In this appendix, the backscatter model will be developed and some estimates made using data on polycrystalline metals. The intensity of sound scattered from a region containing inhomogeneities can be assumed to be the sum of the intensities scattered from each. For example, a bubble can be the single scatterer. At a distance r from the bubble, the scattered intensity would be $\sigma_s J_o/4\pi r^2$ where σ_s is the scattering cross section of the bubble and J_o = incident intensity. Omnidirectional scattering has been assumed in the above expression. But the scattered sound is attenuated by other scatterers in the medium. Therefore, the scattered radiation at a distance r_1 from a volume dV containing ndV scatterers is given by

$$dJ_s = \left(\frac{ndV\sigma_s}{4\pi r_1 2}\right)\left(J \exp - \sigma_e \int_0^{r_1} n(r)\ dr\right) \tag{1}$$

σ_e is the total cross section corresponding to the sound energy removed from the scattered sound and is equal to $\sigma_s + \sigma_a$ where σ_a is the sound absorption cross section. For inhomogeneities which scatter only, with no absorption, $\sigma_e = \sigma_s$. The formula for backscatter will be derived next.

II. VOLUME REVERBERATION

We consider the backscatter from inhomogeneities in the medium received at the transmitter (which is also the receiver) after a signal pulse of duration τ is projected into the medium (see Figure L-1). The signal arriving at $r = 0$ at time t occupies a radial extent $C\tau/2$, as can be seen from the rt diagram. As t increases, the echo comes from further and further away.

In the following discussion, V is the receiver output in volts for a plane wave of unit intensity incident normally on the transducer (i.e., sound ray along the acoustic axis). The quantity σ is the cross section of an inhomogeneity, and σN expresses the cross section of N scatterers in unit volume. The formula has an inverse square dependence on r. The incident intensity falls off as $1/_r 2$ and so does the echo returned. In addition, there is an attenuation in the medium. The attenuation due to a round trip of distance 2r is $e^{-\alpha 2r}$ where α is the attenuation coefficient and $b(\theta,\phi)$ and $b'(\theta,\phi)$ are the directivity ratios in the direction (θ,ϕ) of the transmitter and receiver, respectively. They can be the same if the transmitter and receiver are the same.

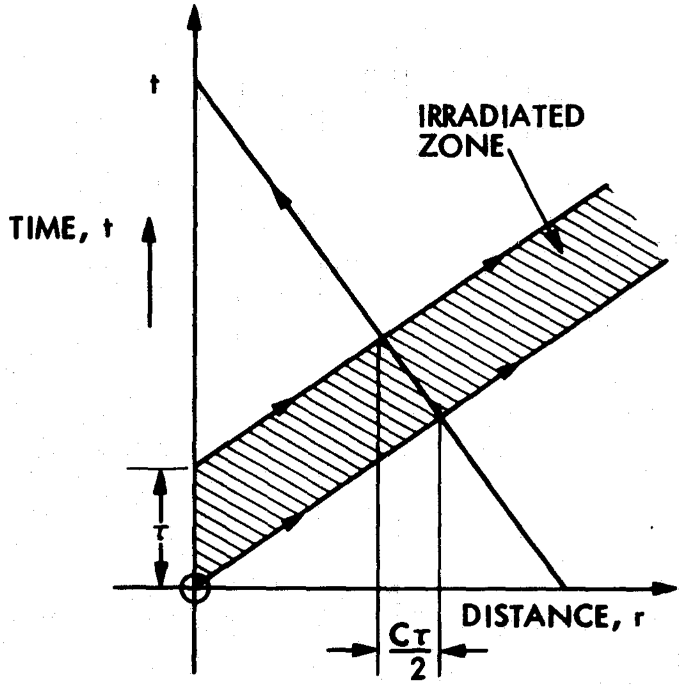

Fig. L-1. Scattering From Inhomogeneities in a Medium

The voltage $\overline{G}$ due to the echo at time t is given by

$$\overline{G}^2(t) = \left(\frac{C\tau}{2}\right) IV^2 \left(\frac{\sigma N}{r^2}\right)\left(e^{-2\alpha r}\right) \left(\frac{1}{4\pi} \int_0^{4\pi} b(\theta,\phi)\, b'\,(\theta,\phi)\, d\Omega\right) \tag{2}$$

The quantity I = radiated power in watts

and V^2 = (voltage output)^2/(received power/area)

If the transmitter and receiver are the same, the input voltage needed to produce the radiated power is given by $\overline{V}_{in}^2 = V^2 I/A$ where A is the area of the transducer,

because
$$\frac{\overline{V}_{in}^2}{\overline{G}^2} = \frac{I}{I_{rec}} = \frac{I\ V^2}{A\ \overline{G}^2}$$

Then
$$\frac{\overline{G}^2}{\overline{V}_{in}^2} = \left(\frac{C\ \tau\ \sigma N}{2}\right) \left(\frac{A}{r^2}\right)\left(e^{-2\alpha r}\right) \left(\frac{1}{4\pi} \int_0^{4\pi} b\ b'\ d\Omega\right) \tag{3}$$

In this equation, each quantity in parenthesis is nondimensional. In decibels,

$$R(t) = \left(10 \log \frac{\overline{G}^2(t)}{\overline{V}^2_{in}}\right) = 10\left(\log \frac{C\tau\sigma N}{2}\right)$$

$$+ 10\left(\log \frac{A}{r^2}\right) \tag{4}$$

$$- 20\left(\log_{10} e\right) \alpha r + J_v$$

where J_v is the volume reverberation index. This quantity

$$J_v = 10\left(\log \frac{1}{4\pi} \int_0^{4\pi} b(\theta,\phi)\ b'(\theta,)\ d\Omega\right) \tag{5}$$

will be zero for an omnidirectional transducer where $b = b' = 1$. Therefore, a directional transducer discriminates against volume reverberation by the quantity J_v which is negative because

$$\int_0^{4\pi} b\ b'\ d\Omega < 4\pi$$

The σ and N are to be estimated in the region near the boreholes by a suitable choice of transmitter, receiver, and frequency of operation.

The technology of nondestructive testing applies to the region near the borehole. Usually the ultrasonic transmitter, which is also the receiver, has a voltage of 100 to 1000 volts and the echos returned from flaws in materials are much smaller, in the neighborhood of 1 mV to 1 volt. The echos are amplified by a factor of 10^5 for display on an oscilloscope screen. The ratio of echo return to transmitter voltage is of order 10^{-3} to 10^{-4}. In other words, the strength of the echos can be measured satisfactorily when they are 60 to 80 dB lower than the strength of the transmitted pulses. The quantity R(t) is in the region of -60 to -80 dB. Define $1/N = T$ = volume of the inhomogeneity which scatters sound (see Figure L-2). Then,

$$\sigma\left(\frac{C\tau}{2}\right) N = \left(\frac{C\tau}{2}\right)\left(\frac{\sigma}{T}\right)$$

is the equivalent number of scatterers along a ray in the insonified region. This number can be different from the actual number of inhomogeneities along a ray because σ may be very different from the geometric cross section.

The length $C\tau/2$ will contain a few waves of ultrasound. It is advantageous to retain only the variable quantities on the left hand side of the equation. Therefore,

$$\left[R(t) - 10\left(\log \frac{C\tau}{2\lambda}\right) - J_v\right] = S(t)$$

$$S(t) = 10 \log\left(\frac{\sigma\lambda}{T}\right) + 10\left(\log \frac{A}{r^2}\right) - 20\ \alpha r\left(\log e\right) \qquad (6)$$

Here R(t) -60 to -80 dB and

$$-10\left(\log \frac{C\tau}{2\lambda}\right) \sim -6 \text{ dB for } C\tau = 8\lambda.$$

J_v = 0 at low frequencies and decreases at higher frequencies. Data on the attenuation in various materials are known in the form of dB/μsec vs. frequency with the inhomogeneity as a parameter (Ref. L-1*). These data can be plotted in the form of

$$\frac{\alpha' T^{1/3}}{C} \text{ vs } \frac{fT^{1/3}}{C} = \frac{T^{1/3}}{\lambda}$$

to yield a universal curve for all materials of similar grain structure. Here α' is the decay in dB/μsec.

The decay of intensity is an exponential curve. If α is the decay coefficient,

$$10\left[\log e^{-\alpha(C)}\right] = \text{loss in dB in 1 sec}$$

$$= -\alpha' \text{dB/sec}$$

$$\therefore \alpha = \frac{\alpha'}{10\ C\left(\log e\right)} \text{ per unit length}$$

σ is related to α' and α in a simple way. In a distance dx, the loss of intensity is given by

$$\frac{dI}{I} = -\left(\frac{\sigma dx}{T}\right) = -\alpha x$$

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*Reference is listed at the end of this appendix.

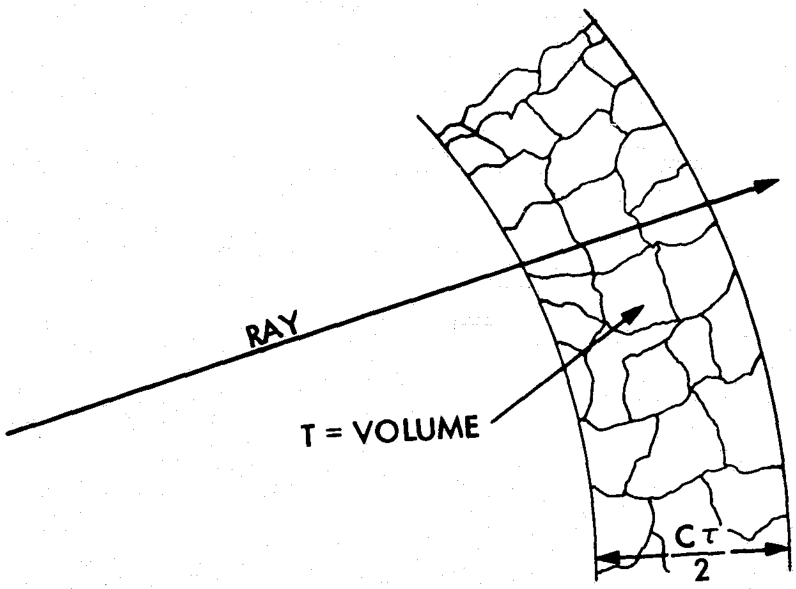

Fig. L-2. Number of Inhomogeneities Along a Ray

if the loss is assumed to be due to scattering of the energy by the scattering centers numbering dx(1/T), each of effective area σ. From the above

$$\sigma = \alpha T = \frac{\alpha' T}{10\ C(\log\ e)} \tag{7}$$

The quantity $\sigma/T^{2/3}$ is nondimensional and is equal to

$$\alpha T^{1/3} = \frac{\alpha' T^{1/3}}{10\ C(\log\ e)}$$

The plot of $\alpha' T^{1/3}/C$ vs. $T^{1/3}/\lambda$ is shown in Figure L-3 using data for nickel, brass and an alloy of iron and nickel. At low values of $T^{1/3}/\lambda$, the attenuation increases as the 4th power of frequency, changing to an exponent of 2 at high frequencies. The strength of the echo as a function of r, viz., S(r), is given by the equation

$$S(r) = 10\ \log \frac{\alpha' \lambda}{10\ C(\log\ e)} + 10\left(\log \frac{A}{r^2}\right) - \left(\frac{2\alpha' r}{C}\right) \tag{8}$$

where α' is the attenuation in db/µsec. Taking a typical value for the area of the transducer $A = 10\text{cm}^2$, curves of S(r) vs r are plotted for two frequencies, 100 kHz and 1 MHz for inhomogeneities of different sizes in Figures L-4 and L-5 respectively. The echo is observed from the transducer to such a distance that it is -60 to -80 dB. The echo is very weak and follows the inverse square law of decay at small values of $T^{1/3}$ and increases in strength as $T^{1/3}$ increases. But the curves at large $T^{1/3}$ cross each other showing that the excessive scatter leads to a quick decay of echo strength. Echos from a particular size of imhomogeneities can be heard from furthest away.

The above curves have to be modified slightly to include directionality effects, but the essential features are roughly as indicated. It is desirable to vary the frequency to suit the size of the inhomogeneities expected in the area around the borehole. For fractures, the effective "size of the inhomogeneities" is the spacing of the fractures.

Table L-1 gives a few values for the frequency giving maximum wall penetration and the penetration distance attained. The optimum frequency for fracture spacings of 0.1 and 10 cm is, respectively, 300 and 7 kHz. The corresponding wall penetrations at -60 dB are 1 and 4 meters. At -80 dB, the penetration is about an order of magnitude greater.

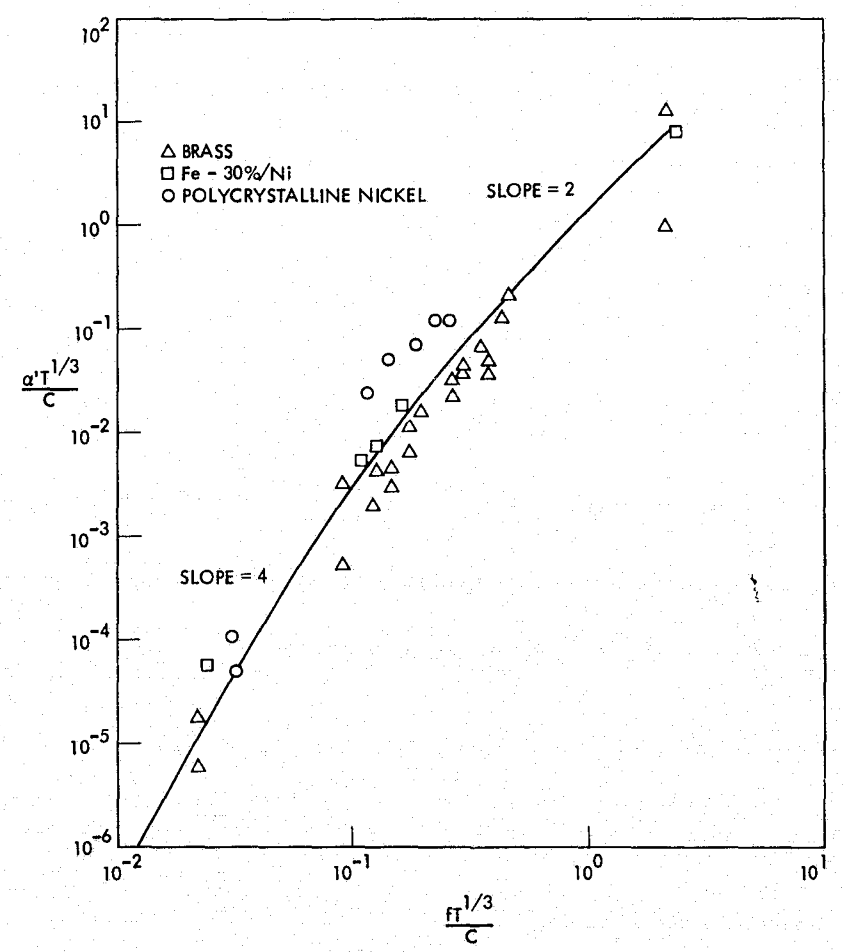

Fig. L-3. Dependence of Attenuation upon Frequency

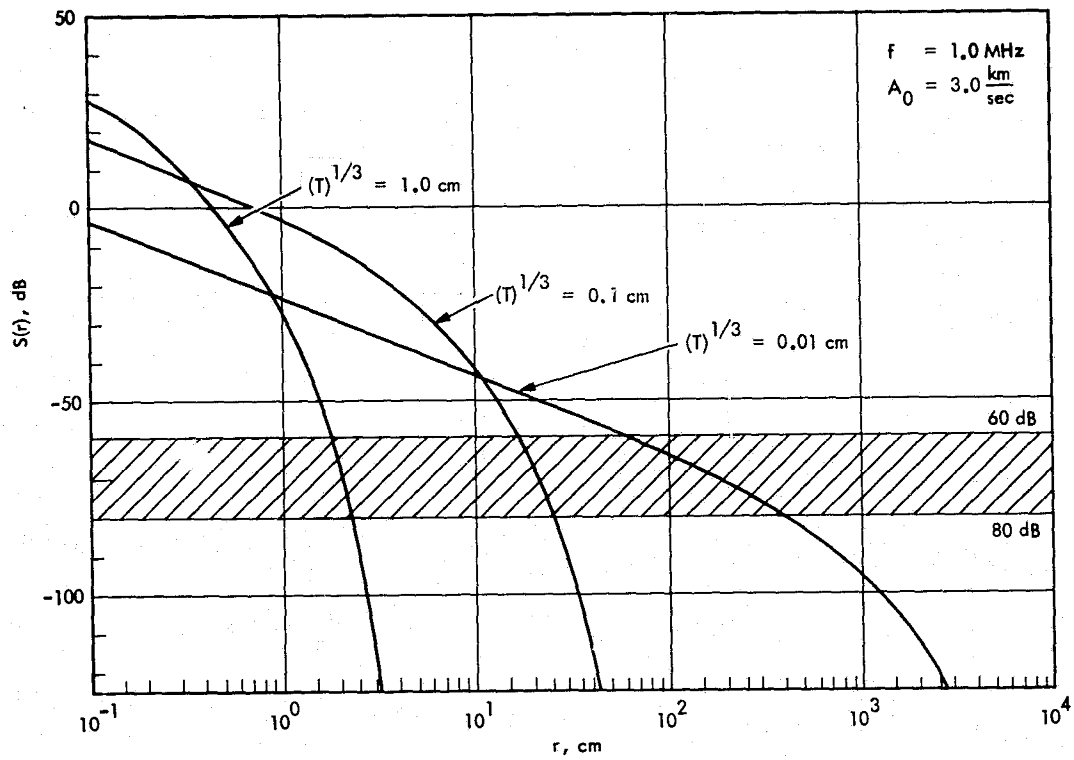

Fig. L-4. Dependence of Echo Strength upon Distance at f = 100 kHz

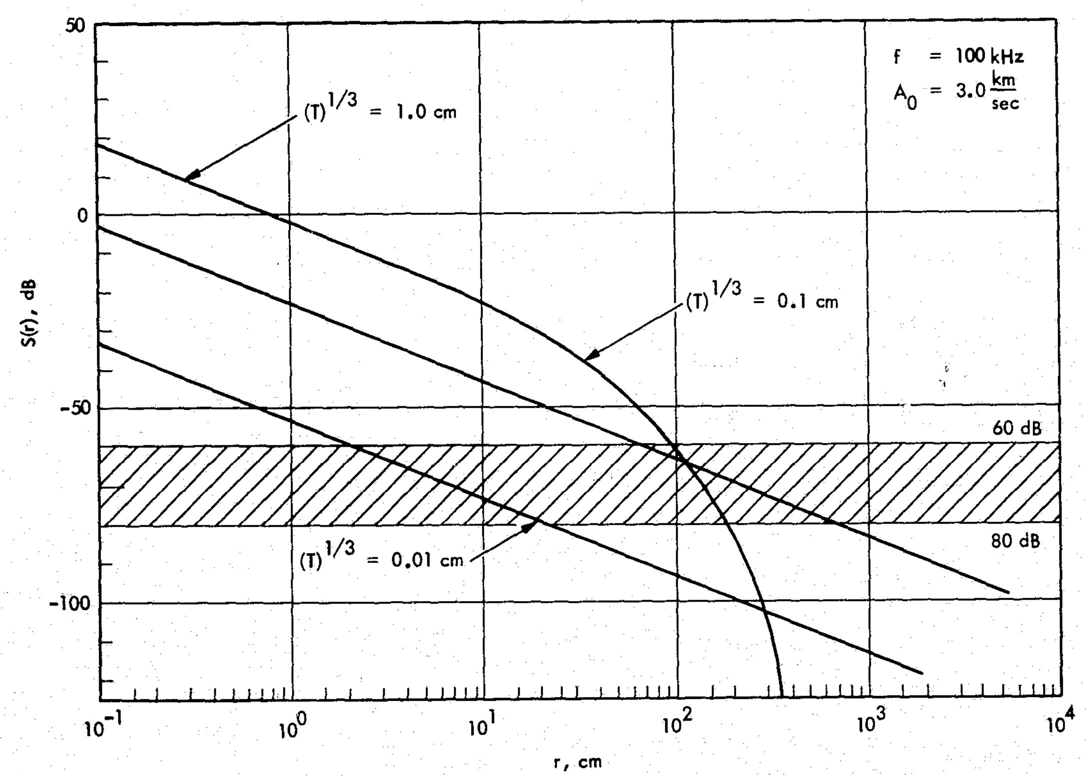

Fig. L-5. Dependence of Echo Strength upon Distance at f = 1.0 kHz

Table L-1. Estimated Frequencies for Maximum Wall Penetration and Effective Penetration Distance for Detection of Fractures by Acoustic Backscatter

Average Fracture Spacing cm	Frequency for Maximum Penetration kHz	Effective Wall Penetration Distance meters, At -60 dB
0.1	300	1.2
1.	40	2.4
10.	7	4.2

REFERENCE TO APPENDIX L

L-1 Physical Acoustics. Editor, Mason, Academic Press, IV, part B, 290-301, 1968.

APPENDIX M

CONSIDERATION OF SYSTEMS FOR EVALUATING GEOLOGICAL ANALOGIES

A method is described which will systematically aid in the evaluation of the potential for undiscovered petroleum in an area and which is based on the comparison of available data on the area with previous exploration experience in geologically similar areas. The utilization of this system in exploration programs may be expected to improve the chances of discovery of commercially exploitable petroleum reservoirs and can be used to better estimate the risk and financial value of a potential resource area.

The geologic analogy system has several useful roles in assisting the geologist, geophysicist, and manager in their work. It is an aid to the exploration staff and permits them to be more productive in their normal operations.

The system may be used in

1) Single Prospect Evaluation - Provides examples of the most similar previous plays for detailed comparison and study by the staff.

2) Prospect Probability Determination - Provides probability estimates for commercial production from a prospect for use in risk and economic analysis models.

3) Exploration Program Planning - Can be used to screen and prioritize prospects within constraints of budget and scheduling.

The geologic analogy system will allow the exploration organization to take greater advantage of computer data banks and analysis techniques to reduce the work load on the staff, thus permitting faster and more comprehensive play development. Such a system might also be useful in evaluating new or unproven prospecting techniques by providing correlations between success and specific physical parameters.

The search for the area most closely analogic is an interactive and iterative process. The search algorithms are refined through operator interaction with the machine. The output of this approach is a tabulation of the most similar previous exploration ventures. This type of output is valuable for preliminary evaluation of a play. A further output of the system, based on experience from the full-data file, is the evaluation of the success probability and size potential of the prospect. These outputs of the system can then be directly used as part of the data for making exploration decisions and can serve as inputs for economic and risk analysis calculations. The primary sources of data for the analogies search would be the user company's proprietary data base plus the currently available commerical data bases for the U.S. Separate commercial data bases exist of well-data files and field-data files. The company's own data base may include, also, data types, such as geochemical surveys, not contained in commercial banks. The use of both sources of data produces a more comprehensive set of past experience on which to base the analysis.

It is recommended in Volume 1, Section III-C, that a program to develop the geologic analogies system be performed. Intimate participation by the exploration industry will be required for the successful development of the system, and full implementation of the system would be carried out by the industry.

I. INDUSTRY STATUS

A. GENERAL METHODS

The approach towards exploration and towards geologic evaluation in the search for oil and gas is as varied as the industry. The approach and techniques used in the evaluation of prospects in frontier areas, such as in the outer continental shelf (OCS), differ significantly from the approach used to evaluate a new prospect within a mature oil basin. Typically, the target size for oil and gas strikes is considerably larger for frontier areas than for tested areas due to the higher risks and expenses. A brief description of some current approaches are described in the following paragraph.

Frontier area evaluation relies heavily on interpretation of seismic data with little control from subsurface geology. The identification of structure is the main contribution of seismic data. Values of key exploration parameters such as the percent of structure filled or porosity cannot be determined; only the range of expected values can be estimated. Monte Carlo analysis is frequently used which treats the key production parameters as random variables. The result is an estimate of the most likely quantity of petroleum within a structure.

The accurate assessment of the reservoir size in a lease tract is a key factor in its ultimate commercial development. Overly pessimistic estimates can result in the lack of development of a tract. Although sophisticated financial techniques are used by lease sale participants, bid prices frequently vary by a factor of ten for the same tract. Much of this variation is due to geologic interpretation and uncertainties in available data.

Exploration evaluation in mature basins having many wells and discovered fields is quite different. The search for new prospects may be based on the geologic interpretation of well-logs from wells surrounding the prospect. Modeling between wells is done to identify stratigraphic sequences. Oil/water interfaces are identified. From correlations of many wells, geologic cross sections are developed. If sufficient data is available, the stratigraphy of the area can be developed and a "fence diagram" of the region constructed. First structural traps are investigated, and then stratigraphic traps are searched for. Seismic data is relatively expensive compared to log data and may be used somewhat sparingly. The geologic objectives or play are usually well in mind based on knowledge of successes in the prospect area.

In basins with limited exploration and only sparse well control, the full range of exploration methods are used. The process involves the collection and evaluation of (see Table M-1).

1) <u>Surface Geology</u> - Characteristics of "masks" obscuring the subsurface geology, distribution and age of different types of rocks, structural geology such as the location and dip of fault planes at the surface, etc.

2) <u>Subsurface Geology and Geophysical Data</u> - Information on the geologic age, lithology, stratigraphy, textural and structural characteristics of the rocks, general and specific trap types, porosity and permeability, etc.

Table M-1. Types of Exploration Evaluation

Prospect Area	Available Data	Evaluation Techniques	Differences
Frontier Area	Seismic data	Seismic Interpretation	Geologic Uncertainties
(OCS)	Core Data	Monte Carlo estimation	Uncertainties in trap contents
	Surface Geology		
Limited Exploration	Seismic Data	Seismic Interpretation	Ambiguous Interpretations
	Some well data	Geologic	
Mature Basin	Extensive production data	Well-log correlation	Resolution due to well spacing
	Well-logs	Seismic data	

B. USE OF COMPUTERS IN GEOLOGIC EVALUATION

The application of computer methods to petroleum geology is the subject of widespread interest. Attention has focused both on techniques for frontier areas such as the OCS and on methods for use in the mature oil province. Large-scale computer programs have been developed to determine bid price for offshore lease parcels. Very little detail is usually known of the subsurface geology. As a result, many models in current use follow a stochastic approach and use Monte Carlo techniques to provide estimates of probable volume based on input uncertainty ranges in reservoir parameters.

The use of computers for geologic correlation in mature areas has concentrated on the evaluation and interpretation of digitized well-logs. In recent years, digitized well-log data covering a large portion of the U.S. have become available at reasonable prices. The development of digitized well-log libraries has made these data available to the whole exploration industry. Computer programs are being developed and used for evaluation of these well-logs for exploration. Also, more sophisticated computer programs are in use that accept log data as input and machine-plot isopach maps. Frequently programs include interactive control by the geologist and use cathode-ray tube displays of the output. These methods are being developed to locate new or overlooked traps. They may be applied to both structural and stratigraphic traps.

II. PETROLEUM DATA BANK STATUS

Nonproprietary data on U.S. petroleum fields and pools are available from several sources. Representative sources of publicly available information are International Oil Scouts Annual Review; American Association of Petroleum Geologists, (AAPS); Oil and Gas Field Data Bank and Map Project of North America, (1973); USGS data; Bureau of Mines computer printouts; publications from individual state agencies such as Annual Review of California Oil and Gas Production by the Conservation Committee of California Oil Producers; and Oil and Gas Annual Production, Active and Inactive Fields by the Oil and Gas Division of the State of Texas.

Recently, a data file called Petroleum Data System (PDS) has been established and provides access to nonproprietary information via a computer terminal. The PDS was developed by the University of Oklahoma under a 7-year contract with the Department of the Interior, U.S. Geological Survey (Ref. M-1)*. This system allows one to selectively search and retrieve from the data base information on fields and pools throughout the United States and Canada. Over 70,000 pools are currently in the system which contains annual and cumulative production identified by state, regulating district, geologic basin or province, country, on shore/off shore, section, township, and range. The information pertains to oil fields and pools but not to individual wells, except discovery wells. The data includes the geologic age of the producing formation, discovery year, field discovery method, trap type, present status of pool, discovery well data, status and types of wells, reservoir lithology,

*References are listed at the end of this appendix.

reservoir data, secondary recovery, crude oil analysis, water analysis and natural gas analysis. Details of the subdivision of several categories of data are given in Table M-2.

The PDS files can be accessed through the General Electric Company's Time-Sharing Service. As of July 1976, the PDS is used by 102 validated users representing 35 oil companies. It is to be noted that no software programs or analysis techniques are available in the PDS.

Table M-2. Categories of Data in PDS

Categories	Items
Field Discovery Method	Seismic, subsurface, seismic plus subsurface surface, ground magnetics, airborne magnetometer, photogeology, random drilling, oil well re-entered, geochemical, gravity, trend, other methods.
Trap Type (general)	Structural, stratigraphic, hydrodynamic other.
Trap Type (specific)	Anticline, salt dome, fault, nose syncline, terrace, fracture, homocline, dome, buried hill, regional facies changes, unconformity, lateral change in porosity and permeability, igneous intrusive, asphalt seal, biotherm, reef, biostrome, secondary chemical alteration, monocline, lens, other.
Reservoir Lithology	Siltstone, shale, chert, anhydrite, igneous, sandstone, dolomite, limestone, carbonate, other.
Reservoir Data	Primary drive type, porosity, permeability formation shrinkage factor or volume factor, recovery factor, saturation.

In surveying the various agencies and companies for data bank sources, one service company was found that specializes in collecting, cataloging, and filing well histories on magnetic tape (Ref. M-2). Their file contains histories on over 850,000 "back wells" in the U.S. and Canada and is kept current by inputs from various sources including their own field service. Well types are not restricted in that they include exploratory, development, producers, dry holes, and service wells.

The general format for this file is

1) General Information - Defines the well's identification, location description, status, completion date, total depth, etc.

2) Formation Tops, Bases, Cores - Source of data, formation codes, depth, cored intervals, core description and lithology when available.

3) Drillstem Tests - Test cycle, interval, recoveries, pressures, mud data analyses.

4) Production Tests - Engineering characteristics of tests run, treatment pressures, and recovery analysis.

5) Miscellaneous Data - Logs, surveys run, shows, drilling media, lost circulation, blowout, hole deviation, etc.

As a supplementary service, this company has the capability to digitize proprietary data and/or well-logs in the same format for compatible computer entry.

All of the foregoing discussions on data bank resources points out that a fairly complete collection of data is currently available for input to a geologic analogies system.

III. SERVICE INDUSTRY STATUS

Out of the several companies contacted, only one was found that was currently offering services associated with geologic analogies. Specifically, it had a computer program named RECON (Ref. M-3).

During the last four years, RECON has been used by several large companies to evaluate major exploration basins in the U.S. and abroad for stratigraphically trapped reserves. RECON is an exploration technique which utilizes digitized well-log data to determine the mechanics of a stratigraphic trapping mechanism that has been responsible for the occurrence of at least one commercial field. Several hundred well-log derived variables are evaluated by RECON to determine their exploration significance relative to the trapping mechanism. RECON evaluates these variables individually and in multiple with other variables. By using advanced statistical analysis processes and high-speed computers, exploration geologists are able to evaluate these geological variables and find those variables which have exploration significance.

After "proximity criteria", which conclusively map the productive limits of the known field, have been determined, the logs from the dry holes in the adjacent exploration area are then evaluated for the same proximity criteria. A contourable surface is then obtained in the exploration area which has closures and, hence, new exploration prospects. The final result is a set of maps containing several new prospects in the exploration area.

RECON has been applied over a very broad range of geological situations. These include predicting the proximity to porosity development in carbonates; mapping of critical permeability values for capillary pressure traps; predicting the presence of deeper structural growth from subtle stratigraphic changes penetrated in shallow holes; detection of geochemical "halo" effects associated with production; and mapping water salinity anomalies associated with production.

Normally, a RECON study takes 4 to 6 months. During this period, there is a high degree of man-machine interaction in running the program. Both the service company and the user's geologists are involved.

IV. AEROSPACE STATUS

An objective of this study has been to find a match between existing aerospace technological capability and the needs of the petroleum industry. For this purpose, a number of key areas of aerospace capability have been looked into: image processing; pattern recognition; systems analysis; data management; telecommunications, statistical analysis and artificial intelligence. The results of the evaluation on the basis of potential application to geologic analogies are

1) Areas of good potential for applicability:

a) Pattern Recognition - The use of pattern recognition techniques for aerospace and defense applications is well established. These techniques are currently in use for image processing of planetary photographs, robot vehicle guidance, sonar detection of submarines, and discrimination of seismic signals of nuclear tests from those of earthquakes. Recently NASA has successfully applied its space-developed techniques to the automated detection of chromosome damage.

b) Image Processing - Aerospace technology involving multispectral imagery of the earth's surface provided by satellites (ERTS: the Earth Resources Technolgoy Satellite) has been used to search for surface manifestations of natural resources, including petroleum, and to determine land characteristics such as terrain forms. Specifically the NASA developed VICAR programs (Video Image Communication and Retrieval processing programs) and MILUS (Multiple Input Land Use System) can be applied to the determination of the surface characteristics, the accessibility of prospect sites, and the decision on possible transportation media.

2) Areas of moderate potential for applicability: Systems analysis and data management: NASA capabilities in systems analysis can be utilized in the determination of system requirements and the

overall system integration. In data base management, NASA developed IBIS (Image Based Information System) can perform cross-tabulation, contouring and interfacing geocoded data with thematic maps or remotely sensed imagery. The JPL DIS (JPL Data Management and Information System) can store and update information as well as access it for reports and displays. However, those systems are not designed for a petroleum data base input.

V. RESULTS

A. DESCRIPTION OF CONCEPT

An interactive geologic analogies system is considered. It uses both proprietary and commercially available well and field data banks and an interactive pattern recognition system to produce outputs which assist the geologist and exploration manager in new prospect evaluation. Two types of output can be produced by the system; analogous prospect identification and prospect ranking or success probability. The output of analogous prospects identification would be a description of the most similar previous prospects. This data would then be available for geologic evaluation and comparison with the new prospect. It may be useful in pointing out key considerations and may indicate the need for further data acquisitions such as more geophysical surveys for the new prospects.

The production of prospect probability estimates represents a further use of the geologic analogies capabilities. Estimates of commercial potential and probable risk are calculated based on the past experience of geologically similar prospects. These data are used to evaluate the prospect relative to other prospects available for exploration. The estimates would provide a methodical framework for exploration program evaluation and may be useful for making drilling decisions and for planning future program requirements.

A key use of the geologic analogies system is to provide unbiased inputs from each prospect for risk analysis and economic analysis programs. The usefulness of risk analysis methods is increased through the use of less subjective probability values. Ultimately, it may be desirable for a petroleum company to develop a completely integrated system incorporating geologic analogy, risk analysis, and economic evaluation programs.

The geologic analogies system should be considered a tool to assist the geologist in his evaluation of a prospect and not as a replacement. The analogies system involves a high degree of man-machine interaction. It requires the geologist's inputs and management of the analysis process. The human mind is the most efficient pattern recognition system available for problems with 2 dimensions. However, multidimensional problems, having many types of data and input, are more difficult to systematically assess. The role of the computer for pattern recognition problems is most valuable in the case of multivariable problems which require the processing of large quantities of data.

The key advantages of the geologic analogies system are the reduction in time required for an expanded scope of prospect evaluation. The goal is to provide a higher success rate for exploration drilling due a more systematic evaluation of prospects.

The application of the geologic analogies system is aimed not only at an area or basin which has production but also to areas of interest with little or no commercial development. In the latter case it is assumed that there is some subsurface information from coring or dry wells. In frontier areas where subsurface information is not available, analogy identification will be more difficult. In mature basins with a high density of producing fields, the conventional practice of seeking new prospects from correlations between adjacent wells may be more direct.

B. DESCRIPTION OF SYSTEM

The geologic analogies system may be characterized by a large computerized data bank, an interactive pattern recognition system, and a high-speed input/output system. The system consists of

1) A data base containing well-log data, pool data, basin data, relevant geologic geophysical and production data and any other available data of interest.

2) A comprehensive software system that manages selectable pattern recognition subprograms and allows a high degree of man-machine interaction.

3) A computing/hardware complement which has cathode-ray tube/keyboard input/output with hardcopy plotting (for contour maps).

1. System Operation

As mentioned previously, the system will be highly interactive and will be operated by a trained petroleum geologist. System operation is divided into several stages as outlined in Volume 1, Figure 3-C-1. The first step is to input all pertinent information concerning the new prospect, including geophysical data, surface and basin geology, and well control. When no neighboring production exists, it will be necessary to extrapolate data from other basins. The next step is the determination of a similar set of basins.

The basin evaluation phase requires the development of a basin classification scheme. This classification scheme may be developed through the selection of key similarity parameters by the operating geologist, through the use of established basin rules (Ref. M-4), or through the use of unsupervised pattern recognition schemes. The role of the operator in parameter selection, algorithm selection, review, and final result determination are illustrated in Table M-3.

After the operator is satisfied that the classification scheme has selected a set of similar basins, the prospect evaluation step is initiated. A set of similar prospects are searched for from within the selected basins. The approach is similar to that for basin analysis. Based on operator input, key prospect parameters are selected. Factor evaluation algorithms are used to consolidate and compress data. Through manipulation of weighing factors and the use of additional screening such as cluster analysis and discriminant analyses a tentative classification process is generated. Only through checks and tests will the operator develop confidence in the results. A possible procedure is shown in Table M-4. Finally, a classification scheme is developed

Table M-3. Basin Evaluation Approach

Steps	Operation
Key Basin Parameter Selection	Decision by Geologist, based on experience
Apply Factor Reduction Scheme	Algorithm provides Reduced Set of Parameters
Review Parameter Set	Operator selects Final Set of Parameters
Initial Basin Evaluation	Use Operator Judgment or Established Similarity Rules
Select Clustering Algorithm	Basin Data Clustered and Displayed
Review Results	Operator Tests Basins Selected for Agreement
Iteration	
Select final classification Scheme	Set of Similar Basins Established

Table M-4. Prospect Evaluation Approach*

Steps	Operation
Key Prospect Parameter Selection	Decision by Geologist Based on Experience
Apply Factor Reduction Scheme	Algorithm Provides Reduced Set of Parameters
Review Parameter Set	Operator selects Final Set of Parameters
Initial Prospect Evaluation	Operator selects First Prospect Classification Rule
Select Clustering Algorithm	Prospect Data Clustered and Displayed
Review Results and Iterate	Cluster Operation Repeated
Select Discriminant Analysis	Prospect Data Discriminant Displayed
Review Results	Operator Tests Prospects Selected For Agreement
Select Final Classification Scheme	Set of Similar Prospects Established

*After: Schwade (Ref. M-5).

in which the new prospect is determined to be similar to a set of prospects, and a series of factors which link these prospects is determined to be most significant. The result of this step is the listing of the most similar previous prospects for detailed geologic evaluation and comparison.

The final step is the ranking of the new prospect based on the previous experience with the similar set of prospects. Table M-5 gives the prospect evaluation parameters. Among the similar set of prospects there will be those that have not produced and those that have had varying degrees of success. Applying discriminant analysis algorithms to the prospect selection factors, a rule is developed which allows the new prospect to be ranked with respect to previous prospects. From this ranking, a success probability can be derived. This output can then be used in judging a variety of new prospects under consideration.

Table M-5. Prospect Evaluation Parameters

A. Environmental Factors

- Proximity to identified oil/gas fields or indication
  - Well control, dry holes
- Depositional environment
- Source beds related to prospect
- Geologic history - basin history, depositional continuity, structural growth, tectonic condition, regional development, dip
- Subsurface fluids - fluid content
  - reservoir pressure
  - gas content

B. Stratigraphic Factors

- Trap configuration
- Rock properties - porosity, permeability
- Lithology

C. Structural Factors

- Closure
- Folds
- Orientation
- Faulting

D. Geophysical Data

- Nonseismic Data
- Seismic data quality
- Seismic technique
- Velocity control
- Well ties

2. System Elements

The data base used in the geologic analogies system will use both existing commercial data banks and company files. The Petroleum Data System (PDS) will be used to obtain basin and field data. As previously described, the PDS contains data on field discovery method, general and specific trap type, rservoir lithology, reservoir characteristics, and cumulative production. The well data file supplied by Petroleum Information Corp. contains complete data on the degree of success of each well. Formation, location and test results are available. These well file data are needed to add more detail to the subsurface geologic data and are used to obtain drilling success ratios. Only specific portions of the commercial file will be input to the geologic analogies data file, thus reducing the amount and cost of data which needs to be handled. In addition to these commercial data, each using company may wish to add its own proprietary data for its own use. This can be formatted in compatible form as mentioned earlier.

The interactive pattern recognition system is a flexible and adaptive tool as opposed to fixed software. This approach has been successful in development of operational pattern recognition systems for NASA data processing and military detection systems. Some of the advantages of the flexible approach are

1) The user has the flexibility to select the most useful algorithms for his problem.

2) The user may rapidly employ trial and evaluation techniques as required.

3) The appropriate balance and coordination between human and machine recognition abilities is achieved.

The pattern recognition package for the geologic analgies system includes subroutines for

1) Cluster analysis.
2) Discriminant analysis.
3) Factor analysis.
4) Sensitivity analysis.

The description of these elements and a general discussion of pattern recognition techniques are given in Appendix N.

VI. COMMENTS

Members of the exploration staff of the oil industry were contacted during this program, and their views on the geologic analogies system were requested. Opinions on the use of the computer to locate geologic analogies varied widely. Some industry exploration staff members were enthusiastic and others quite negative. Some supporters of the concept felt it was important as a means of bringing quantification into geologic evaluation. Others felt that this approach would facilitate more retrospective analysis which would result in the recovery of more oil. The key contribution of a geologic analogy system would be to help management screen new prospects and assist in developing future plans.

The reliability of the data base has been identified as a key problem. Quality control of the digitizing process of well-logs can create difficulties in using well files. Inconsistent and subjective interpretations can make logs from different wells difficult to compare. Also, inconsistencies may exist between data bases.

Some distrust of computers was encountered among mature geologists. They felt that data handling and sorting of previous plays was a better use of machine capabilities than prospect evaluation.

The use of the computer to reduce manpower requirements was considered an important point. Exploration staffs of the U.S. western region of several oil companies felt that it would help them cover the large range of their district. A few industry contacts implied that such system development was underway. One major company stated that these techniques had been previously tried and have since been discarded.

The geologic analogies system represents a distinct departure from currently available computer systems. The previously described RECON system requires data from many wells in a single basin. Its requirements for complete coverage of an area by wells with high-quality (digitized) logs limit its area of application.

Another example of the use of computer evaluation of well-data files for prospect identification was given by Forgotson and Stark (Ref. M-6). In the case presented, the well-data file was used to evaluate and map basin, play, and finally prospect potential. Well-logs from over 10,000 exploratory wells were needed for this evaluation.

Recently Abry (Ref. M-7) has described an application of discriminant analysis to the identification of new prospects within a basin that is undergoing exploration. Using hindsight analysis, a statistical analysis indicated the key geologic factors which were associated with oil occurrence during the initial phase of exploration. The predictive model then successfully located additional commercial fields which had been discovered in more recent exploration. The presented method is only applicable to prospects within a single basin. In addition, the predictive analysis focused on overall structural features such as vertical closure.

In conclusion, there appears to be a need for a geologic analogies system which can make maximum use of available well and field fields in the evaluation of new prospects. Despite indications by a few companies of some development effort in this area, there is no operational analogies system in widespread use. A system which could be used by the majority of the exploration industry not just the largest companies would provide the most benefit.

VII. RECOMMENDATIONS

The recommended effort includes a 2- to 3-year development and dissemination process. The program consists of three phases:

1) <u>System Development</u> - The definition of specific algorithms and data requirements, user operation requirements, software development, and system integration. (Approximately 1 year.)

2) Prototype Testing - System tests will be performed on a variety of test cases; modifications and improvements will be performed. (Approximately 1 year.)

3) System Dissemination - Information on implementation and use of system disseminated to potential users. (Six months.)

The chances appear favorable that, if development is undertaken, an analogy system will be in use within 5 years.

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APPENDIX N

PATTERN RECOGNITION TECHNIQUES

I. OVERVIEW OF PATTERN RECOGNITION

The purpose of this appendix is to provide a conceptual introduction to pattern recognition. This survey is oriented toward the techniques with the most applicability to petroleum exploration.

A. THE MATHEMATICAL (STATISTICAL) APPROACH TO PATTERN RECOGNITION

The literature in pattern recognition is very rich. In a recent survey article Kanal* (Ref. N-2) found that between 1968 and 1974 over 500 journal articles have been published in the English language engineering literature and nearly 20 books on pattern recognition. The purpose of this survey is not to duplicate existing surveys or books. The major thrust is to treat pattern recognition from a broad-brush point-of-view, focusing upon those concepts and techniques which seem to be most appropriate to petroleum exploration.

The particular area of pattern recognition that will be considered is what is known as the mathematical or the statistical approach to pattern recognition. This will be contrasted with the "structured approach" to pattern recognition.

The basic motivation behind the mathematical approach to pattern recognition is to discover the inherent structure relationships in some data set. Often, this relationship can be characterized by statistical and mathematical relationships. Most of the literature in this area evolved from the area of statistics. Certain classical statistical disciplines, such as linear regression, certainly should be included in the general area of pattern recognition. However, the purely statistical interpretation is somewhat limited in that much of the work can be interpreted in a nonstatistical way. Many algorithms assume no special statistical structure of the data.

The structured approach to pattern recognition has grown out of the area of artificial intelligence. The primary motivation has been to automate human recognition of tasks. Applications have included the translation of printed, written, and spoken language. These applications have had limited success. The only commercial success has been the character recognition of the printed character. One of the factors that has limited successes in this area is that very little is known about how the mind performs these tasks. It has been established that the mind must manipulate large data bases to perform recognition. However, what this data base is and how it is manipulated are issues that are poorly understood for many simple tasks.

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*The reference for the remainder of the discussion is based upon one of the better text books, Duda & Hart (Ref. N-1). Note: References are listed at the end of this appendix.

With these observations, it seems to be reasonable to exclude structured pattern recognition techniques from this survey. The mathematical or statistical approach seems to be more consistent with techniques that would be useful for oil exploration. Mathematical techniques have been successfully applied to a wide range of sciences, including geology. The emphasis of these applications is to develop new insights into data relationships; this is consistent with the needs of the petroleum exploration.

B. THE ROLE OF LEARNING IN PATTERN RECOGNITION

Pattern recognition is a useful tool for scientific inference. The feature space represents some measurable aspect of some object. The classification represents some other aspect of an object that is not measurable. Of course, a complete scientific theory may enable to infer the unknown aspect directly in terms of the known aspect. However, in many cases such a scientific theory is lacking or incomplete, but many data exist from which such a theory can be constructed. These are cases in which the power of pattern recognition is of most use to the scientist.

The power of pattern recognition is that successful algorithms can be developed from actual data via a learning process.

The learning process can be supervisory or nonsupervisory. The supervisory learning process is based upon data in which the unmeasurable aspect, i.e. the classification category, is also known. Nonsupervisory learning is when the classification category is not known. Algorithms by which pattern classification schemes are develped from basic data are sometimes referred to as "learning algorithms." One of the oldest and simplest learning algorithms is Fisher's discriminant analysis technique (Ref. N-3), which will be discussed next.

C. DISCRIMINANT ANALYSIS TECHNIQUES

Most pattern recognition schemes employ discriminant functions. In order to define the general structure of pattern classifiers that use discriminant functions, it is necessary to introduce some mathematical notation.

The Fisher linear discriminant analysis technique is the most popular technique for constructing such discriminant functions. As the name suggests, the discriminant functions are linear. Thus, discriminant functions split the feature space into regions that are separated by surfaces. The two dimensional case is illustrated in Figure N-1. Two classes of objects are illustrated. The line is the set of points where both discriminant functions are equal, i.e., $g_1(x) - g_2(x) = 0$. As illustrated, this line does not perfectly separate the samples into two groups. As is the case with most pattern recognition techniques, errors are made. However, the discriminant analysis techniques select the particular discriminant functions to minimize the errors in some sense. In cases where linear discriminant functions are not appropriate, other forms are used.

The technique to develop discriminant functions requires the use of mathematical subroutines. For the mathematical equations and algorithms, the reader is referred to the literature.

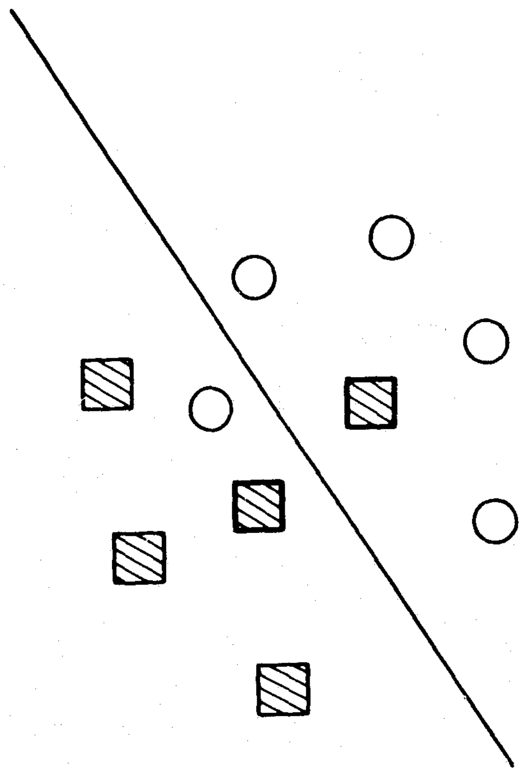

Figure N-1. Two Dimensional Example Illustrating the Fisher Discriminant

Although the discriminant analysis techniques grew out of statistics, they can be applied without any statistic interpretation. Next a statistical interpretation is provided.

D. STATISTICAL TECHNIQUES

Statistical techniques assume that probabilistic models exist that relate objects to the feature space. Mathematically, this assumption is equivalent to the assumption of the existence of the probability density functions characterizing the feature of an object, given the knowledge of its class denoted by $p(x/w_i)$ $(i = 1, .., n)$.

Thus if $p(x/w_i)$, the probability density of x, given w_i, is known, then one can form a discriminant pattern recognizer by setting the ith discriminant function $g_i(x)$ to be $p(x/w_i)$. This is equivalent to the maximum likelihood estimator, that is, the hypothesis is chosen which most likely explains the data.

If <u>a priori</u> probabilistic information is available, then a Bayesian estimation scheme can be used. The <u>a priori</u> knowledge usually takes the form of $\{p(w_i), i = 1, .., n\}$, where $p(w_i)$ is the a priori probability that the hypothesis w_i is true. With the knowledge of $p(w_i)$ and $p(x/w_i)$, the probability $p(w_i/x)$ can be determined using Bayes' theorem:

$$p(w_i/x) = \frac{p(x/w_i)p(w_i)}{\sum_{i=1}^{n} p(x/w_i)p(w_i)}$$

By setting $g_i(x) = p(w_i/x)$, the maximum a posteriori estimator is used, i.e. the hypothesis that is most likely true, given all available information, is chosen.

For many applications, including oil exploration, none of the above statistical classifiers may be satisfactory. For example, although the evidence may indicate that there is less than a 50% chance that there is oil at a spot, it may be still profitable to act as if there is oil there because the expected gain is high enough. The introduction of the notion of gains or returns into pattern recognition was done early by Neyman and Pearson (Ref. N-4). Mathematically one introduces a loss function $\lambda\ (d_i/w_j)$, which is a measure of the loss that would occur if decision (d_i) is made based upon the assumption hypothesis w_i is true, when in fact hypothesis w_j is true. Then the risk function $R(d_i/x)$ may be defined as the expected loss if x is observed and the decision d_i is implemented. $R(d_i/x)$ is given by

$$R(d_i/x) = \sum_{j=1}^{n} \lambda(d_i/w_j)p(w_j/x)$$

The minimum risk discriminant pattern recognition scheme is obtained by setting $g_i(x) = -R(d_i/x)$.

E. ESTIMATION AND STOCHASTIC APPROXIMATION TECHNIQUES

A central key to the decision oriented pattern recognition process is the probability density functions $p(w_i/x)$, $i = 1, .., n$ (or equivalently $p(x/w_i)$, $p(w_i)$). These functions summarize all that the data tell and will provide a major input to any decision process in which x is used.

The major difficulty in any application of pattern recognition is to determine $p(w_i/x)$. There are very few cases where $p(w_i/x)$ is known. In most cases, a learning process from given data is necessary to determine $p(w_i/x)$.

If the form of $p(w_i/x)$ is known but some parameters must be found, then particular parametric estimation techniques are available. If the form is not known, then nonparametric techniques are available. For a given set of data, parametric techiques are more powerful than nonparametric techniques and, hence, are preferred if assumptions warrant using them.

In a typical parameter estimation application, for example, one could assume that $p(x/w_i)$ is a normal distribution with some subset of the means and covariance elements unknown. These elements are then estimated.

In a nonparametric case, the probability density function is often assumed to be constant over a Parzen window. The art of approximation is choosing these windows in terms of the data. Probably the best approach is the nearest neighbor algorithm in which the windows are chosen so that the same number of samples are in the same box.

F. UNSUPERVISED LEARNING - CLUSTERING

These techniques are used for cases where no known classification structure exists. A major function of these algorithms is to cluster input data into a number of different sets. The basic use of these algorithms is to determine the inherent structure of a given data set. This may enable the analyzer to partition the data set in uniform regions where more sophisticated analysis techniques can be applied.

One approach to clustering is to view it in terms of a generalized Bayesian learning when the number of classes are also unknown including probabilistic parameters. This approach leads to more complications than other approaches that abandon the statistical models in favor of similarity measures.

A similarity is a metric denoted, say, by d(x,y) that measures the similarity between two objects. The rationale for clustering is that objects that are close together should be grouped together rather than those that are far apart, measured according to the similarity measure. Such a measure is the Euclidean distance. Of course, a change of scale will change the Euclidean metrics. In order to avoid this, one usually normalizes the data prior to clustering.

One way of normalizing the data to translate, rotate, and scale the data so that the data has zero mean and unit variance along each coordinate. This transformation employs a principal component analysis, i.e., vectors of the covariance matrix.

Another way of avoiding the above process of normalizing the data and using the Euclidean distance is to use a normalized distance such as the Mahalanobis distance.

Many clustering processes employ a criteria function that measure the quality of any partition of the data. Then the problem is to find a partitioning of the data that maximizes (or minimizes) the criterion function.

The simplest and most widely used criteria function is the sum-of-squared-error criterion. If X_i is the ith cluster with n_i samples, let m_i be the mean of the samples

$$m_i = \frac{1}{n_i} \sum_{x \in X_i} x$$

Then the sum of squared errors is defined by

$$T = \sum_{i=1}^{n} \sum_{x \in X_i} \left|\left| x - m_i \right|\right| ^2$$

This type of criterion would be applicable to problems for which data group together into compact clouds.

To partition the data, iterative optimization techniques may be used. Another approach is to employ hierarchical clustering procedures. One hierarchical clustering algorithm is the agglomerature hierarchical clustering algorithm, which merges the two closest sets (as determined by same criteria) until the distance between the two closest sets exceed some threshold.

G. FEATURE REDUCTION TECHNIQUES

One of the problems that pattern recognition techniques have with many applications is that the dimension of the feature space is often large. One of the major steps in most application is the reduction of the dimension of x. Several techniques exist that can be applied to this and have been discussed: discriminant analysis, principal component analysis, and clustering techniques. This step of feature reduction can precede and be used with stochastic approximation techniques.

II. APPLICATIONS OF PATTERN RECOGNITION

Pattern recognition is being applied in many areas including geology and in limited contexts to petroleum exploration. Some applications follow.

Natural resource identification via remote sensing is the primary area for the application of pattern recognition by NASA. The primary concern is to use multispectral imagery of the earth's surface, as provided by satellites, to map the resources of the earth's surface. Particularly, one is interested in determining terrain forms, uses of land, crop production, bodies of water, forests, and locations of mineral wealth. Multispectral data is also useful in monitoring pollution and crop diseases.

To perform resource identification in an efficient way, pattern recognition techniques are applied in connection with digital processing. Clustering techniques are applied to determine regions of similar nature. Then ground expeditions are used to determine ground truth. By iterating this process, pattern recognition techniques can be developed that identify specific resources or features.

Pattern recognition techniques have been widely applied in the area of detecting and diagnosing of diseases. Applications of pattern recognition have been made to speech, written, and printed language recognition and translation. In automated factory production, pattern recognition is used for automatic detection of flaws and object recognition for the purposes of automated assembly.

In geological chemistry, pattern recognition techniques have been used to determine the most significant geological factors causing variations of geological chemistry. Traditionally, principal value techniques have been used. Recently Benzecri (Ref. N-5) proposed a new technique, called "correspondence," similar to principal value analysis that avoids the normalization problem and that has been applied to the study of geological processes. This technique, in conjunction with cluster analysis, has been applied by Dagbert and David (Ref. N-6) to the analysis of geochemical data. This analysis showed that 97% of the total variation of the data could be explained by five factors.

Currently a study team composed of Americans and Russians are applying pattern recognition to the study of earthquakes (Ref. N-7). A study was made to determine whether certain geological features or combination of features could be related to epicenters located in California. Both supervised and unsupervised techniques were used. Distinctive features were determined based upon applying learning algorithms to a given set of data. Verification of the significance of these features was carried out on data not used by the learning algorithms. Current work is being performed on time series data to determine causal factors related to earthquakes. Pattern techniques are also being applied to the study of seismic data to distinguish between earthquakes and nuclear tests (Ref. N-8). Recently Sriram, et al. (Ref. N-9), report success in applying pattern recognition to seismic data in determining different classes of stratigraphy.

In 1966, Bongard, et al. (Ref. N-10) proposed the use of pattern recognitions for petroleum exploration. The techniques that were applied were those reported by Gelford (Ref. N-7) in the earthquake analysis. Scientific Software Corporation (Ref. N-11) sells services based upon linear regression and discriminant analysis techniques applied to well-log data. Abry (Ref. N-12) also reports successful results applying discriminant analysis techniques applied to play studies, using well log data and other geological data. C. Bois (Ref. N-13) applied clustering techniques to world-wide geological parameters and determined nine major zones.

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APPENDIX O

HIGH-PRESSURE DRILLING PROBLEMS

Field tests of high-pressure drilling by investigators (Ref. O-1)* brought out a number of problems, as follows:

I. PUMP LIFE

The standard mud pump is found to be structurally sound and capable of producing the pressures needed for high-pressure drilling. It was modified in order to adapt it for this use. Pump life is drastically shortened by use at high pressures of 10,000 to 15,000 psi. At these pressures, pump life is 40 to 60 hours between overhaul. The expendable parts of the pump must be replaced. These are the poppets and seats of poppet valves and all seals.

A. VALVES

The valves are spring actuated poppets closing with pressure change. All valves must hold against the full mud pressure exerted by the pump. The dynamics of this valve closing system will allow full pressure to develop before the valve is fully closed. The resulting high-velocity terminal flow rate is responsible for valve failure. The failure is poppet and valve seat erosion.

B. DYNAMIC SEALS

Pump seals' functional life is about the same as valve life. Seal failure is caused by heat. The seals being used are dependent on applied external lubrication. A contradictory demand is placed on the seal. The seal must accept lubrication and also seal against the fluid being pumped. The seals tend to also seal out the lubrication and allow friction-inducted heat to degrade them and eventually cause their failure.

The pump operational life goal is 300 hours. If this can be achieved, pump life will be adequate for economic high-pressure drill costs.

III. SWIVEL JOINT

The seals in the swivel joint are now adequate for economic functional life. Since these seals are rotary in place of reciprocating, the seal normally has longer life. An improvement in the pump seal can influence the seal life in the swivel head.

IV. HIGH-PRESSURE HOSE

Steel cable reinforced neoprene rubber hose has adequately taken care of the high-pressure feed to the drill string.

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*Reference is listed at end of this appendix.

V. DRILL PIPE JOINTS

Drill pipe joint sealing is done by seat gasket or O-ring and thread doping. If properly done, successful seals are achieved; however, care must be used in applying the correct amount of dope.

VI. RIG PREPARATION

All high-pressure drilling as of this time has been on an experimental basis. Conventional rigs have had added special high-pressure components. The proper rig preparation for high-pressure drilling does not require a redesigned rig but one fitted out to perform efficiently. Safety methods for handling high pressures must be used. The drilling operations will be conducted from a specially reinforced doghouse during all times when the high pressure is in use. Remote controls of the drilling operations from the doghouse have been successfully demonstrated. The pressure feed lines will be installed in trenches, and special high-presure lines will be used. There will be no men exposed during the ultrahigh-pressure operations.

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APPENDIX P

DOWN-HOLE DRILL MOTOR DESIGN

In the design of Rockwell International, Rocketdyne Division, the turbine drill unit consists of four major components. They are

1) Hydraulic turbine.

2) Gearbox.

3) Bearing housing with drill bit.

4) Drill propelling unit.

I. HYDRAULIC TURBINE

Both units are designed to operate with water or drilling fluid (mud). In a four-stage radial inflow turbine, all rotors operate in parallel and at the same pressure ratio. An arrangement of four pressure manifolds fed by two inlet pipes, 180° apart, supply the flow through respective nozzle banks to the turbine rotors. The axial flow turbine requires also four stages but only one manifold. The turbine with its bearings and seals is self-contained within the unit. It is estimated that with an available inlet pressure, 700 psi, and a pressure ratio across the turbine of 10, the available power to the drill bit will be 150 horsepower. The turbine drive shaft is connected to the speed reduction gearbox. The turbine rotors are approximately 6 inches in diameter and rotate at about 3000 rpm at full torque output. The turbine free speed is about 5500 rpm. The turbine pressure drop is approximately 700 psi at a flow of 600 Gpm.

II. SPEED REDUCTION GEARBOX

The gearbox is designed for a 30:1 speed reduction. It is self-contained and sealed against environment. The fluid leaving the turbine is used to cool the gearbox by flowing between the outer cylinder wall and the gearcase housing.

III. BEARING HOUSING WITH DRILL BIT

The bearing housing is a self-contained unit that is detachable with the drill bit for ease of installation. The thrust load generated by the driving power of the axial propulsion unit is reacted by an arrangement of two spherical roller thrust bearings in series, in combination with a large ball bearing for radial load control. The bearing housing contains the needed oil supply, and and the bearings are lubricated by internal recirculation. The bearing housing is cooled by fluid from the turbine exhaust passing through the bearing housing shaft into the cutterhead and by the flow moving from the drill head upwards. The thrust bearing unit is designed to completely absorb rotational loads within the bearing assembly without influencing the gearcase or the hydraulic turbine. The axial load is passed from the outer bearing housing to the outer housing cylinder and transferred through the propelling spindle into the hydraulic rotary motor which also contains a large Kingsbury-type thrust bearing.

IV. DRILL PROPELLING UNIT

The drill unit is self-propelling after it is below the surface. An arrangement of expanding shells, hydraulically actuated, positions the drill unit in an axially fixed position. A rotary hydraulic motor with a hollow threaded spindle rotates and moves a sturdy threaded shaft, which is fixed to the hydraulic turbine housing, downward until it reaches its maximum extension. By automatic signal, the hydraulic shell actuators are retracted, and the hydraulic rotary motor is reversed, causing the propelling unit to follow the drill unit until contact; after which, the cycle is repeated.

High velocity of the well drilling fluid (mud) can have the effect of sandblast. Therefore abrasion within the hydraulic turbine is of concern. A study of high-pressure and large-flow coal slurry pumps is underway. Advanced design and manufacturing methods are being thoroughly studied. Associated research is proceeding on the development of various techniques of vapor deposition of tungsten carbide on other host materials. Another development program is concentrating on injection molding and sintering of aluminum oxide, nickel and tungsten. Injection molding offers a solution to the problem of forming complicated shapes of extreme hardness for use in pumps and hydraulic turbines that operate with abrasive fluids such as coal slurry or drilling mud.

The rotor tip speed of the hydraulic turbine rotor for the proposed deep well drill is about 78 feet per second which is comparable to the 75 feet per second limitation used in conventional slurry pumps.

APPENDIX Q

TESTS OF RESONANCE TUBE VERSION OF COMBUSTION-FRACTURE DRILLING

This appendix describes some laboratory tests made to evaluate one particular configuration suggested for combustion fracture drilling and lists possible additional tests.

I. BACKGROUND

Many alternatives to conventional rotary and percussive drills for drilling and breaking rock have been proposed and investigated to some degree. To assist in ongoing studies of the exploration and recovery of petroleum and coal, it seemed desirable to gain experience with methods of breaking rock and, in particular, to explore potential improved methods of drilling. The resonance tube drill described herein has not been proposed or investigated before to our knowledge.

II. PROGRESS

Preliminary tests have been conducted with an underexpanded supersonic jet flow impinging on an adjacent solid structure. The gas source can be either compressed air or combustion products of a rocket engine. Under a wide range of flow and geometric conditions, this device produces pressure pulsations of varying frequencies on the interacting surface. If the underexpanded supersonic jet flow impinges on a solid structure with a cavity (resonance tube system) as indicated in Figure Q-1, the pressure pulsations are also accompanied by intense heating of the gas close to the endwall of the cavity. Resonance tube flows have been investigated in connection with igniting rocket motors. Endwall gas temperatures as high as 1000°K or more were obtained in ambient stagnation temperature jet flows in less than 20 ms. The property of high-temperature pressure pulsations of this device suggests its potential to break or drill various kinds of rocks. The breakage of rocks may occur either by fatigue, by the high-frequency pressure pulsations, or by thermal stresses, or all three. Lower frequency pressure pulsations near the natural frequency of rock also can be produced.

The preliminary investigation consisted of measurements on a flat metal plate and rock studies.

III. FLAT-METAL PLATE

In the first study, nitrogen gas flowed through a convergent nozzle with exit diameter d = 2.03 cm and impinged on a flat metal plate normal to the jet (see inset, Figure Q-2). The distances between the nozzle exit and the plate was 1.0 and 1.5 of the nozzle exit diameter d. A fast-response pressure transducer with resolution of 0.02 psi, rise time of 2 μs, and frequency response from 2 to 40,000 Hz was mounted flush on the plate at the jet centerline. The ambient pressure P_∞ was atmospheric, and the nitrogen jet stagnation pressure P_0 was varied up to 8 atm. Spark shadowgraphs were also taken of the flow and shock structure in the gap between the nozzle and plate. Results of this investigation are shown in Figures Q-2 to Q-6.

In Figure Q-2, the magnitude of the pressure fluctuation ΔP normalized by the ambient pressure P_∞ is shown as a function of the nozzle pressure ratio $R = P_0/P_\infty$ with spacing s/d = 1.5. For the range of nozzle pressure ratios investigated, there were two local peaks in ΔP: the first one at a pressure ratio of approximately 2 (near the choked flow condition of R = 1.9) and the second peak at a pressure ratio of about 4.5. The corresponding values of $\Delta P/P_\infty$ were about 1 and 3, respectively. A study of the jet-flow spark shadowgraphs and endwall pressure traces indicated that the first peak in pressure fluctuations ΔP at the plate occurred when the two shock cells collapsed to one shock cell randomly. As the pressure was incurred beyond $R \simeq 3.0$, only one shock cell was present in the jet flow. As the nozzle pressure ratio was increased to about 4.33, this shock wave began to oscillate with large amplitude. This resulted in strong plate pressure fluctuations ΔP as shown in Figure Q-2. The strength of these pressure pulsations then decreased as the nozzle pressure ratio R was increased. Figure Q-3 indicates the fluctuating pressure trace and one of the shadowgraphs as a pressure ratio of 4.33, at which large amplitude shock oscillations occurred. The normal shock wave standing in the jet flow oscillated at a very high frequency f of about 20 kHz (frequencies at the pressure peaks are indicated in Figures Q-2 and Q-5).

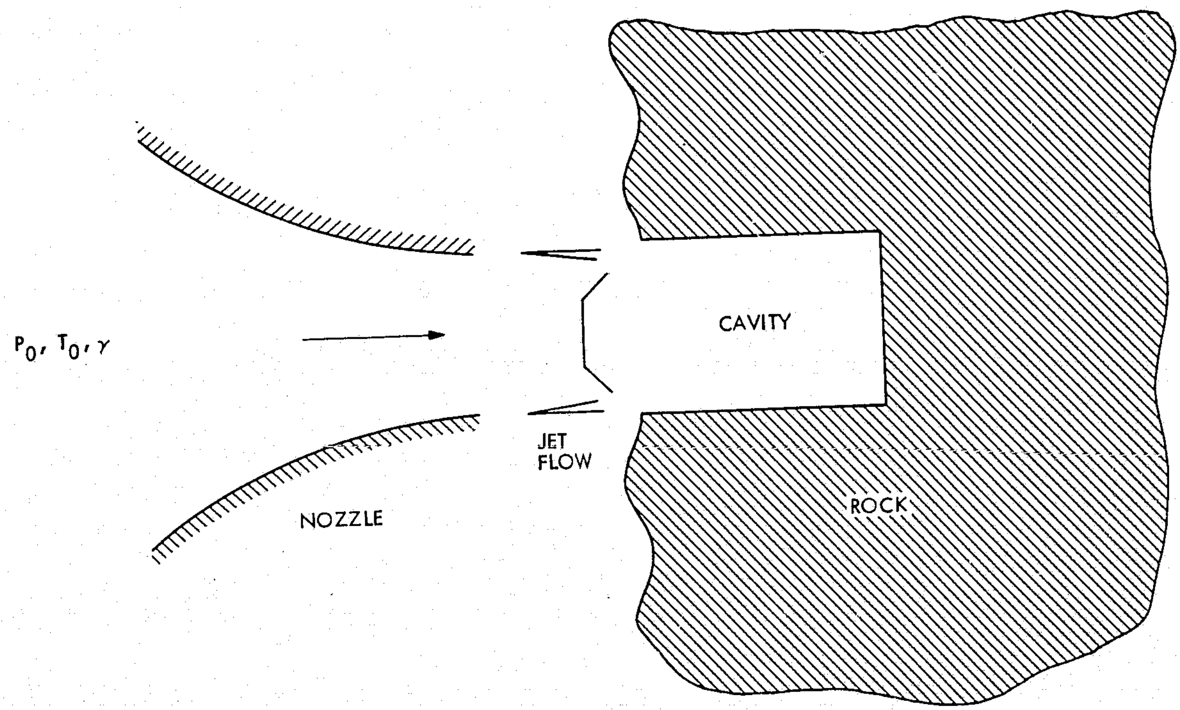


Figure Q-1. Resonance Tube Drill System

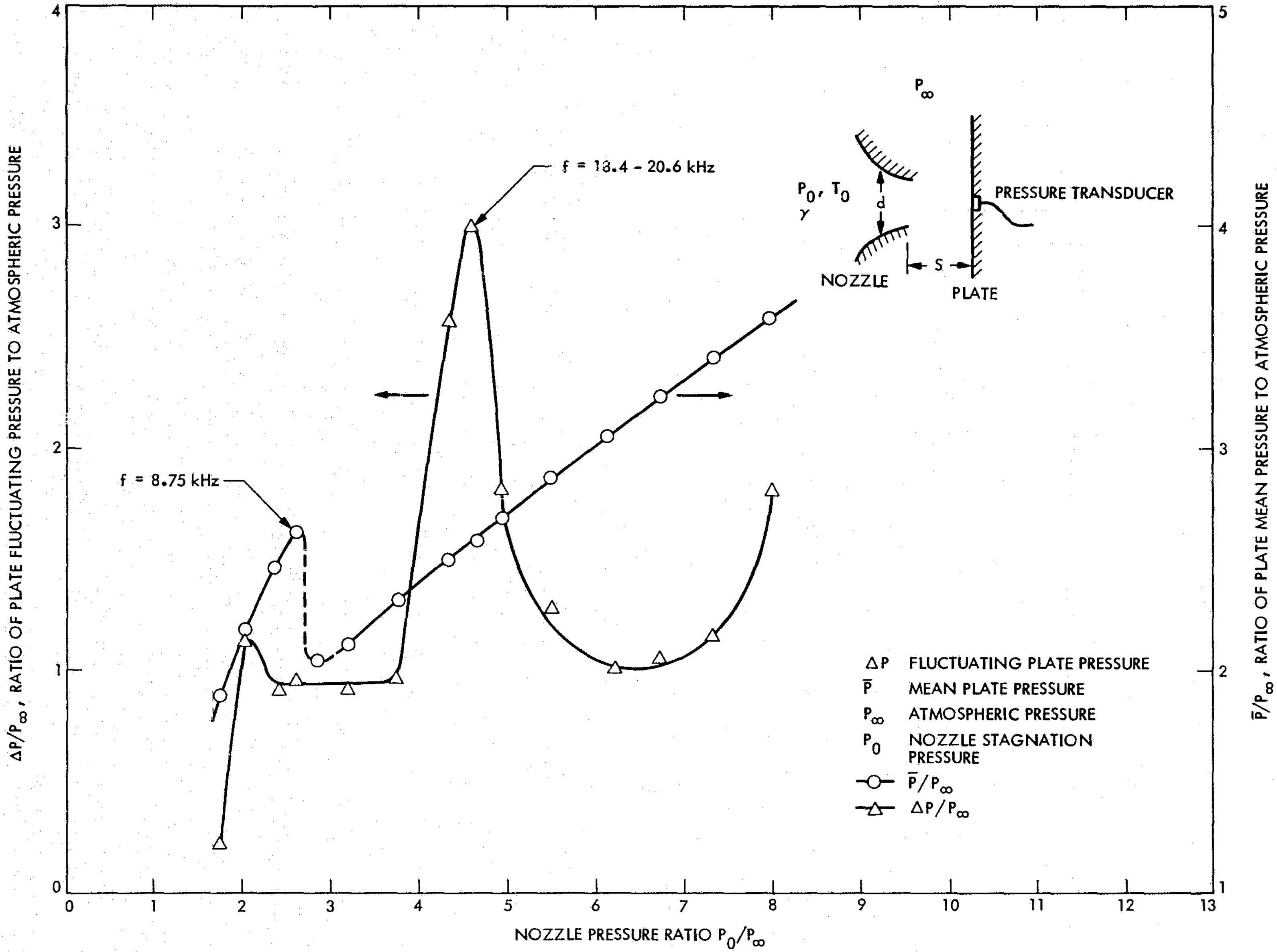
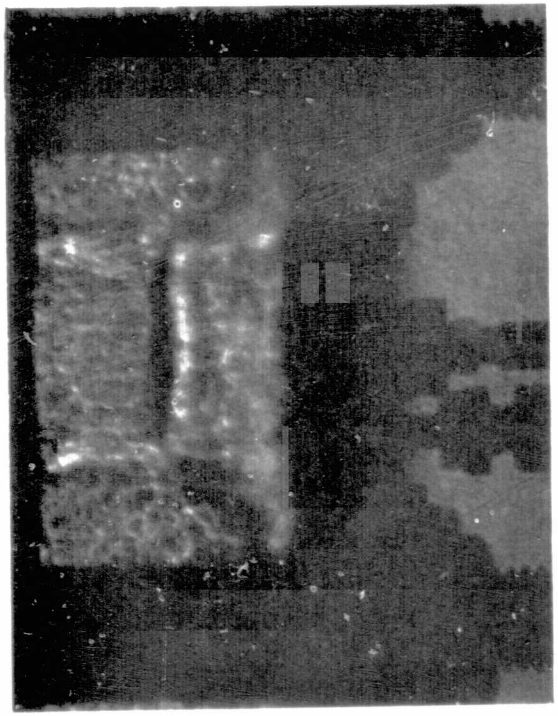
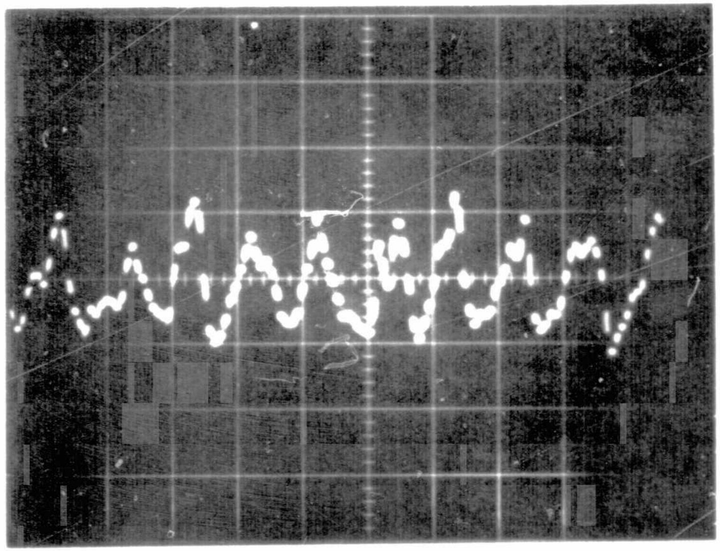


Figure Q-2. Ratio of Plate Mean and Fluctuating Pressures to Atmospheric Pressure for Different Nozzle Pressure Ratios R with Spacing $\frac{s}{a}$ = 1·5



(a) SHADOWGRAPH OF JET-FLOW BETWEEN NOZZLE EXIT AND PLATE



(b) PLATE FLUCTUATING PRESSURE TRACE WITH VERTICAL SCALE 13.16 psi/div HORIZONTAL SCALE 50 s/div

Figure Q-3. Shadowgraph and Plate Pressure Trace at Nozzle Pressure Ratio R of 4.33 with Spacing $\frac{s}{d}$ = 1.5

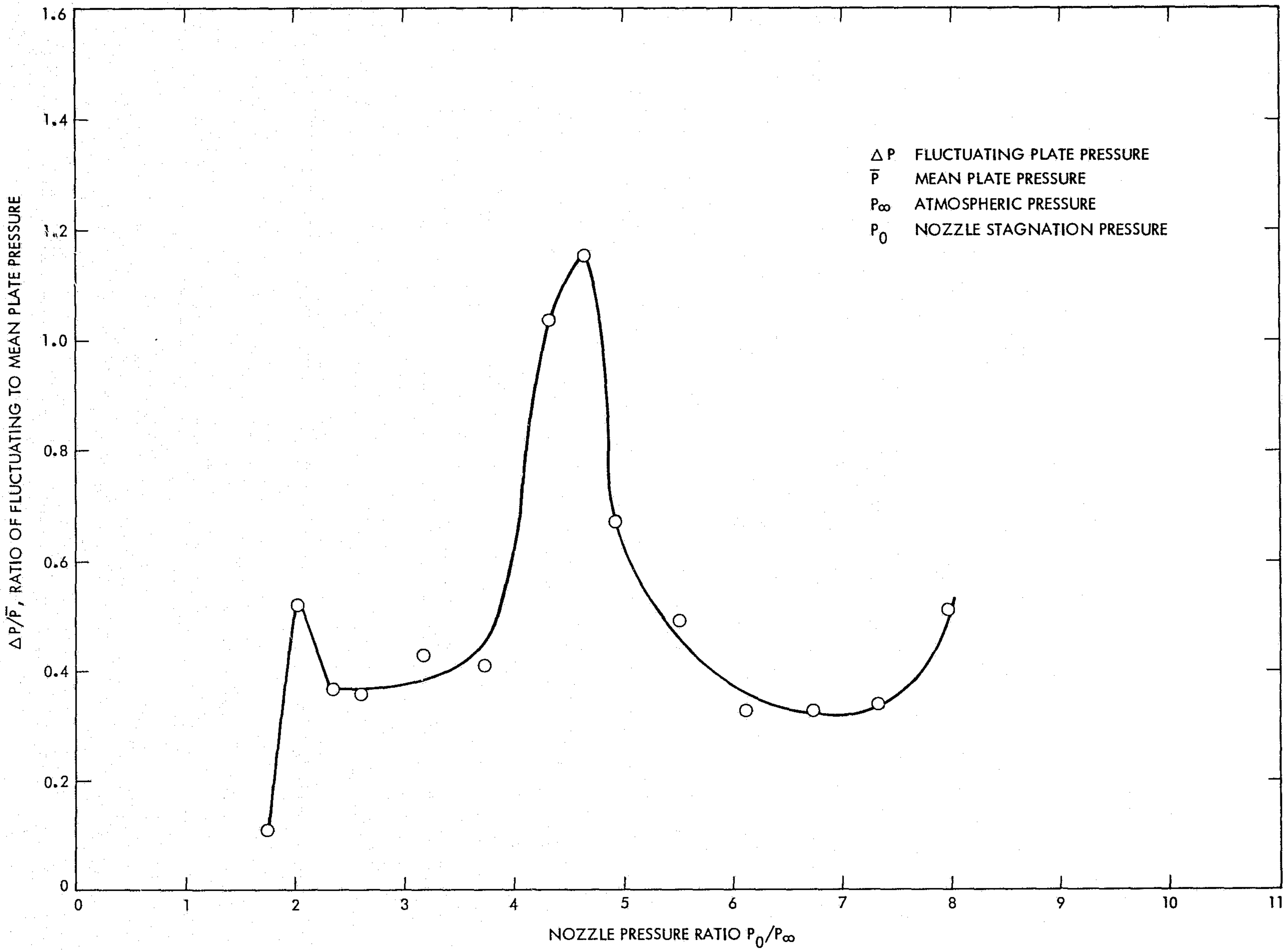


Figure Q-4. Ratio of Plate Fluctuating to Mean Pressure for different Nozzle Pressure Ratios R with Spacing $\frac{s}{d} = 1.5$

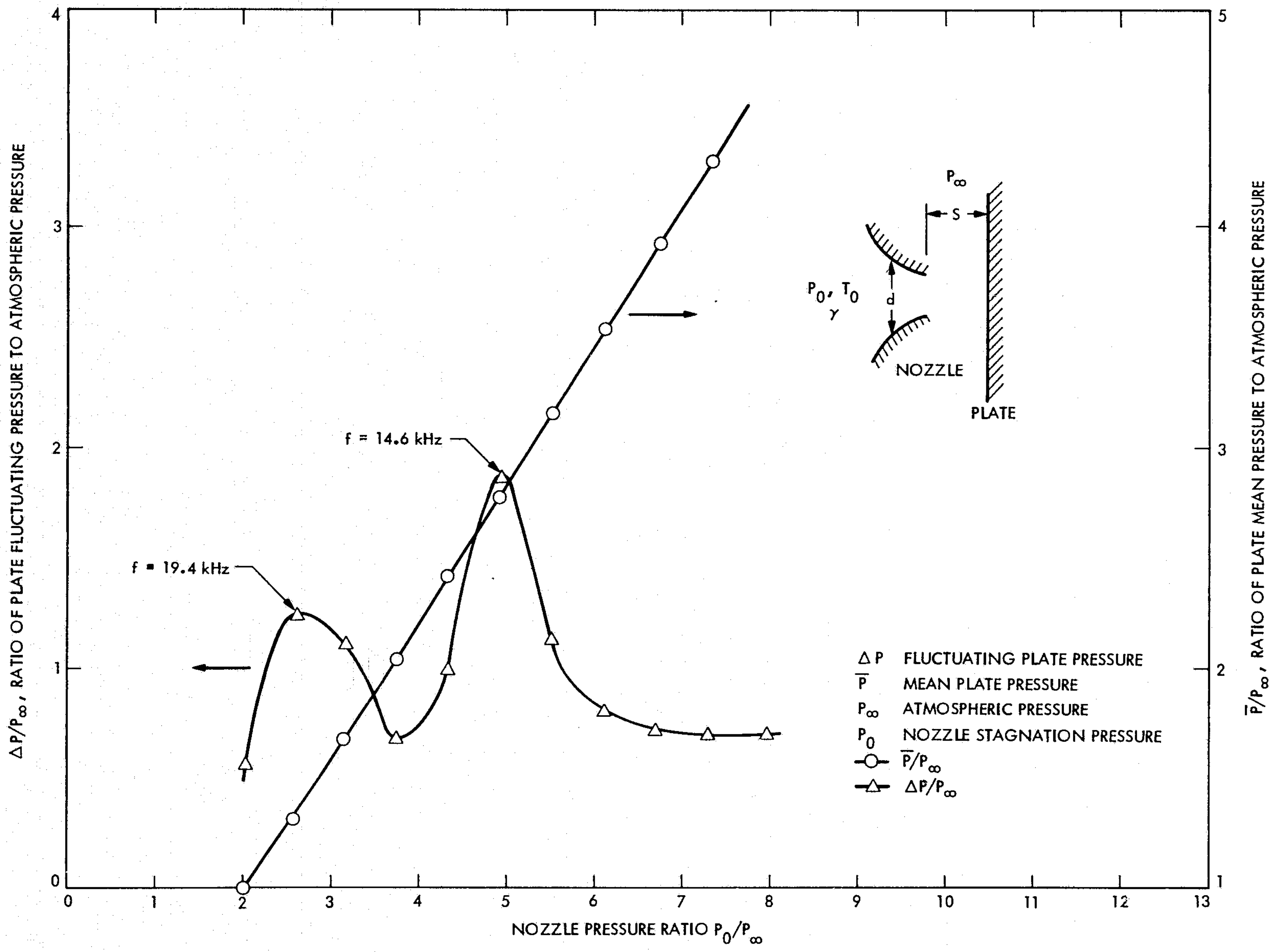


Figure Q-5. Ratio of Plate Mean and Fluctuating Pressures to Atmospheric Pressure for Different Nozzle Pressure Ratios R with Spacing s/d = 1.0

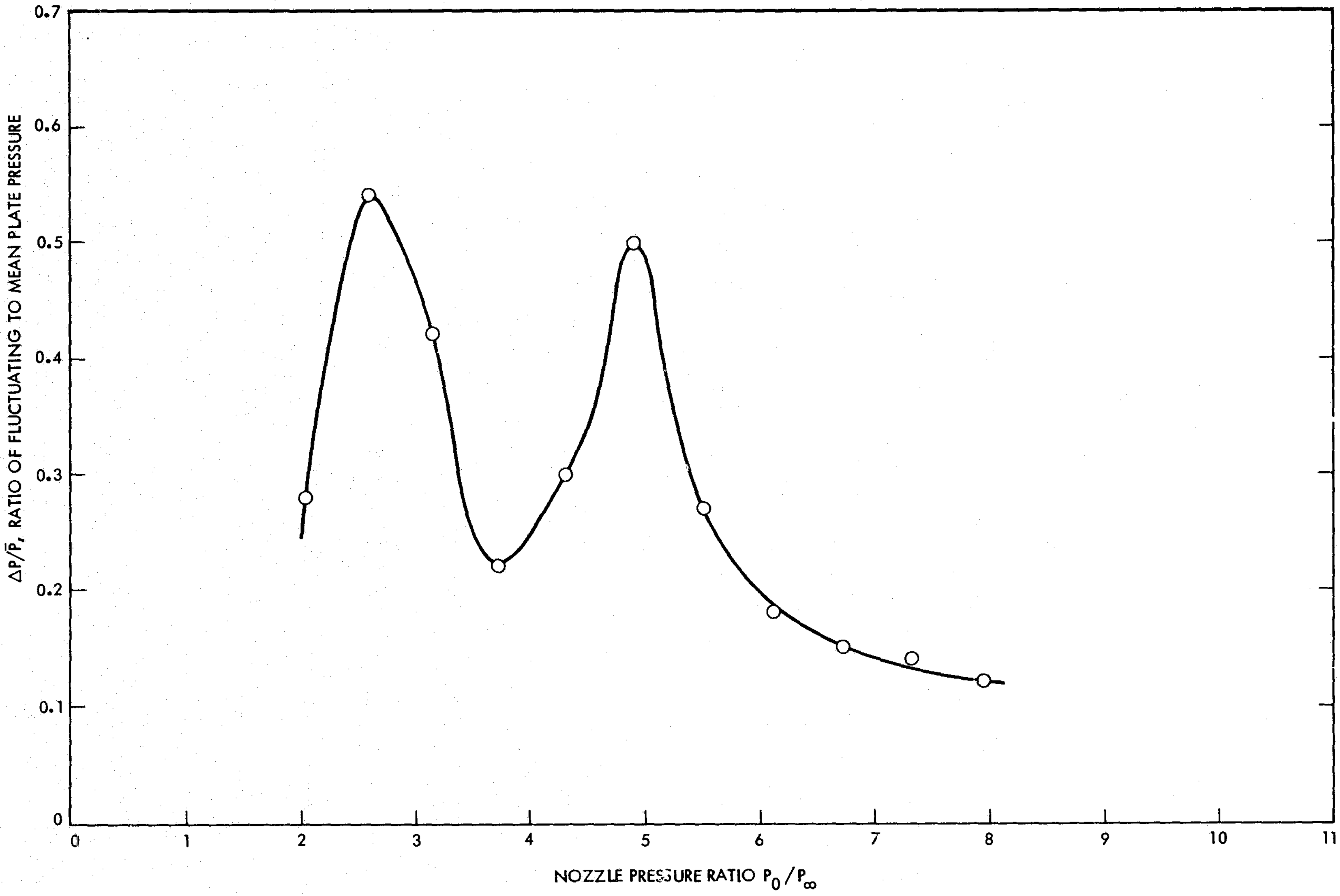


Figure Q-6. Ratio of Plate Fluctuating to Mean Pressure for Different Nozzle Pressure Ratios R with Spacing s/d = 1.0

Placement of the plate in the vicinity of the first shock cell in the free jet produced a spatial zone of instability therein, caused the shock wave to oscillate and resulted in periodic pressure pulsations on the plate. At the lower pressure ratio of about 2.5, the pressure fluctuations ΔP were less because of the interaction of relatively weak diamond shocks in the jet. As the nozzle pressure ratio was increased, the mean pressure $\bar{P}$ on the plate increased (Figure Q-2). At higher stagnation pressures in the flow, larger pressure losses occurred across the shock waves; i.e., the increase in plate rcovery pressure is not directly proportional to the increase in jet stagnation pressure. The local peak and then decrease in mean plate pressure at a nozzle pressure ratio of about 2.6 (Figure Q-2) was associated with the weaker diamond shocks in the jet changing to a stronger normal shock cell (Mach disc) as the pressure ratio was increased.

A measure of what the plate experiences; i.e. the ratio of pressure fluctuation ΔP to mean pressure on $\bar{P}$ the plate, is shown in Figure Q-4 with spacing s/d = 1.5. The magnitude of the pressure fluctuations were relatively large; at the first peak, $\Delta P/\bar{P}$ was about 0.5, and at the second peak, $\Delta P/\bar{P}$ was more than 1.0.

Pressure data obtained with a smaller plate spacing of s/d = 1.0 are shown in Figures Q-5 and Q-6. For the first peak the pressure fluctuations were about the same as for the larger spacing, but for the second peak, the pressure fluctuations were less by 0.5 (cf. Figures Q-4 and Q-6). This was due to the smaller amplitude of the standing shock wave oscillations and less pressure loss across the shock (higher P) for the smaller spacing.

IV. ROCK STUDIES

The device in a resonance tube configuration was used with sandstone and bituminous coal samples. In the sandstone sample (Figure Q-7), a 3.0-cm dia. hole, 7.6 cm deep, formed the resonance cavity, the thickness of the sandstone endwall being 3.8 cm. The coal sample formed the endwall of an attached metal tube 3.0 cm inside dia. and 7.6-cm long. The mouths of the sandstone sample and the metal tube with coal endwall were located at a spacing s/d = 2.0 from the nozzle exit.

With the coal sample, the resonance tube drill was operated first in the jet regurgitant mode in which the jet was periodically swallowed and expelled by the tube. In this mode of operation, the nozzle pressure ratio was increased to about 4.9 for about 1 minute. The tube resonance frequency was 0.95 kHz. No damage to the samples was observed. The device was then operated in the jet screech mode by increasing the nozzle pressure ratio to 6.7. In the jet screech mode, a shock wave stood between the nozzle and tube inlet and oscillated in various bands of frequencies. For the present test at a pressure ratio of 6.7, the shock oscillation frequency was 3.5 kHz.

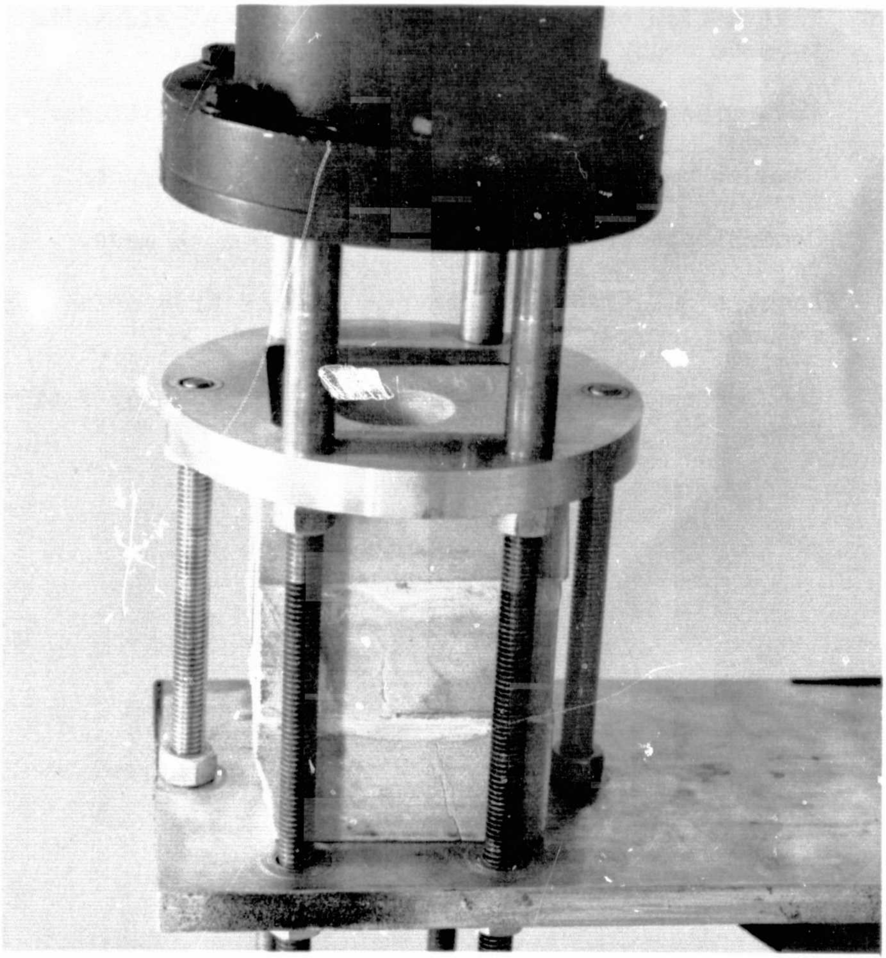


Figure Q-7. Sandstone Sample with Resonance Cavity

Large cracks occurred in the endwall and sidewall of the sandstone sample (Figures Q-8 and Q-9). Smaller cracks appeared after 15 sec of operation and the larger cracks occurred after about 45 sec. For the coal sample, after about 10 sec, pieces of coal broke off, and the jet was turned off after 30 sec. The coal sample whose seams were normal to the flow was completely cracked parallel to a seam, had multiple cracks normal to seams, and the endwall was cratered to a depth of about 1 cm by the oscillating tube flow. Further inspection of the coal sample is required to determine whether failure occurred because of the pressure pulsations or thermal stresses or both. The exact time to failure also was not known.

C-2

V. SUGGESTED FURTHER TESTS

The preliminary tests have indicated that the resonance tube drill is capable of breaking rock. Further tests could consist of the following:

1) Construct resonance tubes of variable length to vary the frequency of pressure pulsations in rock studies.

2) Take motion pictures through transparent sidewalls of a resonance tube to study the rock fracturing process.

3) Test other rock samples and geometric conditions.

4) Conduct tests at elevated surrounding pressures.

5) Demonstrate drilling through a large rock mass.

6) Acquire quantitative measures of rock fracturing and drill performance.

7) Conduct tests to determine the high-frequency fatigue properties of rock.

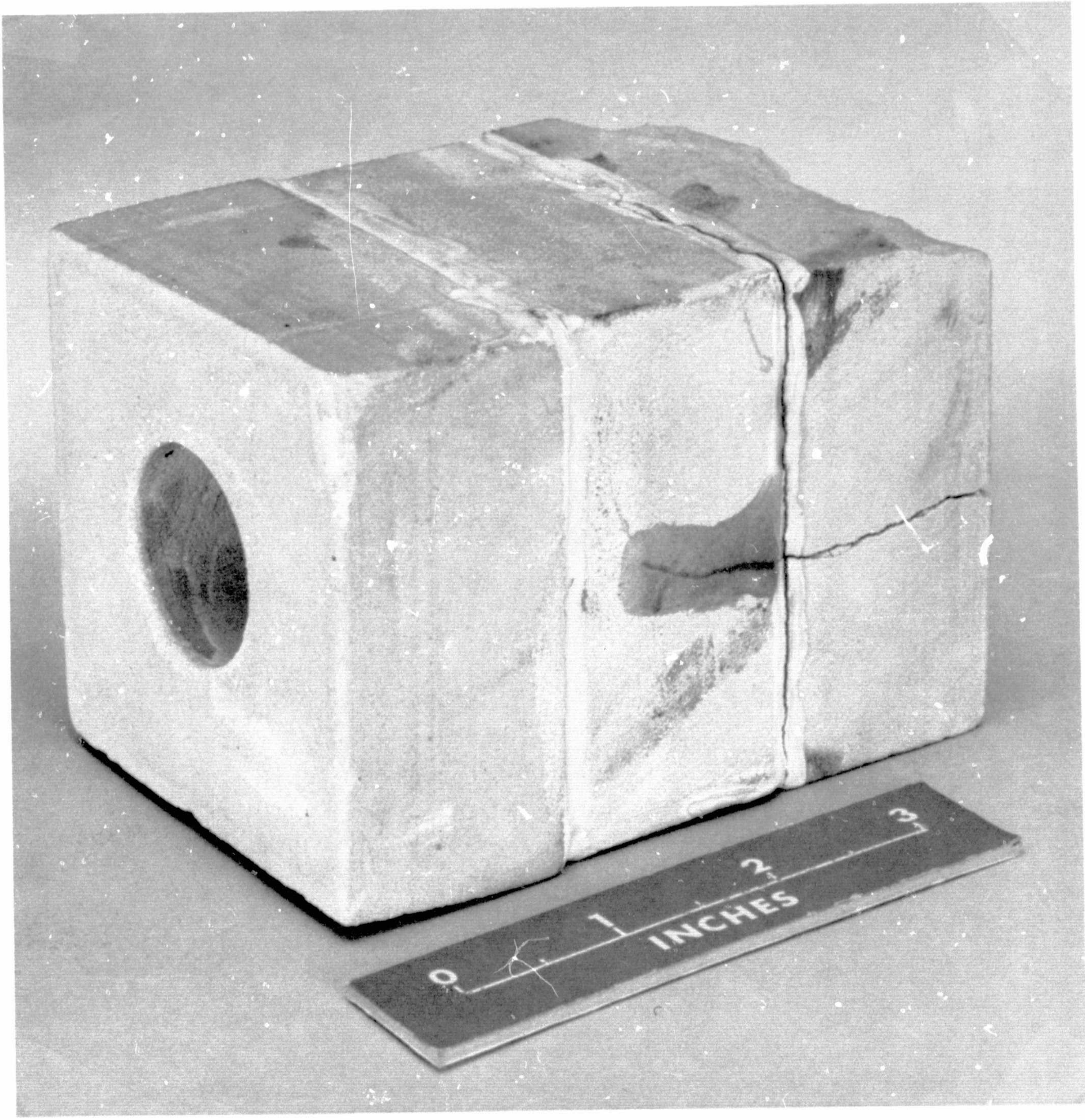


Figure Q-8. Sandstone Sample, Jet Screech Mode, Showing Cracks in Sidewall

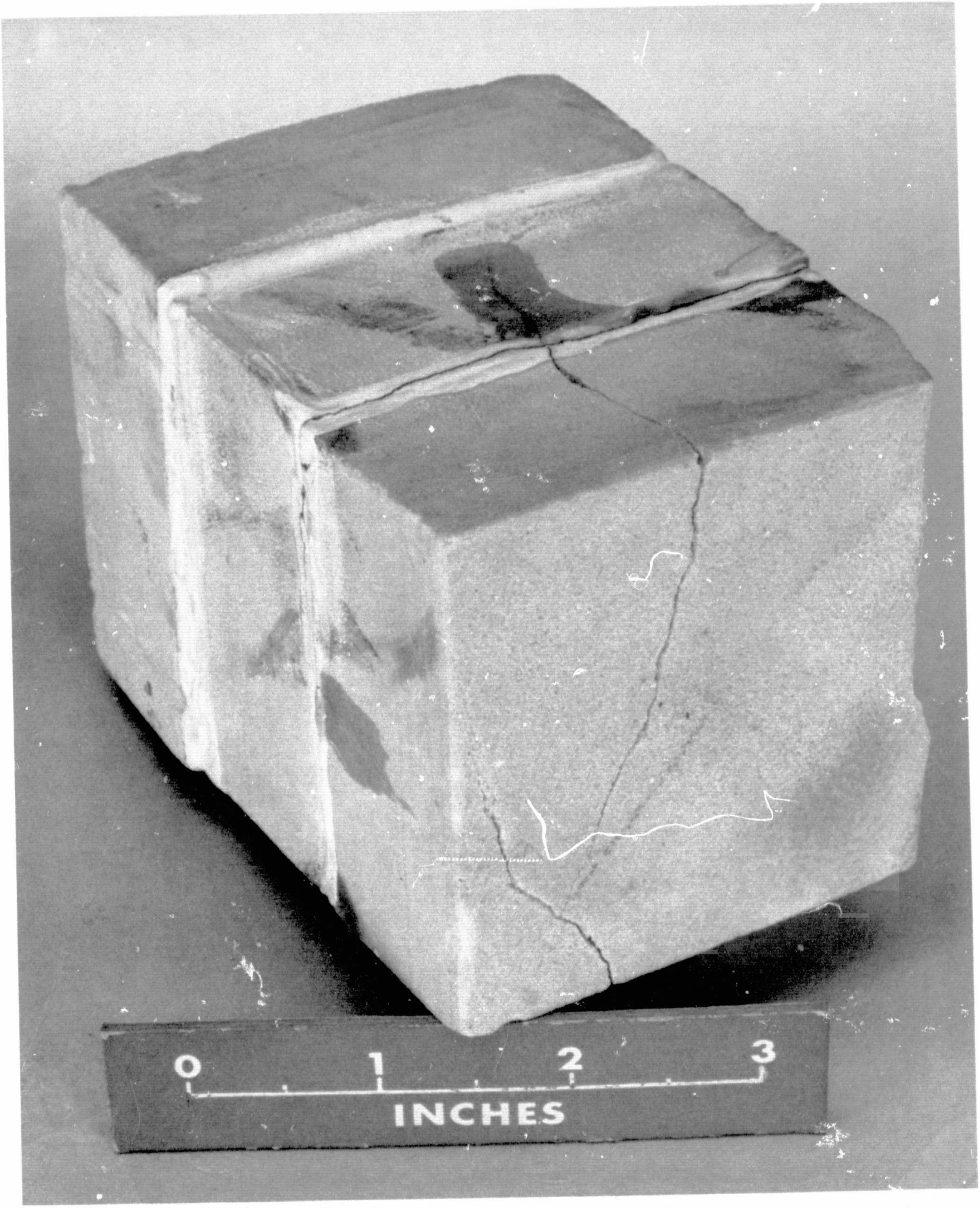


Figure Q-9. Sandstone Sample, Jet Screech Mode, Showing Cracks in Endwall

APPENDIX R

TECHNICAL DETAILS ON GEOCHEMICAL EXPLORATION FOR SUBSURFACE PETROLEUM BY REMOTE SENSING OF ATMOSPHERIC IODINE

I. INTRODUCTION

The purpose of this Appendix is to elucidate the subjects outlined briefly in the main body of the report in greater detail and to provide a broader background to the geochemistry of iodine. Information on the geochemistry of iodine is very limited. Most of the reported work focuses on iodine in waters (especially, subsurface brines) and its association with marine organisms (e.g., algae). There is surprisingly little iodine data on petroleums, organic matter in sediments, sedimentary rocks and minerals, igneous and metamorphic materials, or the atmosphere. For the most part analytical work has not been designed to elucidate the molecular or ion state of the iodine, i.e., iodide, iodate, elemental iodine, organic complexes, etc.

First a brief discussion of some of the pertinent aspects of the general geochemistry of iodine will be reviewed. This is followed by the examination of several specific questions and problems which are of direct importance and pertinence to the iodine prospecting method.

II. SELECTED REVIEW OF IODINE GEOCHEMISTRY

The most adequate summaries of the geochemistry of iodine are those by Rankama and Sahama (Ref. R-1)* 1950, Goldschmidt (Ref. R-2) 1954, and Correns (Ref. R-3) 1956. These constitute the chief source of the abbreviated review presented below.

The average abundance of iodine in meteorites and igneous rocks (i.e., "primary" earth materials) is 1 and 0.3 ppm, respectively. Iodine is a lithophile element like the other halogens, but it also displays significant atmophile and biophile behavior. It is strongly oxyphile and is notably concentrated in the hydrosphere, e.g., sea water and subsurface waters. It is possible that iodine, along with other halogens, was a significant constituent of the primordial atmosphere and subsequently entered the early hydrosphere.

More specifically, Goldschmidt (1954) recognizes several important processes of iodine concentration:

1) The biochemical concentration in marine plants and animals.
2) The biochemical concentration in the thyroid gland of terrestrial animals, including man.
3) Concentration in soils.
4) In peats, lignite, and coal.
5) In sedimentary phosphate.
6) In iodides of copper and silver in oxidation zones of ore deposits.

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*References are listed at the end of this appendix.

7) As the iodate ion, IO_3, in the nitrate deposits of Chile.
8) In some natural mineral waters, especially in geological association with accumulations of mineral oil.

The average content of iodine in sea water is 0.06 mg/l (Goldberg, 1965, (Ref. R-4). According to comparisons made by Correns, the iodine concentration in sea water is nearly 30 times as great as that in river water. Much of the iodine of river waters probably does not originate directly from weathering, but is precipitated along with rain water from the atmosphere. It seems evident that much of ocean iodine is recycled via the atmosphere. Mason (Ref. R-5, 1966, p. 221) cites that iodine is universally present in the atmosphere in small variable amounts and gives the iodine content of rain water as ranging from 0.002-0.0002 mg/l. Others report the following concentrations of iodine in the atmosphere:

0.1 to 1.4 $\mu g/m^3$	Correns, 1956, p. 208
0.005 ppm	Rankama, 1950
0.0001-0.001 mg/m^3	Rankama, 1950, p. 307
0.0001-0.0015 ppm., av. 0.0005 ppm	Goldschmidt, 1954
and	
0.001-0.003 ppm (rain water & snow)	Goldschmidt, 1954

Most workers agree that the oceans are the principal source of atmospheric (airborne) iodine. Other likely sources include industrial pollution (burning of fossil fuels), release of iodine during the production of the element by ashing of seaweeds, volcanic emanations, and from subsurface mineral waters, e.g., brines, expelled from springs. The precise mechanism of iodine transfer from sea water to the atmosphere is not well established. Likely possibilities include (1) incorporation of sea spray (foam, droplets, fog) into the atmosphere, and (2) oxidation in the surface zone of the oceans of iodide to elemental iodine which is liberated to the atmosphere in gaseous form. The general observations that the content of iodine is higher in air masses of marine origin compared to continental, that the iodine content of rain water decreases with distance from the ocean, and similarly that the iodine content of soils (probably mostly from rain water) decreases with distance from the coast (Ref. R-2), support the conclusion that the oceans are the major source of air-borne iodine.

Some controversy exists regarding the state of iodine in the atmosphere. Goldschmidt (1954, Ref R-2, p. 608-611) discusses the problem and concludes that atmospheric iodine probably includes both free gaseous iodine molecules and iodine adsorbed or attached to airborne dust particles. He speculates that a state of equilibrium may exist between the two forms and that where large amounts of atmospheric dust are present gaseous iodine molecules may be virtually absent. This is an important consideration with regard to prospecting methods for atmospheric iodine. If iodine is concentrated on dust particles, spectral analyses may be useless, but collection and analyses of dust particles (e.g., by Barringer Airtrace system, Ref. R-6) might be very applicable.

The biophile character of iodine is best displayed by its well known enrichment in marine organisms. As summarized by Goldschmidt (1954, Ref. R-2, p. 607), the iodine contents of important algae and other organisms are as follows:

	Iodine ppm dry wt.
Brown algae	100-4000, rarely 7000
Red algae	10-1000
Green algae	10-1500
Plankton	up to 620 ppm
Fishes	1-30 ppm

Land plants contain less iodine than freshwater plants, which in turn contain less than marine plants. Nevertheless, Goldschmidt points out that lignites, peats and coals may concentrate iodine (perhaps by chemical fixation from circulating solutions). He cites two analyses:

peat	12-40 ppm I
coal	1.6-11 ppm I

Although this is not well documented, Vinogradov (Ref. R-7, 1953, p. 92-94) speculates that iodine in organisms (esp. algae) may occur as HI, KI, organic molecules, and iodo-organic compounds. An important point is that much of the iodine in organisms is in a water-soluble state.

In general, iodine is enriched in soils relative to the igneous bedrock from which they are derived. Typical soil iodine contents range from 0.6 to 8.0 ppm and average near 2 ppm (exceptional values are as high as 10-70 ppm). This compares with values of 0.2-0.4 ppm (av. 0.3 ppm) for common igneous rocks. Enrichment is highest in the uppermost layers of cultivated soils. It seems unlikely that the soil iodine enrichment is due to the concentration of residual iodine compounds of weathering origin because most iodine compounds are highly soluble. More likely, the soil iodine comes from the extraneous source of airborne iodine via rain water or snow. Fixation of the iodine by absorption by soil-humus in the uppermost portion of the soil seems most logical. It is emphasized that any surface petroleum prospecting using an iodine method should give due consideration to the data and genetic problems involved in soil iodine geochemistry.

Goldschmidt (see Rankama, 1954, Ref. R-1, p. 768) makes a rough estimate of 0.8 ppm as the average iodine content of sedimentary rocks. Available information clearly demonstrates that carbonaceous (esp. bituminous) and phosphatic sedimentary rocks and many coals are comparative rich in iodine. Among the nonphosphatic sedimentary rocks, shales (i.e., marine hydrolysates) display the greatest iodine enrichment. However, it is generally thought that the concentration in these sediments is controlled by the commonly associated organic matter rather than by the inorganic mineral fraction, i.e., clays. This was rather well demonstrated by the work of Wilke-Dörfurt (1927) (reported by Correns, 1956, Ref. R-2, p. 216-217); for oil-shales as the oil content rose from about 1.5 to 6.25%, iodine content increased from 0.2 to 2.0 ppm. Similar results were obtained more recently by Walters (Ref. R-8, 1967). Marine phosphate sedimentary rocks range from 1 to 1000 ppm iodine (Goldschmidt, 1954, Ref. R-2, p. 619) generally between 10 to 100 ppm. As phosphate-rich sediments are also rich in marine organic matter, it seems likely that their high-iodine content is through the agency of the carbonaceous material rather than the phosphate component. Specifically, it is probable that high iodine in sediments and sedimentary rocks is controlled by the accumulation of the remains of marine algae which concentrate iodine during their life cycle.

Somewhat surprisingly, the iodine content of evaporite is low. Goldschmidt (1954, Ref. R-2, p. 620) reports values for anhydrite, rock salt, and potash salts ranging from 0.005 to 0.2 ppm. In similar rocks, Correns (1956, Ref. R-3, p. 222) summarizes data ranging from nil to about 0.1 ppm. Goldschmidt suggests that the low-iodine contents are due to its loss from the brine to the atmosphere during evaporation. A likely alternative is that because of the large difference in ionic radius of I^- (2.16Å) compared to Cl^- (1.81Å), it cannot substitute in chloride salts and consequently is enriched in the residual solutions (bitterns) and does not accumulate with the evaporite solids.

Krejci-Graf (Ref. R-9, 1963) (also quoted in Rankama, 1950) suggested that the source of the iodine was from the same organic matter, e.g., marine algae, from which the petroleum was generated and that the brines could be viewed as a product of the petroleum formation process. Specifically, he suggested that during petroleum genesis the organic matter decomposed yielding much of its indigenous water and iodine to form the brine. White, Hem, and Waring (Ref. R-10, 1963) present 33 analyses of oil-field waters. Iodine concentrations range from less than 0.1 ppm to as high as 199 ppm. In 42 California oil-field waters, Gullikson, Caraway and Gates (Ref R-11, 1961) report iodine values ranging from nil to 61.0 mg/l. Hitchon, Billings and Klova (Ref. R-12, 1971) compute the mean iodine values of formation waters from the western Canada sedimentary basin at 9 mg/l. Exceptionally high-iodine concentrations ranging from 8 to 1400 mg/l were reported by Collins (Ref. R-13, 1969) for Anadarko basin brines. Although no statistical compilation has been made, Collins and Egleson (Ref. R-14, 1967) state that most oil-field brines contain less than 10 ppm iodine; some approach 100 ppm, but few contain more. Schoenreich (Ref. R-15, 1971) reported 2 mg/l for brines from the Pomeranian anticline; Bojarkski (Ref. R-16, 1966) 7-9 mg/l for brines from the Pomeranian syncline. In brines from oil and gas fields in Japan and Okinawa, Sudo (Ref. R-17, 1967) and Motojima (Ref. R-18, 1971) found 12-34 mg/l or more of iodine, in Japanese mineral springs and brines from non-oil regions, an average of 0.2 mg/l (Sudo).

In virtually all cases, the brines display iodine enrichment factors (compared to sea water) varying from 20 to as high as near 30,000. Similarly I/Cl ratios of brines are consistently much higher than in sea water. Clearly, if, as most workers suggest, sea water is the parental fluid for subsurface oil-field brines, then brine genesis and evolution involves a significant absolute and relative increase in iodine content. Contributions from marine organic sources, which might also be linked to petroleum evolution as the primary hydrocarbon sources, remain a most plausible explanation.

III. GEOCHEMICAL NEXUS BETWEEN IODINE AND PETROLEUM

A. ASSOCIATION OF IODINE WITH PETROLEUM

For an element (or substance) to be useful as a direct prospecting indicator for petroleum, one might logically require that the element occurs somewhat consistently in high (anomalous) concentrations in petroleum.

Therefore, it is pertinent to examine the iodine content of petroleum and evaluate whether or not such values would correspond to anomalous highs compared to typical adjacent materials.

The iodine content of petroleum ranges from extremely low to low values (see Table R-1). In comparison to oil-field waters, petroleums are much subordinate in their iodine content. Thus, it seems unlikely that we can expect surface iodine anomalies directly related to crude oil iodine contents. If surface anomalies are to be expected over petroleum accumulations, they must be related to other iodine-rich but petroleum-associated materials such as subsurface brines.

This conclusion is supported by experimental work cited by Nikanorov (Ref. R-21, 1971 and Ref. R-19, 1976). Specifically, iodine absorption experiments with various hydrocarbons and petroleum showed that these "lipid-like substances can actively absorb only free iodine and practically do not absorb iodides." Briefly stated, the experimental results account for the suggested generalization, cited above, that oil-field waters are strongly enriched in iodine compared to petroleum. Further Nikanorov concludes that "since iodine in free form is not encountered in the reducing conditions of sediment accumulation basins, it is obvious that iodine enriches rock and later the underground water primarily due to iodides absorbed by organic-mineral mixtures." Similarly, Nikanorov concludes that "an elevated content of iodine in stratal water cannot serve as a direct indicator of oil and gas," but, "iodine must be considered among the indirect hydrogeochemical indicators ...."

B. ASSOCIATION OF IODINE-RICH BRINES WITH PETROLEUM

Some persons have speculated that high-iodine brines are consistently associated with petroleum and hence might be used as a petroleum indicator. This reasoning implies that there are many subsurface (saline) waters which are low in iodine and are unassociated with petroleum accumulations. With perhaps only one exception, the literature on this topic does not make a clear (and statistical) distinction between true oil-field brines, i.e., waters in direct physical association with petroleum and reservoir waters which are demonstrably <u>not</u> directly associated with petroleum. This is probably and chiefly because producing oil fields have provided the most abundant and ready source for water samples.

There seems little doubt that iodine <u>is</u> virtually ubiquitous and quantitatively a significant <u>minor</u> constituent of oil-field waters. However, its extent of enrichment and concentration as reviewed above varies extensively from common values of 10-30 ppm to unusual concentration of 100 to 1500 ppm. How high must the concentration be in order to "indicate" oil? Does the likelihood of a direct indicator increase with the more extreme iodine concentrations? Karstev et al.(Ref. R-22, 1959, p. 242-43) regard iodine in water as "an important and well-known indicator of petroleum." They observe that a concentration of 5 mg/l (near 5 ppm) is close to the maximum observed in "non-oil-bearing regions" and assume that "an iodine content greater than 5 mg/l under any conditions is a positive indicator of petroleum." However, they hedge and indicate that depending upon "different conditions" lower iodine values may also be indicative of petroleum.

Table R-1. Association of Iodine with Subsurface Brines

Sample	Iodine, ppm	Source	Remarks
Anadarko Basin, Oklahoma	0.05	Collins & Egleson, 1967 (Ref. R-14)	Sensitivity 0.05 ppm
Mont.-Wyo.			
376-418°C fract.	0.31×10^{-3}	Walters, 1967 (Ref. R-8)	
Residue	2.3×10^{-3}	Walters, 1967	
Mont.-Wyo.			
325-468°C fract.	0.55×10^{-3}	Walters, 1967	
Residue	0.78×10^{-3}	Walters, 1967	
Mont.-Wyo.			
323-464°C fract.	5.4×10^{-3}	Walters, 1967	
Residue	0.46×10^{-3}		
Ciscaucasia	10	Nikanorov, 1976 (Ref. R-19)	50 samples, av. only
Irkutsk Amphitheater Atovka, 2-r	20	Kudel'skiy & Kozlov, 1971, USSR (Ref. R-20)	
Osinskiy Horizon 1950-1983, 0.4 m	20	Kudel'skiy & Kozlov, 1971, USSR	
Caucasus Khodyzhensk	20	Kudel'skiy & Kozlov, 1971, USSR	
Urals area, Chusovskiye Gorodki	Not found	Kudel'skiy & Kozlov, 1971	
Sakhalin, Okha, stratum 4	Not found	Kudel'skiy & Kozlov, 1971	

Hitchon and Horn (Ref. R-23, 1974) deal with the problem in a more quantitative manner for the formation waters of Alberta, Canada. They found, by statistical discriminant analysis of 438 formations, that at the 95% confidence level the formation waters associated with producing intervals are chemically different in a multivariate sense (using the components chloride, bromide, iodide, bicarbonate, sulphate, calcium, magnesium, and sodium), from formation waters from nonproducing intervals. For the waters from Paleozoic formations, iodine was the most important discriminator; in contrast, it was not an effective discriminator for Mesozoic formation waters. For the waters, there is considerable overlap between iodine values in producing and nonproducing intervals (see Hitchon and Horn, Table II and Fig. 1). The waters from producing intervals of Paleozoic formations range in iodine content from less than 5 to about 55 mg/l (mean 12.7), waters from nonproducing sections range from less than 5 to 40 mg/l (mean 7.19). Similarly, the Mesozoic waters from producing and nonproducing intervals overlap in iodine content with average values of 10.8 and 7.50 mg/l respectively. Despite the overlap, note that in both the Palezoic and Mesozoic categories, the mean iodine values for the waters from producing zones are significantly higher. Hitchon and Horn surmise (at least for the Paleozoic water) that the source of the enhanced concentrations of iodine in producing formations waters is the organic matter in the sedimentary rocks from which the hydrocarbons originated.

The important significance of their results seems as follows. Combined with other components in a multivariate analysis, in some cases (e.g., Paleozoic), iodine is an important aid in discrimination of water from producing and nonproducing intervals. Nevertheless, when used as a single variable, iodine content does not discriminate between producing and nonproducing formation waters, i.e., note extensive overlap of iodine values in waters from producing and nonproducing intervals. Further, there is no clear or obvious concentration limit for iodine as a petroleum indicator. Finally, many barren, i.e., water-filled, reservoirs can be expected to contain waters with iodine concentrations in the same range as petroleum-associated oil-field waters; hence, direct petroleum prospecting using an iodine-method will probably not be able to discriminate between them.

C. SURFACE IODINE ANOMALIES - CONSIDERATIONS AND PROBLEMS

Assuming a subsurface concentration anomaly of iodine in either petroleum or associated brine, there are many problems related to its manifestation as a surface iodine anomaly. Most of the problems and complications are shared with the older surface petroleum prospecting methods. Hitchon (1974, Ref. R-24, p. 537) emphasizes the importance of fluid flow (related to fluid potential) in the near-surface region which may well control the path by which hydrocarbons and other constituents may be transported to the surface. Perhaps a positive point here is that such fluid movement may provide an effective transport mechanism, albeit leading to an anomaly perhaps widely displaced from the vertical position over the source. For field tests of the iodine prospecting method, it would be wise to select shallow petroleum reservoirs which are also well-known from a hydrodynamic standpoint. Perhaps "stagnant," i.e., hydrostatic fluid regimes where fluid flow might not be a serious problem should be selected for initial well-controlled field tests. Under stagnant conditions iodine might by ordinary solution-diffusion processes make its way from concentrated brines at shallow reservoir depths to the surface.

In the case of iodine in formation water, vertical transfer might be aided by chemico-osmotic effects where shales in sedimentary basins act as semipermeable membranes during the slow dewatering of the sedimentary pile undergoing compaction. The mechanism has been called "salt-sieving" because it permits the selective escape of water and concentration of the dissolved salts. Mobility differences among the ions help explain some of the compositional variations in membrane-filtered subsurface waters (White, Ref. R-25, 1965). White (1965, Ref. R-25, p. 351) cites evidence from water analyses that iodine (I^-) displays high mobility during membrane-filtration (compared to Cl^-) so that it would be enriched (esp. relative to Cl^-) in the filtered (effluent) waters. Perhaps iodine could be transported to the surface from an oil-field brine along fluid-flow paths across which shales were acting as membrane-filters and causing the selective relative concentration of I^- in the effluent surface-bound waters.

Care must be taken to distinguish valid subsurface indicators (i.e., introduced from depth) from indigenous or syngenetic iodine in a weathered bedrock or soil survey. For example, outcrop areas of iodine-enriched sediments, such as phosphorites or organic-rich shales, would be expected to display iodine anomalies. Similarly, some soils, which as discussed previously may be enriched in iodine from rain water sources, might also yield misleading "petroleum indicator" anomalies. From a methods testing standpoint, it is recommended that early field tests for the iodine method might be conducted over rocks and soils of established iodine enrichment. As an extreme case, the Chilean nitrate deposits should be considered. Their iodine concentrations are known to range from 200-1700 ppm (Rankama, 1950, Ref. R-1, p. 769).

Despite these serious and unresolved problems, Kartsev et al., (1959, Ref. R-22, p. 293) briefly refer to a soil-iodine method as a direct prospecting method for oil formations. They cite one Russian paper (Kovda and Slavin, Ref. R-26, 1951) on the subject which reputes to have observed iodine contents in the soil (i.e. soil-salts) of 10 to 100 ppm over "several oil formations" compared to "normal content" of 1 ppm. A group of eight iodine analyses of soils (cited by Ficklin, Ref. R-27, 1975) collected from the Cymric oil field in California seem to support a more conservative view. Mean iodine values were found to range from 1.4 to 12 ppm, the median value falling between 2.7 and 6.3 ppm. Although this is somewhat higher than the general average of soils (see the geochemical section), it is well within the range of typical soils. Without a careful sampling of background iodine value around and across the field, one cannot conclude that these values are indicative of an iodine anomaly.

The evaluation of Hitchon (1974, Ref. R-24, p. 543) based on "a careful evaluation of the literature on surface prospecting for petroleum," i.e., conventional methods, applies to the proposed iodine method as well. Specifically he concludes, "In regions with residual soils the technique may be feasible, provided the near-surface flow regime is adequately known. In view of the fluid nature of crude oil and natural gas, it is difficult to understand why geochemists have not been more concerned with the composition and flow of the near-surface and surface fluids and less with soil and weathered bedrock. It seems obvious that this should be the correct approach and until such a comprehensive study is undertaken, with rigorous statistical control, surface geochemical prospecting for petroleum on land will remain equivocal."

D. RELEASE OF IODINE TO THE ATMOSPHERE

Assuming concentrations (i.e., anomalies) of iodine in the soil or weathered bedrock over petroleum accumulations, the successful application of an airborne detection method is dependent on the release of elemental (free) iodine to the atmosphere. Iodine occurs in all of its three oxidation states in nature, i.e., I^-, I_2 and IO_3. Iodates are only found in settings of high oxidation potential such as the Chilean nitrate deposits. Most iodine probably occurs in the iodide form as a free ion, combined in salts, or combined with organic molecules, i.e., organic halides. In soils, it seems likely that iodine transported to the surface from iodide-enriched brines would be in the iodide state either as soil salts (see Kartsev, 1959, Ref. R-22, p. 293) or combined with soil organic matter (humus). Release to the atmosphere as free I_2 would necessitate an oxidation process. Among the halogens, iodide is the most readily oxidized, as judged by the standard oxidation potential for the half reaction

$$2I^- = I_2 + 2e^- \qquad -0.54 \text{ volts}$$

Consequently, I^- ion may be readily oxidized to I_2 by a number of common natural oxidizing agents which may occur within the soil-atmosphere environ. These include Fe^{+++}, NO_3^- (soil nitrates), O_2, Mn^{+++}, and O_3. Clearly, the oxidation of I^- to I_2 in the soil horizon seems very plausible. The process might be impeded in more reducing soils rich in organic matter. Once in the oxidized state, the high vapor pressure of I_2 virtually assures significant transfer to the atmosphere.

E. SUMMARY ASSESSMENT

Iodine concentration in oil-field brines may be related to a common general source for the iodine and petroleum hydrocarbons, i.e., the iodine-enriched marine organic matter (algae) of the petroleum source sediments. In this case, iodine content in subsurface waters may be an indirect (regional) indicator of possible petroleum productivity. It is possible that a localized iodine concentration could develop in an oil-associated brine after the formation of the oil pool by transfer of iodine from the petroleum to the surrounding brine. Such a transfer process would result in an iodine-depleted crude oil (as most seem to be) and an enriched brine. If the hydrologic conditions were stagnant, i.e., no fluid flow, and iodine diffusion within the brine was slow, the localized iodine concentration in the brine might persist long enough to generate a surface anomaly which would indeed be a direct petroleum indicator. However, this scenario is unlikely and at best, we can only view high-iodine brines as <u>indirect</u> petroleum indicators. This pessimism is supported by the "special observations" cited by Nikanorov (1976, Ref. R-19, p. 23) where he points out that in an oil field (undesignated) "concentration halos of iodine (and bromine) have not been recorded in the zone of the water-oil contact both in the oil portions of the segregation, and in the water-saturated portion of the section." He concludes that apparently "diffusion exchange of ions of iodine (and bromine) does not take place in the water-oil contact zone."

If (as seems unlikely) iodine concentration occur in the subsurface in direct association with petroleum, their manifestation as "halos" on the surface seems very untenable. The greater the reservoir depth the more unlikely. Besides the vicissitudes of hydrodynamics which may impede and complicate the vertical transfer of substances from the reservoir; the documentation of vertical transfer and the resulting halos is not adequate. This concern applies especially to the development of a surface concentration of a <u>minor</u> element such as iodine in brines (recall, although "enriched," it still occurs in only ppm quantities). Nevertheless, without specific observations, one cannot totally reject the possibility that in some cases (perhaps over big, shallow oil fields with exceptional iodine concentrations in directly associated brines and where stagnant hydrologic conditions prevail) vertical migration of iodine has occurred and would serve to develop an indicator surface anomaly.

If surface iodine anomalies are formed, the release of iodine to the atmosphere in its free state seems very plausible. Meteorologic factors and the rate of iodine release (no doubt controlled by the release mechanism) will determine the transient nature of the air anomaly. It seems evident that under many conditions, despite a significant surface (i.e., soil) anomaly, the related air anomaly might not be observed.

IV. DETECTION METHODS AND PROCEDURES

The various methods to be described in this section were uncovered by literature search, industrial contacts, and personal knowledge. We begin with descriptions of techniques for remote determinations of atmospheric I_2. The considerations here are based mainly on instruments of the type developed by Barringer Research Limited (BRL) of Toronto, Canada. The Barringer instruments operate by measuring the correlation of the absorption spectrum of the gas with the spectrum of the outside atmosphere. There are two separate designs used by Baringer for accomplishing this. Only these two of the methods listed below are capable of detecting atmospheric I_2 remotely.

A. CORRELATION SPECTROMETER - COSPEC

COSPEC (Ref. R-28) is a conventional grating spectrometer with a mask in the exit focal plane. Briefly, the spectrometer operates as follows. An incident light beam (either sunlight or light from a lamp source), which has passed through the region of the gas X whose presence is to be detected, falls on two oscillating refractor plates which displace the incident wavelengths a small amount in a cyclical fashion. The light is then dispersed in wavelength (λ) by a grating. The dispersed light passes through a mask whose function is to transmit certain wavelength intervals of the gas X's absorption spectrum, and to block out others. (The choice of this mask is outlined below.) The power as measured by a phototube for one position of the mask is say, P_1. Next, the mask is shifted in λ by a certain small spatial displacement Δ. The power now is P_2. The quantity $1-(P_2/P_1)$ is taken as a unique measure of the presence of X. Calibration cells of the gas are included. Thus, known spectra can be taken under similar conditions of incident light. The choice of the mask is determined experimentally. The absorption spectrum of the gas X is measured in the laboratory (if its spectrum is not already reported in the literature), and the slits of the mask are chosen to correspond to the spacing of the sharp absorption lines of X. Hopefully, this choice of mask will be unique to I_2 and not to other interfering gases (NO_2, H_2O, SO_2, O_3, et al.); otherwise, there could arise a false indication of correlation. The rapid shift of the refractor plates enables power to fall on the two slits under the similar incident light conditions and background interferences eliminating some errors. For iodine, a 12-slit mask was used (Ref. R-29) from 525.6 nm to 549.0 nm. The width of the slits was 0.4 nm and the refractor plate jump 0.6 nm. Spectral radiance is relatively flat in this region. There are few Fraunhofer lines and absorption of other gaseous pollutants (Ref. R-30). The sensor is calibrated both in the laboratory and in the field by means of heated cells of known I_2 optical depth.

The instrument is operated repetitively observing first through the mask corresponding to the absorption peaks of the gas of interest (correlating position), and then through the same mask corresponding to properly chosen absorption minima (anticorrelating position). A virtue of this method of obtaining the correlation is that the mask may be designed so as to reduce the chance of spurious detection arising from interfering gases. The noise level of the spectrometer can vary from 0.3 ppm-meter (passive mode) to 10 ppm-meter (downward-looking) depending on mode and light source (Refs. R-28 and R-31). The aircraft platform results show that the downward-looking noise level is 2-3 times greater than the sideways-looking noise level. The sensitivity of the latest (1976) version of this correlation spectrometer to I_2 concentrations is 1 ppm-meter in a laboratory environment and 10 ppm-meter in a field measurement (Barringer, private communication, 1976). The difference is due to noise in the background skylight. Changes in the spectral gradient can also cause error signals in the correlation spectrometer. The latest Barringer designs carry a third channel to correct for the variation of spectral gradient. This compensation is carried out for both the COSPEC and GASPEC; the latter is described in the following section.

B. GAS CELL CORRELATION SPECTROMETER - GASPEC

The GASPEC (Ref. R-32) instrument does not employ a dispersing element (grating) but looks for a correlation between the observed absorption spectrum of the atmosphere and one produced by an appropriately chosen amount of gas in a sample absorption cell. It is expected that there will generally be some advantages in sensitivity for the GASPEC as the effective spectral resolution is closely related to the width of the lines in the sample cell. These will ordinarily be much narrower than the resolution of the grating correlation spectrometer. In the case of I_2, the density of the rotational lines is so high that the spectrum of the sample gas at atmospheric pressure may be quite blended and there may not be much advantage to the high resolution. Detracting from the ability to make simultaneous comparison is the fact that it is not possible to eliminate absorption from possible interfering gases if they fall within the band being used for the correlation.

The low sensitivity of the correlation spectrometer requires that it be operated in a horizontal and slightly downward looking mode in order to obtain a path length through a relatively dense I_2 region. Because I_2 gas is heavy and photodissociates and tends to adsorb onto aerosol, we cannot expect an extensive vertical distribution. To obtain a long path length through the atmospheric I_2, it is necessary for the aircraft to fly low and look horizontally. Barringer claims (private communication, 1976) that his measurements indicate the I_2 anomalies as measured in the surface soil are very much localized with horizontal distributions of the order of 10's of meters. The distribution in the atmosphere would be more highly dispersed and must depend on the local meteorology, but the I_2 anomalies may not survive longer than a few km. This indicates a limiting sensitivity of $\sim$5 ppb unless there are several sources in series in the line of sight. Junge (Ref. R-33) suggests that the background atmospheric I_2 concentration is variable and may be as low as 0.01 ppb. He also suggests that the atmospheric iodine content may be associated with I_2 adsorbed on the aerosol.

C. LASER-INDUCED FLUORESCENCE SPECTROMETER

An active device used in a static mode will exhibit a much greater sensitivity (Ref. R-34) to small atmospheric concentrations than the correlation spectrometer would be able to achieve. An atmospheric monitor (Ref. R-35) with a detectability of 0.9 ppb v/v utilizing a compact He-Cd laser at 442 nm for excitation of the NO_2 molecules in the atmosphere is available. This instrument has a linear response over about two decades of range; while the response of the correlation spectrometers may, in fact, be double-valued. Photon counting techniques are employed to detect the NO_2 fluorescence transmitted through a bandpass liquid solution filter that does not fluoresce upon absorption of scattered laser light. A counting time of 100 sec is mentioned for the lowest concentration measures (0.9 ppb v/v). The signal-to-noise ratio and hence the sensitivity will vary as $\sqrt{\tau}$ where τ is the integration time for photon counting. The active spectrometer must take samples of air and pass them through the specially designed fluorescence cell in order to achieve such high sensitivity. This means that it cannot be used as it stands as a remote sensor.

One can conceive that the active device could be made to work as a remote sensor by looking at the fluorescence through a telescope. The sensitivity here is limited by the energy of the laser and the efficiency of the detector optics including the integration time for photon counting. Furthermore, there will be increased analysis problems because of interference from aerosol and background fluorescence, not to mention a reduction of the measured fluorescence flux because of the range. The preceding considerations seriously limit the range to which this device would work, and the sensitivity of the state-of-the-art device probably is not as high as the correlation spectrometer. It does seem reasonable that an instrument could be developed which could sensitively and accurately make ground-based in-situ measurements of I_2 concentrations. For this method, the atmospheric quenching of the fluorescence could be quite strong and there is an appreciable probability of photodissociation. It seems possible, that the I_2 could be frozen out in a dry ice or LN_2 cold trap. The air pressure could then be reduced and the I_2 allowed to evaporate. This would possibly enhance the fluorescence and increase the sensitivity of the method. This method of concentrating the sample is used by mass spectroscopists.

D. PLASMA-JET SPECTRUM ANALYZER

This instrument has the merit that all the iodine in the air sample, in whatever chemical form it appears, is measured; also, the emission from many species (not only iodine atoms) may be detected. Thus, a "fingerprint" made up of emission from several species over the oil field could be established. The method has the disadvantage that the sample must be taken back to an analytical laboratory.

Barringer claims that the surface material, which is converted to aerosol and can be analyzed by his Airtrace (Ref. R-6) method, somehow reflects the below-surface chemistry and that an analysis of surface elemental content can be used as a petroleum indicator. He further contends that the mechanism for transport of iodine and other elements from the brine to the atmosphere seem to involve cracks in the lithology, and because these important correlating elements originate in the brines associated with oil fields, the water of hydration is an important part of the analysis. The Barringer plasma-jet spectrum analyzer, called the Airtrace, samples aerosol immediately above an oil/gas field and can be operated from an aircraft. The instrument is selective in aerosol size; it samples only aerosol particles larger than micron size. This is done to eliminate a lot of the background material which may not reflect the local surface. Further, the instrument has a mode of operation which Barringer claims allows it to sample specifically locally produced aerosol which are produced by local vortices picking up a puff of dust from the surface. This puff is detected in the Airtrace instrument by a sudden localized change of temperature or by a sudden localized change of optical density of the aerosol. The instrument collects all of the dust on a sticky tape but separates out the vortex-produced puffs on a separate place on the tape. The tape is then taken back to the laboratory and zapped with a CO_2 laser which volatizes the material collected on it (but not the tape which has been carefully selected to be transparent to the laser radiation). The volatized material is carried to a plasma jet by a stream of inert gas. There is is optically excited, and the resulting emission is analyzed spectroscopically. The method allows for the analysis of about 25 elements, including iodine, in picogram amounts. One picogram of iodine in 10 cm^3 of air is ~2 ppb v/v. Barringer feels (private communication, 1976) that this method could also be used to analyze iodine in air by bypassing the laser stage although it has not been used this way. By selectively zapping the aerosol particle with controlled intensity of the CO_2 laser, it is possible to determine the amount of the water of hydration.

E. LASER - ABSORPTION SPECTROSCOPY

It is possible (Ref. R-36) that laser radiation can be channeled so that it oscillates at a series of frequencies corresponding to the I_2 absorption maxima (or minima for the anticorrelating position). This would make the device a sort of laser correlation spectrometer for contained samples. The multipass absorption cells may be made of small volume and very long path (~ 10^2 meters), provided that a laser source is used. The sensitivity of this method is probably ~ 10 ppb. This method suffers from the disadvantage that only I_2 is measured.

F. MASS SPECTROMETRY

There are sensitive yet portable mass spectrometers (Ref. R-37) which can sample gases at atmospheric pressure. The gas chromatograph/mass spectrometer can measure all the iodine present independent of its chemical form. Because of its high-mass number, the background noise level would be low for iodine. The sensitivity is in the range of 10 ppb. This can be improved with some preprocessing of the air sample (e.g., use of a cold finger), but even so, the measurement requires an integration time of, at least, several seconds. Like the flame spectroscopic technique, the mass spectrometer measurements would give evidence of the presence of a "fingerprint" of the pertinent atmospheric species over the oil fields. Measurements would give evidence of the presence of chemical species other than iodine as well (long-chain hydrocarbons, He, bromides, to name a few). Moreover, the relative abundance of carbon isotopes can indicate whether compounds were formed very recently or not.

G. OPTO-ACOUSTIC DEVICE - SPECTROPHONE

A device called the spectrophone (Ref. R-38) is capable of measuring I_2 concentrations in the 1 ppb range. This device requires a strong tunable dye laser. The pressure pulses in a closed cavity arising from absorption of chopped laser radiation are sensitively detected with a microphone. The output is linearly proportional to the quantity of absorber for low concentrations. Several petroleum service companies are using spectrophones in soil gas analysis for hydrocarbon detection.

H. LASER CAVITY Q-MODULATORS

Extremely small amounts of absorber can be detected by inserting them in the cavity of a marginally oscillating laser (Ref. R-39). The sensitivity of this type of instrument (Ref. R-40) is probably better than 1 ppb for I_2; however, the output is nonlinear, and the instrument is not stable.

I. NEUTRON ACTIVATION ANALYSIS

Much work has been carried out in the area of stratospheric halogen measurement using the technique of stratospheric capture of the particular gas followed by neutron activation analysis. In the work of Lazrus, et al. (Ref. R-41), samples of air were drawn through alkaline-impregnated filters. The filters were then subjected to neutron bombardment. The subsequent radioactive Cl emission intensity (along with a suitable control filter) was used as a measure of the Cl concentration. Concentrations as low as 17 ppt-m were measured. Such a technique could be used for the detection of iodine and other trace species over oil fields to establish a "fingerprint" of appropriate chemical species.

J. CHOICE OF IN-SITU SOIL/AIR SAMPLE ANALYZERS

There appear to be several options open for in-situ samplers (items C-I) which allow for the possibility of extremely high sensitivity, particularly if the atmospheric samples may be brought back to the laboratory for analysis. For I_2, these devices could be either spectrophones or laser cavity Q modulators. The plasma-jet spectrum analyzer mass spectrometer and neutron activation analyzer could be used for establishing the presence of many chemical species over known oil fields.

V. SPECIFIC RESULTS/TECHNICAL EVALUATION

We shall divide our discussion into two parts: first, the available geologic/geochemical results, followed by a critique of methods and results of remote/in-situ sensing of geochemical indicators of oil/gas.

A. GEOLOGIC/GEOCHEMICAL ANALYSIS

As evident from the references cited above, if we trace the evolution of petroleum starting with the deposition of organic matter in source sediments, expulsion of pore fluids, thermal alteration of organic matter, and migration and accumulation of petroleum in traps, there exists a considerable uncertainty regarding the close physical association of iodine with petroleum reservoirs. There are several basic questions or problems to be resolved. These include (1) an assessment of whether or not iodine displays a direct association with petroleum (or with petroleum-associated formation waters), (2) the likelihood and the mechanisms of reservoir-to-surface transfer of petroleum-associated iodine, and (3) the probability and nature of release of iodine to the atmosphere. They are the sort of problems which will help evaluate the geochemical feasibility of the proposed exploration technique. Now we discuss some specific results.

To verify the release of iodine from iodine-rich surface material to the atmosphere, as well as the optical spectrometer sensitivity to detect such atmospheric concentrations, airborne tests were conducted off the Maine coast (Matinicus Island) (Ref. R-29). The results were interpreted as positive indications of I_2 of the amount 9.5-30 ppm-m. However, the measurements were not absolute because of the changing spectral distribution of the incident light during the integration time required for the measurement. No verification of this test by air sampling and subsequent mass spectrometric measurement was carried out. Samples of the kelp from the Maine coast airborne test area were chemically tested for I_2, and levels of ~0.14% (w/w) of I_2 were found. However, this is an indirect test of atmospheric I_2 levels since it is not clear how I_2 is bound up in the kelp (rock weed) and how it is liberated into the air. It is worthwhile to note that the optical spectrometer measures spatially integrated optical depth of iodine along the sensor line-of-sight. Point sampling ground-truth schemes measure temporally integrated air volume samples, and the iodine collected is generally of an unknown chemical fractionation. Passive electro-optical remote sensors should be cross-checked against sensors of a similar type.

More positive tests were carried out on a "plume chase" for NO_2 at the Lakeview Generating Station (Ref. R-29). There, the atmospheric NO_2 was detected by both the wet chemistry and the correlation spectrometer. Such a confirmation would be most desirable for I_2.

In regard to the Midway-Sunset oil field results, we quote directly from Reference R-31. "Referring to Figure R-1*, the presence of a very strong I_2 anomaly is evident at the Tar Pit near McKittrick. This is a massive oil seep associated with outcropping of the Belgian Anticline oil field. A secondary anomaly is evident at P6 with a steady fall off to a minimum value at P25. Reference to a well-location map of Midway-Sunset shows a majority of wells are located in the north and south ends of the field; while, the central region has a relatively low-well density indicating that the strong soil anomalies are associated with areas of concentrated oil production. Figure R-1* shows interesting results from a traverse which began to the west of the field at R1 and ran across the oil-bearing sand out-crop into the oil field, followed the approximate boundary of the field to R27, back into the center of the field at R28 and proceeded eastward beyond the field to R41. The highest value of 5.6 ppm obtained at R9 is believed to be associated with the oil sand outcrop which runs lengthwise from NW to SE along the foothills of the Temblor Range which bound the field on the west side. The high values of 4.9 and 4.5 ppm at R17 and R19 are probably associated with the high-well density in this part of the field." Figure R-2 shows the ground-based spectroscopic measurements. The radial lines show the directions in which the measurements were made. The length of those radial lines give the spectroscopic results in terms of atmospheric concentration-path lengths.

The catalytic method of iodine analysis for soils was attempted for measurement of atmosphere I_2 by substituting for the 100 mg soil sample, a 1.0 ml sample of a 25 ml solution from an air sampling apparatus. This was unsuccessful however because of limitations of detection limit of the method and the air sampling apparatus. The amount of air required to reach the required sensitivity was far in excess of the air flow and collection capacity of the equipment. The specific-ion electrode method was also tried; it was also unsuccessful because of the limitations of the air flow apparatus and possibly H_2S interference. The wet chemical results reported in Ref. R-31

*Renumbered for this report.

Figure R-1. Topography of Midway-Sunset Area Showing Sensor Sites and Soil Sample Traverses P,Q,R,F. Taft, California. April, 1970. From Ref. R-31

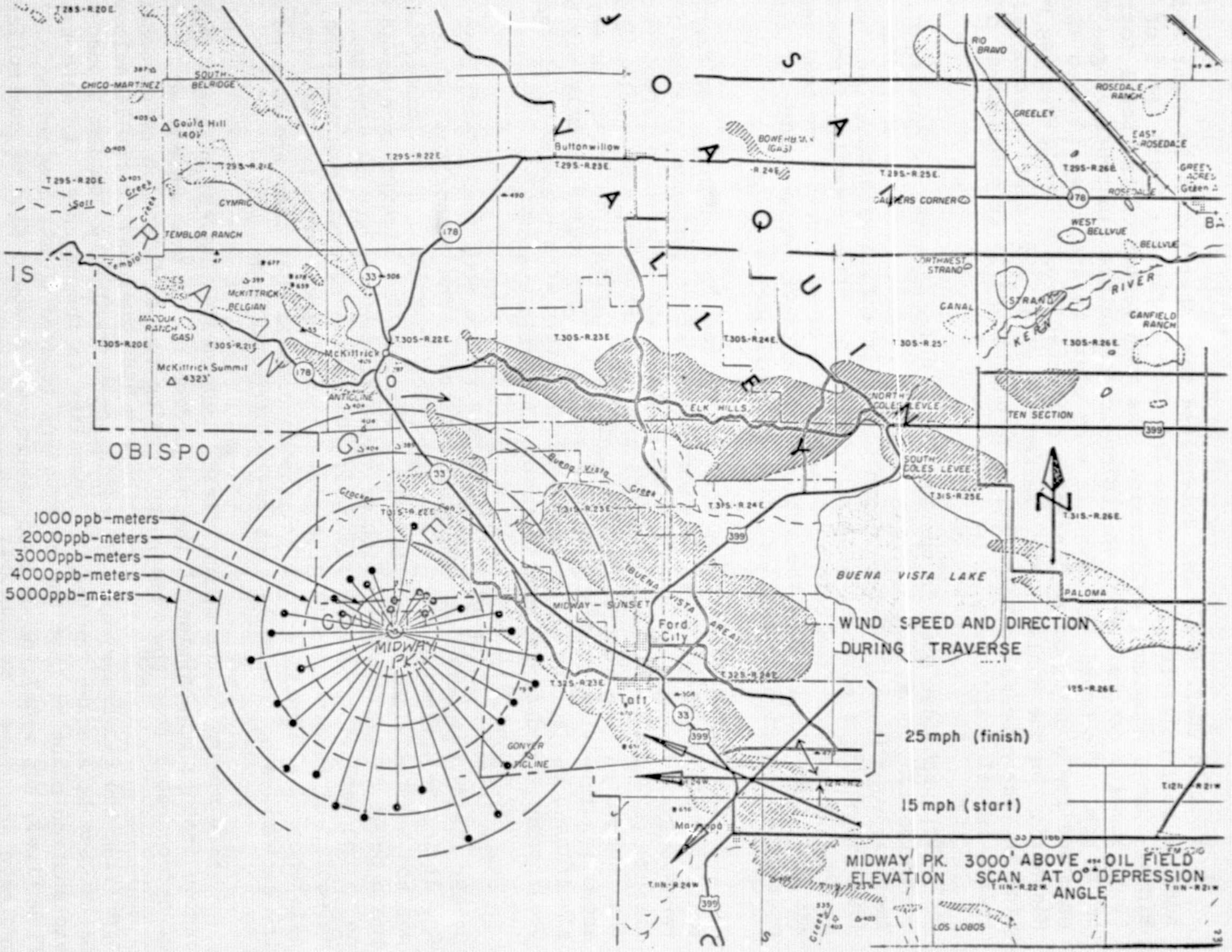

Figure R-2. Plot of Optical Spectroscope Sensor Responses From Midway Peak. May 8, 1970. From Ref. R-31 therefore do not include atmospheric iodine but are restricted to representative suites collected of rock and soil samples.

Ficklin (Ref. R-27) has determined the total iodine in eight samples of surface soil collected by R. Lantz from the Cymric oil field (part of the Midway-Sunset complex), California. The mean values of the total iodine in these samples determined by an iodine-ion-selective electrode ranged from 0.9 to 12 ppm. The preceding range is very close to the range (1.1 to 12.3 ppm) observed for a suite of soil samples collected from a nonoil-bearing region in Missouri. On the basis of the limited number of soil samples reported on by Ficklin, there seems to be no evidence that there is an enhancement of surface iodine in oil field soils.

The technique used in the Gobel field, Ontario (A. R. Barringer, private communication, 1976) was Airtrace, and the findings include an iodine anomaly. The reservoir is at 3000-feet depth (lower Paleozoic sandstone) and has a 150-foot surfical cover of glacial drift. The latter deposits frequently accumulate methane from bacterial alteration of entrapped (ice age) vegetal matter. This complicates the interpretation of the relationship of a surface anomaly of any kind to the deep Paleozoic oil accumulation.

In the simulated Airtrace work in the San Juan Basin (A. R. Barringer, private communication, 1976), concentration variations were obtained in relative terms only. "Anomalies" over the Medio field and adjacent prospective areas include (P + I + Sr), (Cr + Fe + Al) and (I). However, the results should have been subjected to a multivariate discriminant analysis to establish any significant anomalies involving several chemical species. The iodine anomaly may be significant due to its unique geochemical origin with respect to oil/gas occurrences and deserves consideration as possibly authentic.

The interpretation of Barringer's Airtrace work (Ref. R-42) over the Cement field, Oklahoma, is very problematical. The "anomalies" of Al, Ca, Cr, Bi and Sr (relative of Si) are described in a qualitative manner and may not be statistically significant. The test for significance based on the product of the concentration of these elements is not convincing. Again, as in the case of the Medio field, if 20 or more elements are analyzed, a selection of elements could give rise to an apparent anomaly. Granting the existence of elemental anomalies, the conclusion that they are related to the subsurface oil accumulations may be unjustified.

With regard to the Cement field, Donovan (Ref. R-43) contends that the carbon isotope composition of the subsurface fluids was controlled by leakage of hydrocarbons from the reservoirs leading to the formation of carbonate cements enriched in C^{12} (as are petroleum hydrocarbons) in the lithology overlying the oil reservoir. He relies on several more complex processes and mechanisms to account for the O^{18} anomalies in the cements. An alternative explanation might be that the cements are related to shallow meteoric fluid flow (i.e., not expulsion of deep waters) which would also be controlled by the geologic structure. Bicarbonate in surface waters is also C^{12}-rich and could possibly account for isotopically light carbonate cements. The high O^{18}-value displayed by the cements could be accounted for by the low-temperature precipitation and inherent O^{18}-enrichment of solids relative to H_2O due to low-temperature isotopic fractionation. In this case, the "anomalies" are controlled by the <u>geologic structure</u> not by the oil accumulation. The anomalies share a genetic structural control with the oil occurrence but are themselves not genetically related. It is not possible to reject out-of-hand Donovan's interpretation and Barringer's use of it. The Cement field should receive further consideration as a possible field test area.

B. REMOTE-SENSING INSTRUMENTATION AND RESULTS

The problem of remote sensing of atmospheric iodine falls into two parts:

1) The assumption of sharp absorption lines of iodine when it is in the presence of 760 torr of quenching gases (N_2 and O_2)

2) The experimental difficulties associated with the spectrometer itself.

The vibrational levels in the upper B state (the electronic state responsible for the visible absorption) could be washed out by the strong collisional quenching of I_2 by N_2 and O_2 to give iodine atoms (Ref. R-44). Moreover, since there are about 30 rotational lines/0.1 nm for I_2 at 530 nm, a mask 0.6 nm wide (Ref. R-29) would average the I_2 spectrum over ~ 180 lines. Since the purpose of the mask is to create a "fingerprint" of the desired molecular spectrum, both effects just described (collisional quenching and instrumental resolution) would tend to work against discrimination of I_2. It is interesting to point out that the collisional quenching gives rise to the possibility that I_2 could be destroyed by sunlight by the steps: I_2 + sunlight → excited I_2 (B state) → I atoms (collisional quenching). This path of I_2 removal makes it probable that the already small steady-state concentration of I_2 produced by an oil field would be reduced even further by collision-induced (and natural) predissociations (Ref. R-45).

In order to study the collisional quenching effect (possible washing out of the vibrational structure), experimenters at JPL have obtained I_2 absorption spectra in the presence of 732-torr air (Figures R-3 and R-4). The spectra show banded structure superimposed on a continuum in the interval λλ 620-505 nm. The separation of the bands is ~ 1.8 nm at ~530 nm. Barringer (Ref. R-28) uses a mask optimized for the region 578-531 nm which covers this banded region. It thus appears possible to design a mask that would be able to correlate with the absorption spectrum of trace quantities of I_2 in air. That is, the spectrum of I_2 in air is sharp-lined over the mask wavelength interval, and not a continuum due to air-I_2 collisional broadening. It should be noted that water vapor exhibits some weak absorptions in the 530-nm to 580-nm region used for the I_2 correlation spectrometer. This interference can create a problem as water is variable in the atmosphere and cannot be once and for all compensated for.

With regard to the instrumental problems, we start with passive correlation spectrometers. These may be mounted on aircraft for aerial surveys and would be operated in a sideways looking mode so as to achieve the longest possible light path through the iodine distribution and hence the highest possible spectral absorption. The sensitivity of the correlation spectrometer is a complicated function of the instrumental parameters, the intensity distribution of the incident light, the variation with wavelength of the absorption cross-section of the gas of interest, interfering absorptions, and achievable path lengths.

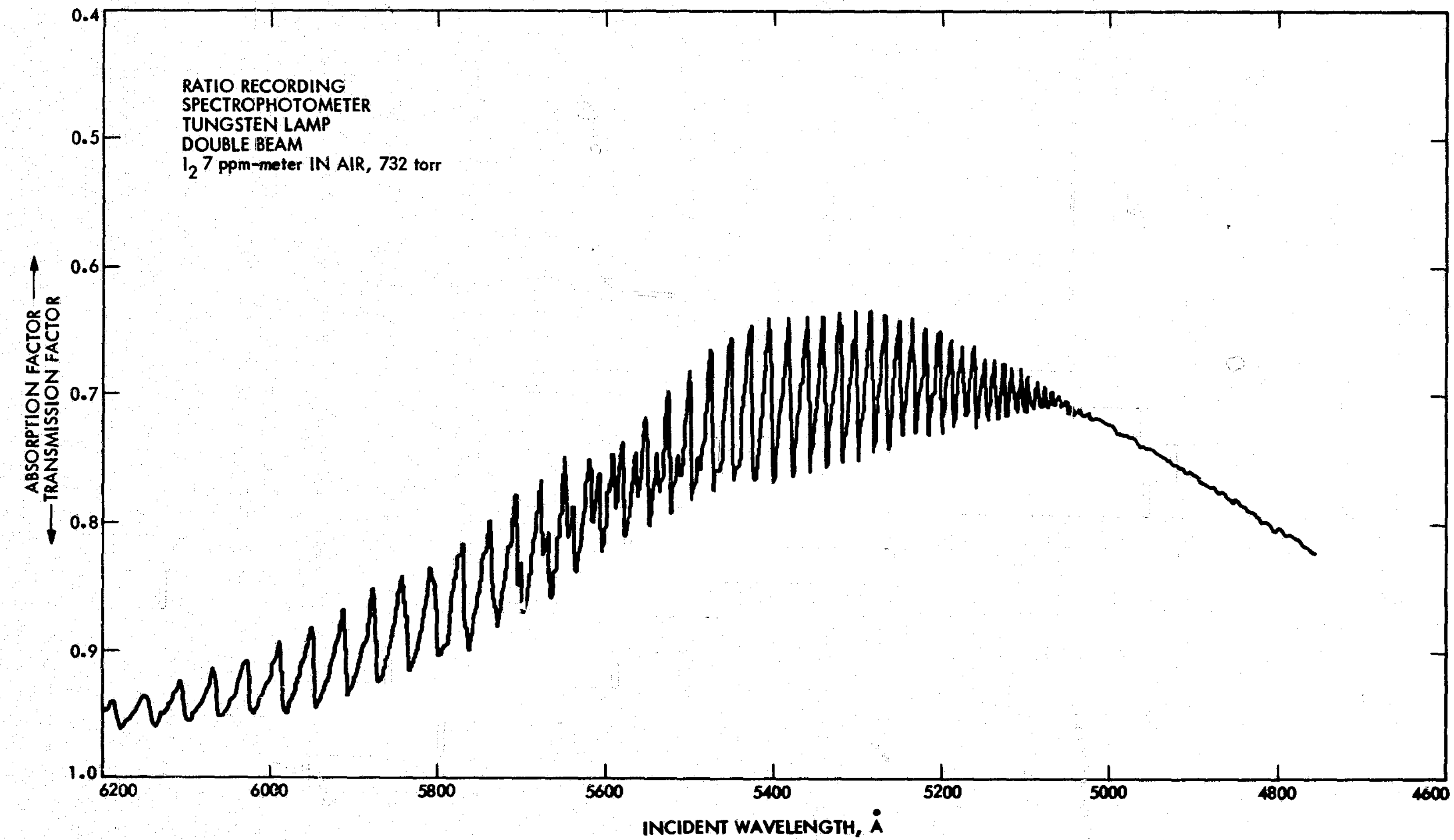

Figure R-3. I_2 Spectrum at Atmospheric Pressure

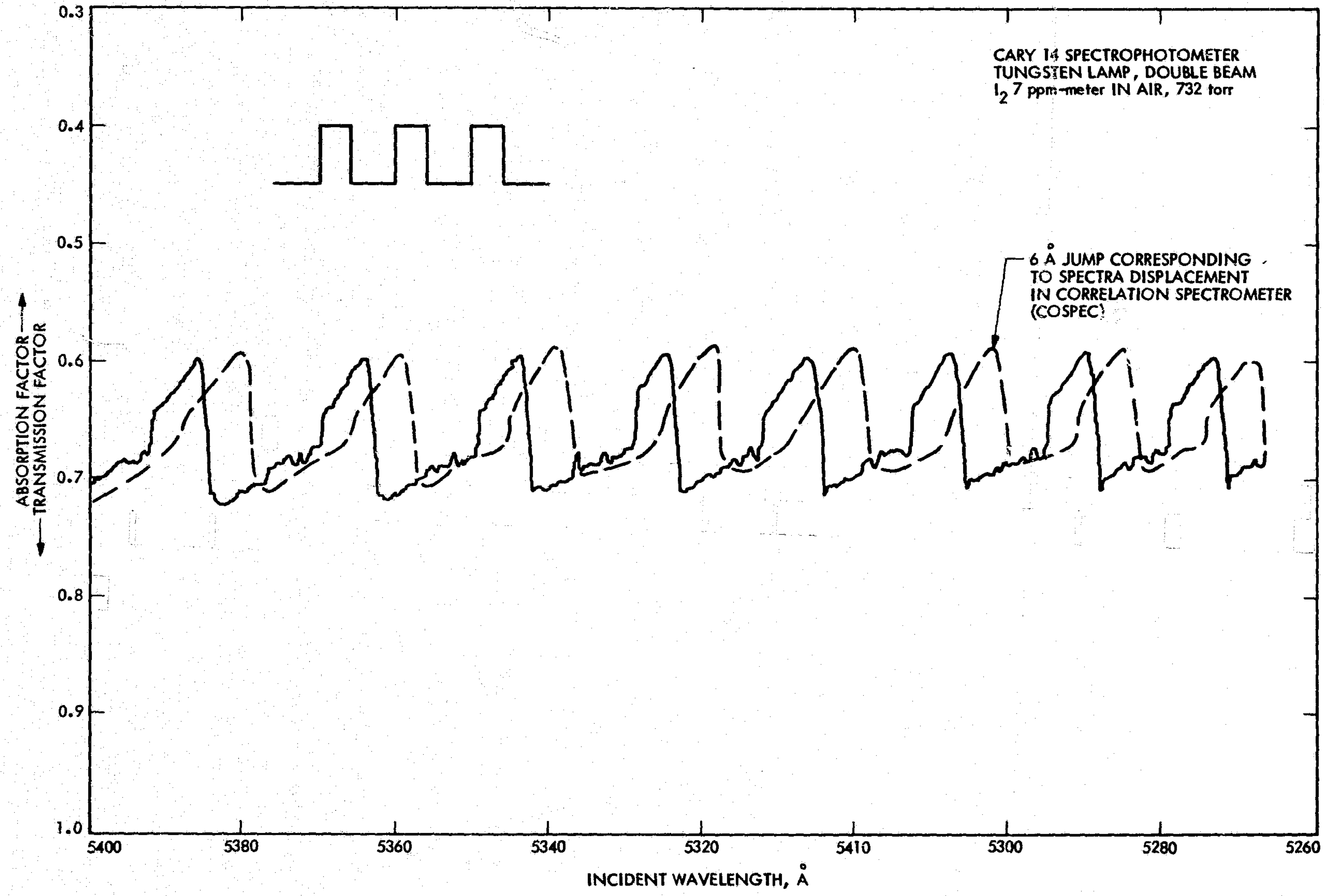

Figure R-4. I_2 Spectrum at Atmospheric Pressure (greatly enlarged)

Absorptions which are below the level of the atmospheric noise, which tends to be high (10 ppm-meter), cannot be measured. The atmospheric noise can be reduced by using long integration times, but this procedure prevents the use of aircraft particularly if the I_2 concentrations are originating from highly localized sources.

Furthermore, the response of the instrument to the gas of interest may be double valued; that is, the COSPEC instrument may give the same response to two different concentration of the same gas. However for I_2, this is not serious as the double-value is at unusually high concentration. In general, the stronger the absorption features of a particular gas, the more sensitive the instrument is as a detector of the gas.

Using identical light sources and identical light filters, Millan et al. (Ref. R-28) have obtained the correlation output with and without 250 ppm-m of SO_2 (a large amount of SO_2). If one superimposes these two spectra (Figure R-5 on top of Figure R-6), it is obvious that the output is largely dominated by the no-gas response of the instrument (given by Figure R-5). Two important factors of this no-gas response are the λ-variation of the incident spectral intensity and of the instrumental transmission and are discussed in detail in Reference 28. The variations due to SO_2 are in the righthand portion of this spectrum (Figure R-6). They appear to be a relatively minor part of the total spectrometer output considering the large concentrations of SO_2 involved. Note that the peak concentration (anomaly) obtained over the Midway-Sunset oil-field by observation from the Midway Peak was only 5 ppm-meter I_2 concentration. This is a factor of 50 lower concentration than the SO_2 measurement.

Barringer (private communications, 1976) claims the sensitivity of COSPEC is 10 ppm-meter operated in the field where its sensitivity is limited by atmospheric noise. This indicates an ultimate sensitivity of approximately 10 ppb of uniformly distributed I_2 vapor in a 1-km path. Without going through the extensive and detailed calculations involved in computing the response of the correlation spectrometer to the I_2 spectrum, it is not feasible to give an accurate estimate of the sensitivity of the device. We can, however, make some qualitative remarks.

1) If the device is to be used from an aircraft, it must operate with a short time constant, τ, so that it will not be confused by the varying albedo of the ground below, and the field-of-view will not have moved too far during a comparison cycle. The signal/ noise will vary as $\sqrt{\tau}$. Note that while the comparison between the correlating and anticorrelating position is done simultaneously in GASPEC, it is done sequentially at about 30-Hz rate in the COSPEC.

2) GASPEC device (Ref. R-32) has used emitted incident radiation from the trace vapor as well as absorbed incident radiation. A similar device described by Goody (Ref. R-46) uses absorbed radiation by the trace vapor. The GASPEC type of device used in detecting infrared emissions would not be useful for I_2. It has to be modified to detect visible-wavelength absorptions and emissions in I_2.

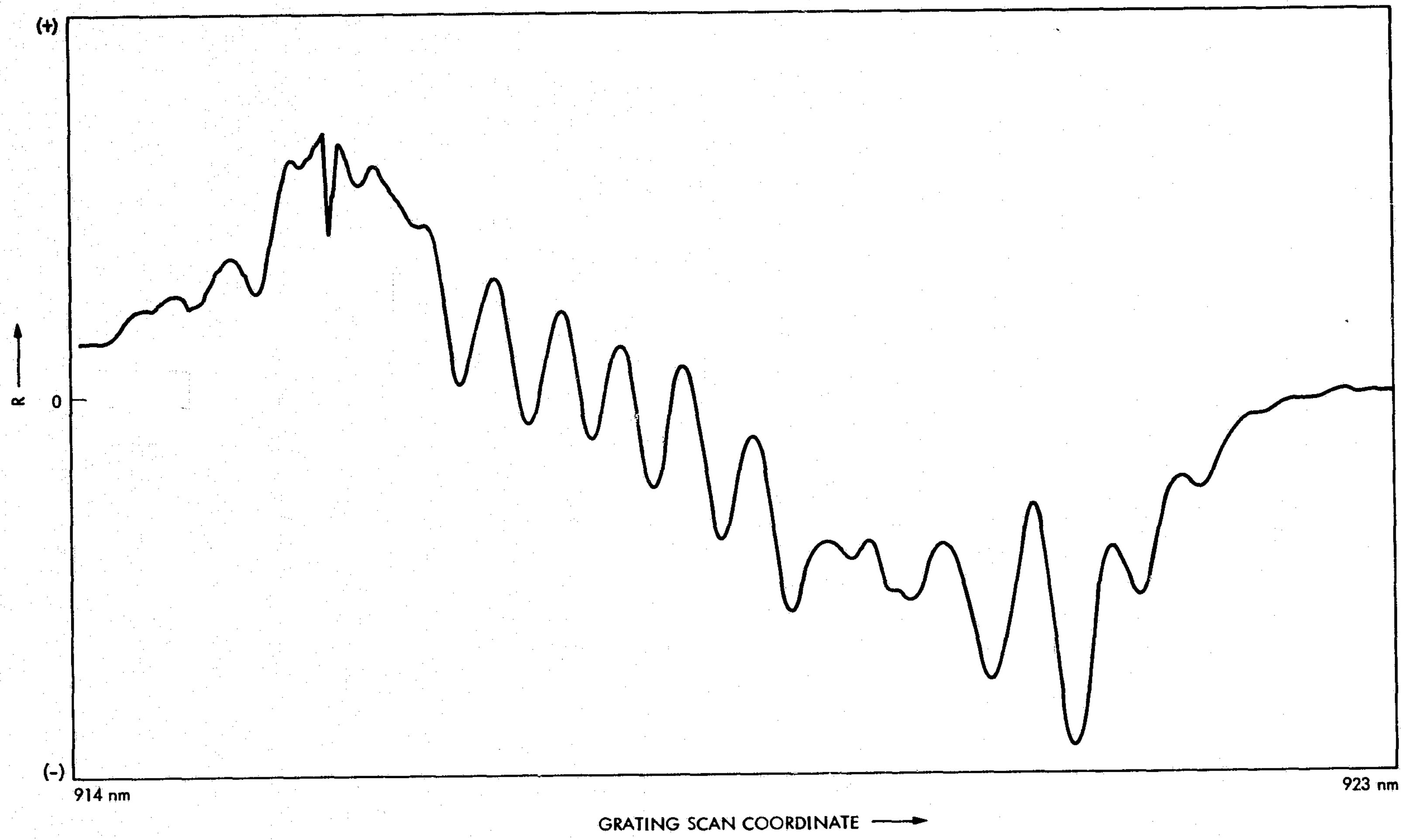

Figure R-5. Scanning Response of COSPEC Instrument Using Skylight and an SO_2 Mask over Spectrum with Zero SO_2 Concentration-Path Length. (From Ref. R-28.)

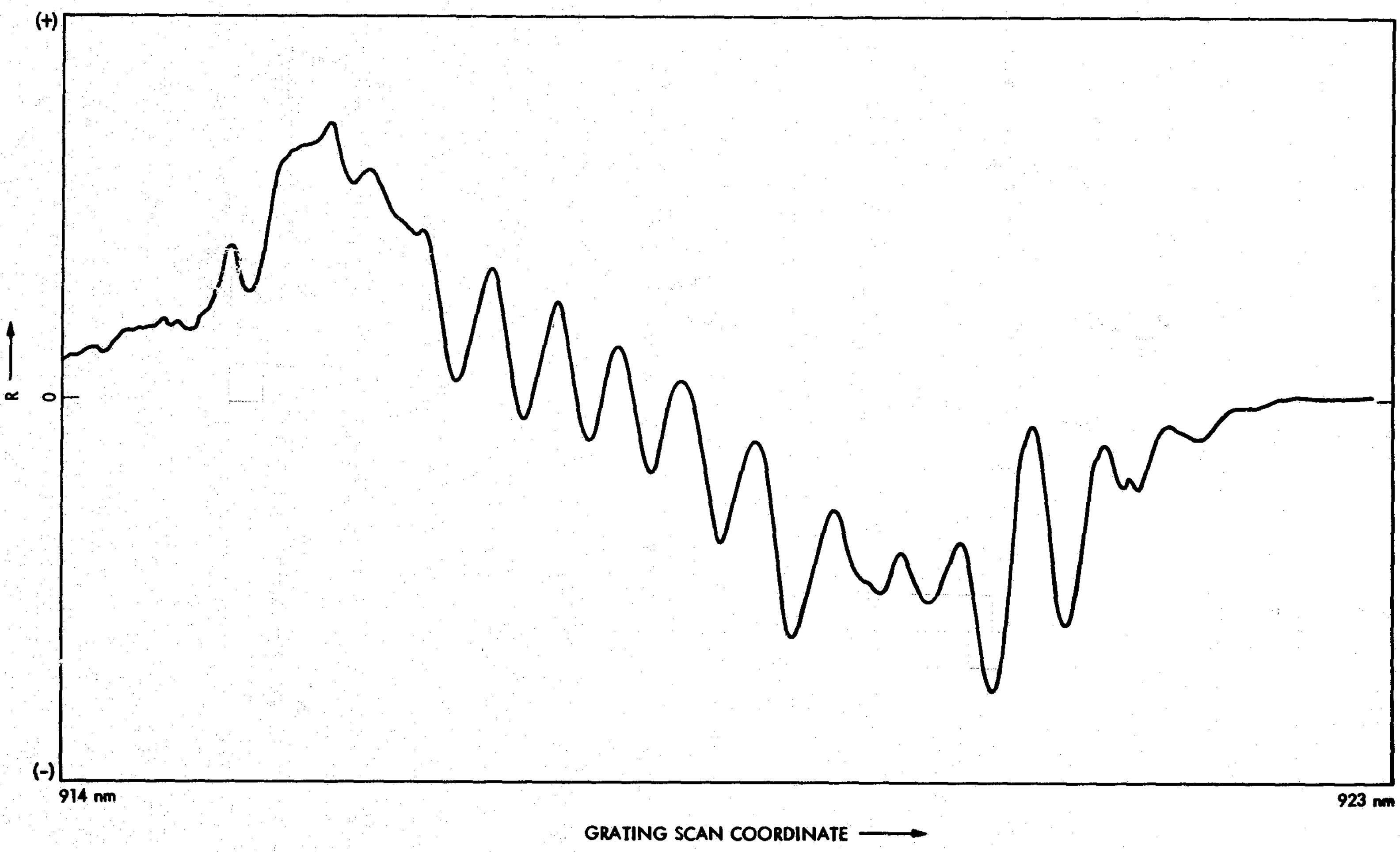

Figure R-6. Scanning Response of COSPEC Instrument Using Skylight and an SO_2 Mask over Spectrum with 250 ppm-meter Concentration-Path Length. (From Ref. R-28.)

The 5 ppm-m anomaly noted by the ground-based Barringer team (Ref. R-31) over the Midway-Sunset-oil fields was done with a $\tau \sim 1$ sec. If τ is as short as 10^{-3} sec (which would seem to be required for aircraft flights), the sensitivity would be reduced by approximately 30. It would seem that the best mode of operation would be with an artificial light source (active mode) with no spectroscopic structure (emission lines) of its own, rather than with the reflected solar light (passive mode) which has a great deal of interfering structure.

It seems reasonable to conclude that there are at present no reliably good remote sensors of I_2. There are some good enough in-situ sensors, and it seems reasonable to suppose that remote sensors could be developed if there was sufficient reason to do so.

VI. DEVELOPMENT

The odds for the successful development of an iodine direct surface-petroleum prospecting method are low. However, as for other direct prospecting methods, a successful development could have a major impact on petroleum exploration and the discovery of additional energy reserves. Hence, despite the low probability of success, a carefully monitored low-level effort is considered justifiable. Also, the results will have implications to problems of air pollution, the geochemical cycle of iodine and its importance to human health, and an improved understanding of the chemical significance of surface and subsurface waters, and may reveal heretofore unrecognized surface prospecting techniques and methods which could then be developed.

If development is undertaken, the recommended program is as follows.

The program should be initially addressed to in-situ measurements of iodine over areas expected to be drilled. These measurements should be made with the most sensitive instrument available and should determine total iodine content. It is important here to make the measurements with sufficient speed and spatial resolution to determine the chemical form, concentration levels and the spatial extent (including the vertical, if possible) of the atmospheric iodine. Tests would include separate chemical analyses of particulate and gaseous portions of air and corresponding analyses for iodine in the soil and near-surface water.

1) The first phase would consist of tests made over and on

   a) Known producing oil fields and gas fields.
   b) Areas geologically unlikely to contain petroleum.
   c) Areas with young marine deposits.
   d) Prospects already drilled where no petroleum was found.
   e) Prospects not yet drilled but where drilling is planned. Correlation of predrilling iodine observations with the results of drilling would be attempted.

Effects will be determined of site variables such as distance to the sea, direction of the sea relative to prevailing winds, climate, and soil composition, and of sampling variables such as time of day and year, ambient temperature and pressure, wind velocity, cloud cover and incident solar radiation, rain and snow.

Moreover, it is recommended that, in these in-situ measurements, attention be given also to other trace species which are present in the atmosphere. In this way, one may establish a multiparameter correlation "fingerprint" of atomic and molecular species with known oil fields. The flame spectroscopic, mass spectroscopic and neutron activation techniques are sensitive and suited for this type of measurement. The former would detect emission lines from many trace species; the second would record their masses, and the last characteristic nuclear decays of the trace species.

2) In a second phase, once these in-situ techniques have established I_2 and other concentrations, attention should be turned to the commercially available remote-sensing devices. It can then be determined from the measured concentration and distribution of the "fingerprint" species what sensitivity is required and which devices should be used for remote sensing.

3) The third phase should be devoted to the construction of improved remote-sensing breadboard instrumentation suitable for field tests.

4) In the fourth phase, field tests would be conducted from ground and aircraft with the breadboard over areas such as those listed in item (1).

5) If the technique then appears promising, a follow-up effort would include design, construction, and test of a spacecraft prototype version of the instrument.

In the first year of effort, items (1) and (2) would be covered. The Milestone Schedule would be as follows:

1 year after work start:	Complete field tests for iodine.
2 years after work start:	Complete construction of improved remote sensor breadboard.
2-1/2 years after work start:	Complete field tests of remote sensor breadboard.

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APPENDIX S
TECHNICAL DETAILS ON TOPOGRAPHIC MAPPING AND IMAGING OF LARGE AREAS OF THE SEA FLOOR

I. IMPORTANCE OF TOPOGRAPHIC MAPS AND IMAGE MOSAICS TO PETROLEUM EXPLORATION

In unexplored areas, remote-sensing (sonar) surveys can be used to indicate structural trends or anomalies so that subsequent seismic surveys may be planned to investigate areas having a greater likelihood of petroleum deposits. Similarly, these surveys may be used in explored areas to reexamine and ensure that potential oil deposits have not been misinterpreted or overlooked.

Remote sensing surveys can be utilized in petroleum exploration as a regional reconnaissance method used in advance of more expensive detailed local or site surveys. The results of these surveys--data digitally collected and processed to produce more detailed bathymetric charts, shaded relief maps, or sea-floor image mosaics--can, as discussed in Vol. 1, Section 3-F-7, be used for two main purposes: (1) geologic interpretation of the sea bottom topography and (2) production planning.

II. PRIMARY OBJECTIVES OF THE STUDY

With a view towards utilizing aerospace-derived technology where applicable, the study had the following objectives:

1) Investigate present state-of-the-art of bathymetric and topographic imaging (side scan) surveying techniques.

2) Investigate present state-of-the-art of echosounders and side-scan sonars for use as bathymetric and imaging survey instruments.

3) Conceive and evaluate total system concepts that include data acquisition, digital data processing, and image processing and enhancement that will satisfy user requirements and needs.

4) Make recommendations regarding feasibility of system concepts and future study work.

III. STUDY APPROACH

At the outset, study efforts involved a literature search (periodicals, technical papers and reports, and texts) that dealt with the sonars used in hydrographic surveying and the techniques used in the performance of these surveys. The search also included the use of side-scan sonars for sea-bottom imaging. Several technical papers from the 1976 Offshore Technology Conference and textbooks were located that proved useful in acquainting study team members with present sonar technology and sea-surveying techniques. As a parallel effort to the literature search, interviews and phone contacts with experts from the oil industry, U.S. Government, academic institutions, and JPL were conducted for opinions, advice, and knowledge about the need for better topographic maps and imagery to aid in the search for undiscovered oil deposits under the sea floor. The next phase of the study involved system synthesis and system analysis (1st order approximations) of concepts that would be capable of producing better topographic maps and image mosaics of large areas in an economical manner to enhance the oil exploration process. Functional system concepts evolved after the analysis was completed and are discussed in this study report.

IV. STUDY RESULTS AND FINDINGS

A. TOPOGRAPHIC REQUIREMENTS FOR PETROLEUM EXPLORATION

Exploration geologists desire images of large areas of the sea floor for geologic identification and evaluation. They want images of the ocean floor comparable to aerial photographs of the land area. These images should be of such scale and extent that large geological features on the order of 5-mile dimensions can be depicted while also showing surficial details sufficient to interpret the underlying structure. Imagery will be used by these geologists to locate, identify and assess surficial expressions underlying structure and other geological factors critical in the location of subsurface oil. Pictures or images are desired as opposed to topographic, bathymetric, or geologic charts and maps--primarily because maps represent some other person's interpretation of the field observations and data in his formulation of the map. The interpretation of the image data is part of the geologist's art where experience, prior successes, position, and background determine the conclusions. Assessment of sea-bottom topography is also necessary and critical for engineering considerations of offshore drilling, extraction and pipe laying facilities.

Historical experience and prior work have indicated that acoustical techniques as opposed to optical and electromagnetic means are the only practical ones for making images of reasonably large areas of the sea bottom. Film and television images can be obtained of small areas for detailed study of the sea bottom. The wide-angle cameras on the MPL deep tow of the Scripps Institution for Oceanography, can, for example, photograph an area of 15 by 15 meters to a film and lens resolution of about 30-lines/mm, or 2 cm on the bottom. Many millions of such pictures would be necessary to cover the area of a Landsat image.

It is desired that sea-floor geomorphology be displayed as mosaic images for large areas to a resolution that will facilitate the recognition of features such as faults, rock outcrops and possibly their alignment, and folds (anticlines, domes, synclines) in a manner that these images would provide valuable information for locating possible petroleum deposits much in the same way as it is done with land imagery. Further, these acoustical image mosiacs should be capable of being made into areal maps displaying regional geology to a resolution comparable to Landsat photo mosaics.

The production of bathymetric and geologic charts can follow from the data obtained through sea-floor imagery as will be outlined later. These charts will then be useful in depicting hazards to navigation and bottom contours for seismic operations, drilling, and other exploratory and operational petroleum industry functions. All information gathered and displayed should be available in digital format.

B. BATHYMETRIC CHART REQUIREMENTS FOR PETROLEUM EXPLORATION

Petroleum exploration managers and geologists desire better bathymetry on the charts that are available to them today. Present day maps are not detailed enough for the covered area in regards to depth soundings and spacing of line contours. For purposes of identifying basins, scarps, shoals, pinnacles, reefs, etc., geologists require more accurate bathymetry and closer line spacings for evaluation of the sea-floor topography. More accurate and detailed maps aid geologists to determine where slump areas and rock outcrops may exist. The scale of these maps should be as large as the data density permits --to 1:5000. Engineers and exploration managers require greater positional accuracy of underwater hazards for purposes of planning operations at sea. Setting up survey plans and potential work areas requires good location of sea-bottom features that may prove detrimental and hazardous to on-going work. Also, it is desirable to be able to return and locate a "plugged" well with greater precision. All information gathered and displayed should be available in digital form.

C. BACKGROUND AND CONSIDERATIONS FOR SYSTEM SYNTHESIS AND ANALYSIS

1. Bathymetry - Its Purpose and Use

Soundings are taken at intervals and spacings dependent on water depth, bottom relief character, survey scale, and particular importance of the area in question. The primary goal of most local and regional depth measurements has been the safety of navigation. Indications of submerged dangers such as wrecks, pinnacles, banks, shoals, mounts, etc., in the bottom relief are developed through representative spacings which may be varied as needed.

The practical limit of spacing lines in sounding is presently determined by the desired plot or chart. Current hydrographic chart standards (Ref.S-1)* allow for 5 to 6 mm between contour lines, at the least, normally decreasing to 3 to 4 mm in difficult areas. These "standards" are quite often altered in shoals. Rocky and abrupt inclinations must be surveyed more closely and sandy smooth bottoms less so as rapid depth changes are not expected. Shallows and deeps must be more closely investigated as they may indicate scours or deposits from currents. Wrecks, of course, are indiscriminate as to the character of the bottom.

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*References are listed in the end of this appendix.

2. Speed of Sounding

Navigational safety, survey scale, depth, echosounder rate, and sea state all determine the sounding vessel's speed of advance and depth recording interval. Navigational safety and sea state constraints are judgemental, but the limiting parameters for the other factors are analytic.

For depths less than 300 meters, an echosounder pulse requires 0.2 second or less to reach the bottom and 0.2 second or less to return at the normal speed of sound of 1500 m/s. Utilizing the extreme of 3-mm spacing between lines at a chart scale of 1:10,000 allows for a speed of advance of 30 meters in the 0.4 seconds between pulses or 150 kts!

A half-power beam width minimum of 100 milliradians (about 5 degrees) at the echosounder transducer is needed so that the advance between transmit and receive is still in the beam pattern. For narrower beamwidths, correspondingly slower speeds are indicated. The amount of desired overlap of insonified areas of the bottom will also limit speed. In any event, the speed of advance in shallow bottom sounding is seldom limited by sounding physics or equipment but by the speed of the survey vessel.

3. Physical Characteristics of Side-Scan Sonars

Side-looking sonars which insonify a vertical fan at right angles to the track have been used for acoustic imaging of the sea floor. The obtainable coverage using side-scan acoustic techniques is limited by several physical factors. These are the speed of sound, attenuation versus frequency, noise, reflection angle, temperature distributions, and reverberations.

The combined effect of these factors is to limit the ranges and resolutions obtainable with acoustic methods. The resolution in range is determined by the sonar frequency and pulse width. Higher frequencies allow for shorter pulses and greater resolution but limit the maximum range owing to increased attenuation. The along-track resolution is determined by the beam width in azimuth which is a function of the real aperture or transducer length in wavelengths. Azimuth beam width and range together with the propagation-of-sound limitation determine how much area of the bottom can be covered with each pulse. This, in turn, places some restrictions on the speed of advance.

Side-scan sonars are usually towed or positioned at a height above the sea floor of 1/10 to 1/7 of the maximum range. Lower heights result in such shallow grazing angles at long ranges that inadequate reflections are realized. Towing higher severely restricts the range resolution at close ranges due to the oblique angle of the bottom at short sonic ranges. The 300-meter shelf depth would limit maximum ranges at 2100 to 3000 meters.

4. Performance Capabilities of Commercial Echosounders and Side-Scan Sonars

Almost all commercially available echosounders and side-scan sonars, are delivered as complete self-sufficient instruments save for a primary power source. Transducers, transmitting and receiving amplifiers, and permanent graphic recording devices are furnished. Many of the operational functions and controls are required to compress the 80- to 100-dB dynamic range of the sonar signals to the 12- to 26-dB dynamic range of the recording device. In addition, the recorder mechanical drive and recording material often limit or cannot reproduce the received electrical signal and therefore degrade the range resolution. The recorder is also quite often the basic timing or keying unit, and the sonar operation is not as flexible as it could be. The electrical performance and flexibility that can be obtained from commercially available sonars is probably superior to the published data since the realizable performance is severely compromised to accommodate the poor response of the recorder.

Currently, there are a host of available echosounders adequate to the task of determining depth in waters up to and beyond 1000 meters deep. The accuracy of measurement is on the order of 1 part in a 1000. The insonified cone or pyramid is usually about 200 mrad between the half-power points, covering an area with linear dimension on the sea floor equal to 20% of the depth.

Similarly, side-scan sonars are commercially available with ranges to 300 meters for units operating at 100 kHz and greater and 600 meters for lower frequency types. The beam widths are usually 2° or less with one unit specifying 0.3° in azimuth. All side scans operate in the "searchlight" mode with the same transducer used for transmit and receive. This technique allows for longer range, as the noise level for receiving is reduced in the same manner as transmit power is increased by the beam directivity.

5. Special Purpose Side-Scan Sonars and Performance Characteristics

Research and development side-scan sonars are operated by various governments, and these units have much greater ranges--up to 22 km for one deep-water unit. These sonars are one-of-a-kind, and though they are not generally available, their performance is indicative of what can be done.

All real aperture side-scan sonars exhibit good range resolution which is roughly one-thousandth of the maximum range. The azimuth or along-track resolution becomes poorer with range because of the geometric spreading of the acoustic beam. Typical beam widths of 10 to 20 mrad will yield along-track element sizes of 1 to 2% of the range to the object. At maximum range, the along-track resolution is 10 to 20 times worse than the range resolution. The resolutions are equal at about 1/10th of the maximum range, but this corresponds to the towing height, so the along-track resolution is only comparable to the range resolution at or near the nadir point beneath the side scan.

When high along-track resolution is required, the narrow beam of the side scan necessitates a relatively slow speed of advance when compared with bathymetric or even seismic surveys. The speed of advance is limited by the beam width at minimum range divided by the time required for the pulse to travel to maximum range and back. For a 20 mrad beam (1° +), the speed would be 3.7 kts for a 300 meter maximum range yielding 0.6- to 6-m along-track element size. The speed of advance is inversely proportional to maximum range and directly to beam width. Higher speeds are possible with a consequent loss in along-track resolution as a result of the needed wider beam.

An alternative approach for greater area coverage is to accept the poorer resolution and not provide complete overlapping coverage of successive beams. Under these conditions, the speed could be increased in the foregoing to about 30 kts. The probability of detecting any object smaller than 6 m would be roughly 50% as only half the botton would be insonified.

6. Synthetic Aperture Sonar

No sonar is commercially available which takes advantage of synthetic aperture techniques in the manner of side-looking radar. The principal reason is the factor of 20,000 in the speeds of propagation of radar and sound waves. The slow speed of sound in water has limited the advantage of synthetic as opposed to real-aperture side-scan sonars. So that the increased along-track resolution of a synthetic aperture can be realized, a higher pulse rate is required than for a real aperture, and with sonar, this results in more than "one pulse in the water" which causes a range ambiguity. That is, the returns are difficult to relate to the pulse that caused them. Moreover, area coverage tends to be less with synthetic than with real apertures.

A technique is being studied now that uses one transmitter and several receivers. The receivers look at different angles, fore and aft, and on the beam so the echoes from targets are "handed-off" from one receiver system to the next as the sonar goes by the target. This may allow for higher tow speeds and increased along-track resolution which is constant with synthetic aperture.

Processing of synthetic aperture sonar is aided by the slow speed of sound and the low bandwidth and frequencies. It also appears that charge coupled devices (CCDs) can accommodate the required dynamic range, storage, and transverse filtering. The image output of the processed returns consist of geo-coded (see Section V-A-1-b below) picture elements suitable for direct computer entry and subsequent processing or a direct slant radar type image.

The synthetic aperture sonar and CCD processing of radar are expected to be operational in the next 2 years.

7. Rates of Area Coverage for Surveys

A valid comparison in the performance of sounding equipments, side-scan sonars, or combined bathymetry and imaging systems is the area that may be surveyed in a given time. These figures may be related to ship time which is the most costly item in the operational use of the surveying instruments.

As developed previously, the speed of advance in nonoverlap bathymetry can be quite high. The speed is directly proportional to along-track beam width and inversely proportional to depth. The insonified area on the bottom similarly determines the resolution or the maximum slope that can be reproduced from the data record.

The echosounder example allowed 150-kt speed of advance for 30 meters of insonified along-track bottom in 300-meter deep water. If a cross rectangular sweep pattern in employed, then the area rate is a function of the line spacing and is equal to half the area divided by the line spacing times the speed. For a 75-meter spacing, the area rate is 10 km^2 per hour. For more realistic speeds, such as could be maintained by small power boats, the rate would be substantially less. A 30-kt speed of advance could cover 4 km^2 per hour. At 15 kts, the coverage is down to 1 km^2 per hour.

High-resolution side-scan sonars to both port and starboard with complete overlap would require track lines about 300 meters apart. Using the previous example of a 3.7-kt speed of advance, the coverage rate would be the area divided by the product of spacing and speed or 4 km^2 per hour. This rate can be increased by increasing the beam width with a consomitant along-track resolution loss and/or completeness of coverage. The 30-kt speed of advance yielding 6-m element size would allow for area coverage of 16 km^2 per hour. At the more realistic speed of 15 kts, the coverage is 8 km^2 per hour, but the resolution is improved to the point that there is a 75% probability of detecting 3-m targets. Increasing the required element size to 60 m (better than Landsat A and B) would permit increasing the range and area coverage by X10 even without increasing the ship speed.

8. Navigation Considerations and Capabilities

There are two important implecations in employing short-range side-scans and close-spaced high-speed bathymetry. First, achieving the same consistency between made course and percentage overlap in parallel courses requires a very high degree of navigational precision. The ratio of overlap to the standard deviation of the location system versus confidence that the entire area has been covered has been determined by others. For 99% confidence, the overlap is twice the navigational accuracy. Second, the slow speeds for high-resolution side-scan may be less than that required to maintain a course against wind and tide for many ships.

Satellite navigation can yield, when augmented by accurate velocity data and LORAN C, one-sigma accuracies of 60 to 90 meters on a single satellite pass at elevation angles between 15 and 70 degrees. Single passes when stationary can provide 30 to 15 meter accuracy. Translocation fixes, where the corrections to the orbital parameters of the same satellite pass are determined from a well-established shore base and sent to the ship, can provide accuracies of 6 to 3 meters. The last technique is used to position drilling platforms. Acoustic transponder arrays together with satellites, and radio aids can provide positional fixes and locations of 2-5 meters.

The second problem of slow-speed maneuvering is usually solved by use of specialized ships for survey purposes.

V. PROPOSED SYSTEM CONCEPT

A. SYSTEM DESCRIPTION AND FUNCTIONAL BLOCK DIAGRAM

An integrated system concept to produce images of the sea-floor and/or bathymetric charts to user requirements will be described.

It should be clearly understood from the outset that if a combined system is desired (bathymetry and imagery data collection), then the rate of area coverage will generally be reduced. However, the system may be designed to operate in the singular data collection mode (bathymetry or imagery) or in a dual data collection mode (simultaneous bathymetry and imagery). Shallow-penetration seismic measurements would probably also be made simultaneously to obtain more information about the bottom and sub-bottom. A system that includes deep-penetration seismic measurements could doubtless also be designed.

A simplified functional block diagram of the proposed system is shown in Figure S-1.

1. Bathymetry Subsystem

a. <u>Data Collection</u>

Bathymetric data collection may be done by ship or boat, towed instrumented "fish," or even helicopter-towed package. The ship or boat requires an echo-sounder with automatic bottom tracking and provisions for recording the numerical output. The others, including the helicopter towed package, required not only an echosounder but either a depth measuring pressure gauge or an up-looking sonar. The up and down measurements are then added to obtain the sounding. Further study will be required before an implementation mode can be selected based on system requirements and cost considerations.

The bathymetric data (soundings) are stored together with time and geographical position data to form an original data record (ODR). While the ODR is being generated, a quick look or conventional graphic display is required on the ship to monitor the bottom relief so that the survey plan may be modified as needed. A support ship or tender will be the source of primary positional data through satellite, LORAN, or short-range shore-based location determining devices using radio and radar techniques. The helicopter or boats would then be located by optical or radio means relative to the ship. Laser range finders, radio transponders, and a pelorus, either manual or auto tracking, would be used to follow the boat or helicopter from the ship to develop the location.

Similarly, a towed submerged fish package must be located relative to the ship. This is usually done by a combination of data from cable length, cable angle, slant range to the fish, and short baseline acoustic interferometry to determine the angle to the fish. The fish instrumentation may be augmented with a doppler sonar to measure velocity over the sea bottom to provide dead reckoning data to the ship for the location calculations.

While the bathymetric data are being gathered, they may be telemetered to the ship for real-time perusal. Conventional graphic displays, either hard copy or television, can be used to monitor the bottom relief and assure proper equipment operation. The ODR can also be read and compared simultaneously to assure that the data are being collected properly. The ODR must then be adjusted for cross track position agreement, survey datum reference and sound velocity. The adjusted data now become the experiment data record (EDR).

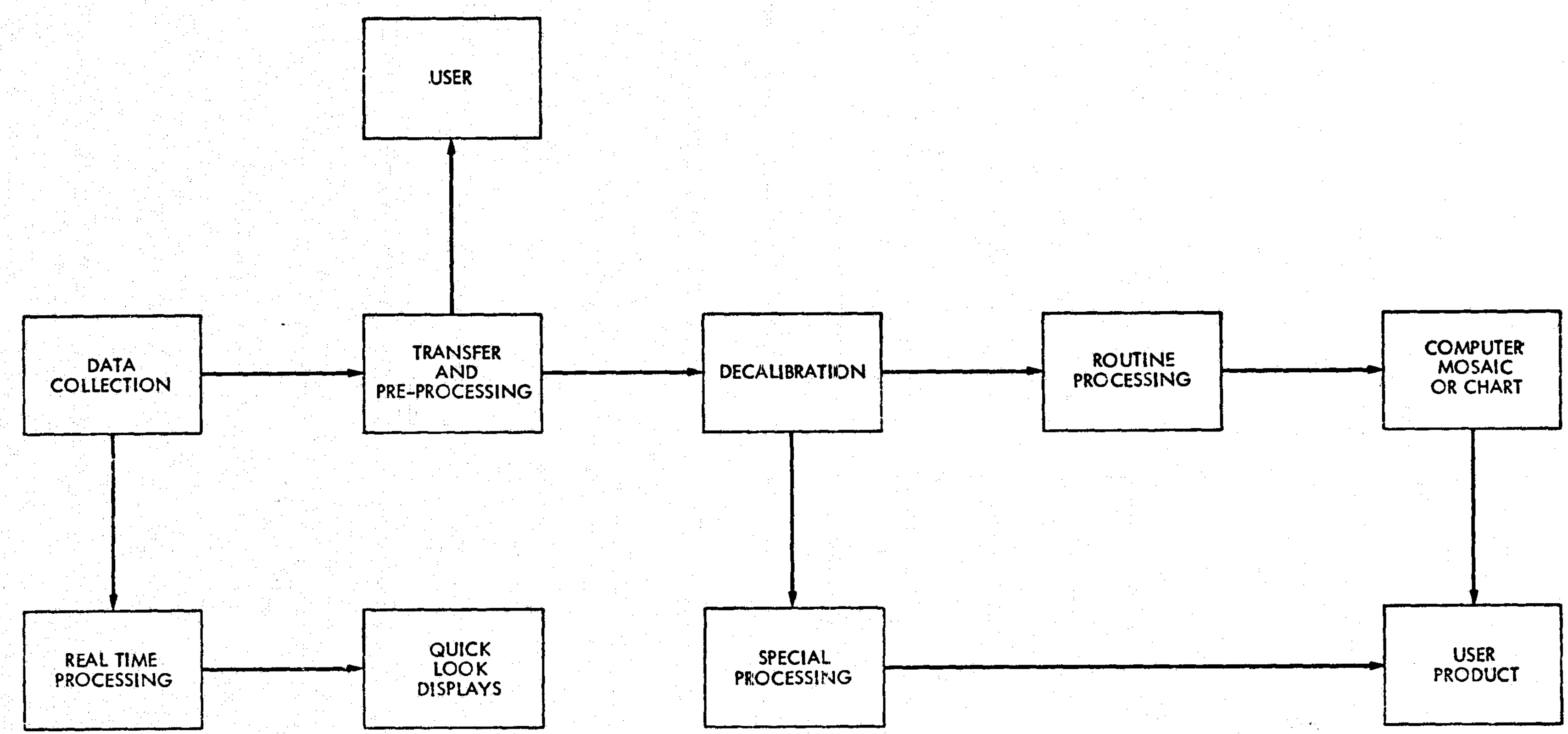

Fig. S-1. System Functional Block Diagram for Sea-Floor Imaging or Charting

b. Processing Sequence for Bathymetric Data

The EDR will be provided to the processing facility on computer-compatible magnetic tape. If so inclined, the user could request data at this point without further processing; however, the option for processing by the system should always be available. (Figure S-2). The data will be cataloged and reformatted depending on the processing required. The routine reduction of bathymetry will be to create geo-coded data-sets and displays. Geo-coded depth data-sets are made by combining the depth sounding (Z) with appropriate navigation data: latitude (Y) and longitude (X). These X, Y, and Z values are inserted into a picture matrix with lines corresponding to X, sample corresponding to Y, and the digital number being the depth measurement Z.

This "depth image" does not have data in all areas due to the sampling of the bathymetry; many "holes" or gaps exist which can be filled by interpolation. The interpolation technique may vary depending on the requirements. Bilinear interpolation could be sufficient; however, more sophisticated estimation can be made. With depth information placed in all parts of the image, any of several kinds of display can be selected. Traditional contour maps, shaded relief maps, and three-dimensional perspective diagrams are all examples of bathymetry displays. The formats for these displays can be photographic prints or transparencies, pen-plots, digital data-sets, tabular listings, or even television monitors. In addition, the bathymetric data could be used to reduce other measurements like gravity, magnetics, seismic records, bottom photography, and side-looking sonars.

2. Imagery Subsystem

a. Data Gathering

The implementation mode for image data collection is the same as fo the bathymetry subsystem; however, it is doubtful that the use of a helicopter for towing is economically practical. The instrumentation required for image data collected consists of side-scan sonars mounted to a ship or boat or a submerged towed fish. The requirement for a height off the bottom not greater than 1/10 to 1/7 of the maximum range usually causes the towed package to be preferred. At depths greater than 30 to 40 meters, ship mounted side scans would be above the optimum height, resulting in poor short-range resolution. There is also less problem with ship-produced acoustic noise when towing the receiver.

The side-scan sonars emit a pulse and then receive a continuum of echoes for a time dictated by the maximum range. Various techniques such as time-varying gain, automatic gain control, and timed suppression of signals are often used to adapt the dynamic range of the sonar signal to the recorder paper. Use of these techniques is to be avoided if the received signals are to be digitized and subsequently processed by digital computer.

The useful dynamic range of a received sonar signal is some 80 to 90 dB, which can be represented by 15-bit digitization in either a fixed or floating point representation. The number of these samples required per sweep is determined only by the range resolution. The rule of thumb of 1 part per 1000 range resolution or 0.3 meters would require a sample every 200 microseconds for a 300-m range. This rate may be relaxed as the along-track

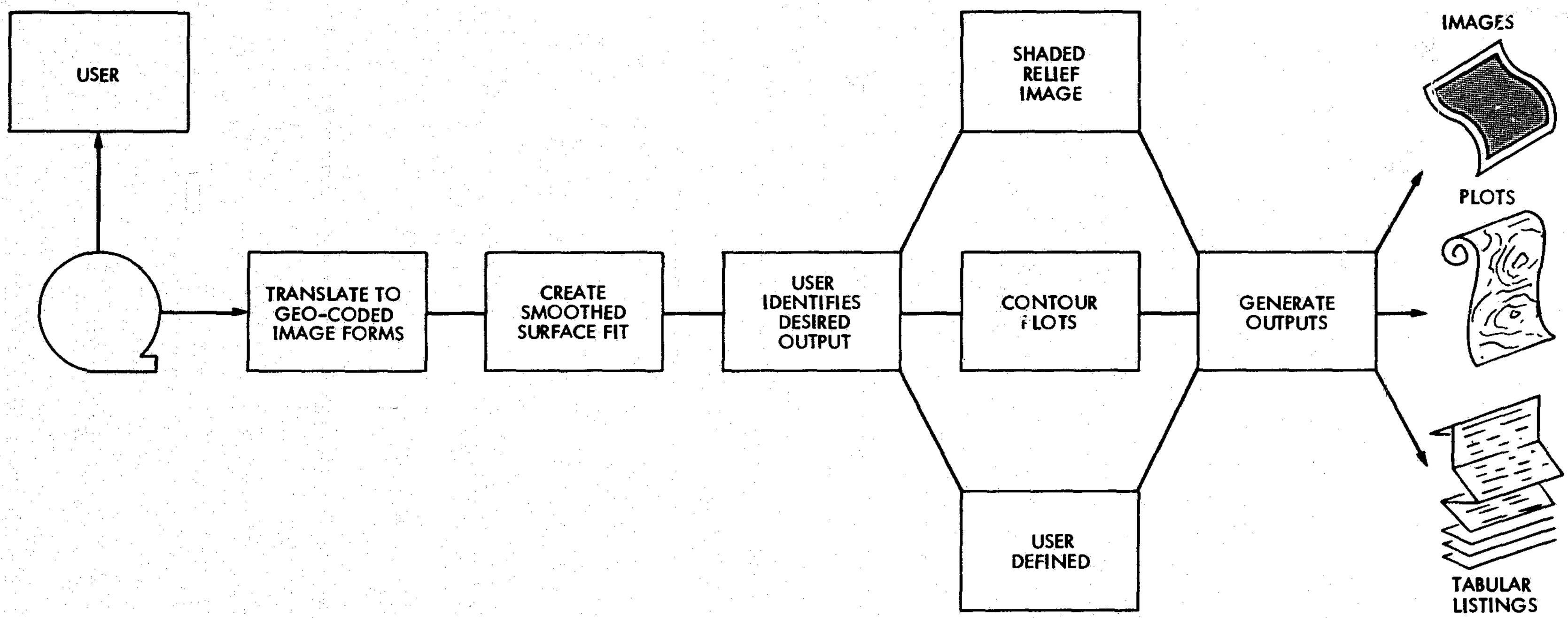

Fig. S-1. Typical Processing of Digital Bathymetric Data resolution is never as good and may be 10 to 20 times worse, so a balance may be had by choosing poorer range resolution. A range resolution of about 60 meters can be achieved with a sample every 40 ms.

The image data are collected and recorded on a graphic recorder and/or analog tape and subsequently digitized on magnetic tape to become the ODR. The digitized ODR must be accompanied by position data and time as in the bathymetry record. Additional data such as made course and over-the-ground velocity are also worthwhile as the short-time turning effects can then be accounted for an removed.

The ODR would be processed aboard ship to correct for slant range, overground velocity, gain, and yawing to generate a quick-look record similar to those produced by present units. The digital magnetic tape bearing all the system corrections becomes the EDR.

b. <u>Processing Sequence for Side-Looking Sonar Data</u>

(1) <u>Nominal Operations</u>. Handling of the side-looking sonar images can be conceived as a five step process (Figure S-3). The first step would be to receive the EDR and to catalog the contents. All ancillary data should be merged into the image records in order to maintain a close temporal association; subsequently, reformatting of the data will be done to separate the images and conform to a standard user-oriented format. At this point, a user could choose to accept the data or pursue further processing by this system.

The second step will involve the removal of image defects due to system characteristics and those imposed by the laws of physics: viewing geoimetries and seawater properties. Here, slant-range correction, ship's speed, heading correction, and signal transmission decalibration can be performed to produce images that are generally usable and free from gross distortion. Again, the user can choose to receive the data now or continue with "in-system" analysis.

Another decision must be made by the user at the outset of step 3. Routine processing of the images will follow in most cases; however, the user may opt for customized sequences of image enhancement. The routine path will be to combine the images with navigation data to allow adjacent swath registration computer matching and mosaicking. Any number of problem-oriented techniques can be selected as part of a special processing sequence. Shading correction, artifact removal, edge enhancement, etc. could be run singly or in chain. Special processing will rely critically on close interaction between the user and the system; in fact, many iterations could occur to achieve desired results. Interpretation undertaken by the user may require such custom processing as map-scale projections, tiepoints registration, mosaicking of adjacent tracks, and specialized problem-oriented techniques.

Map projection of images is the means by which they are reshaped to match a standard cartographic definition of the geoid. For most detailed side-looking sonar work, this will be superfluous. However, peculiar viewing geometries encountered with side-looking sonar may require projection to provide an orthographic scene. Another kind of projection is image resampling

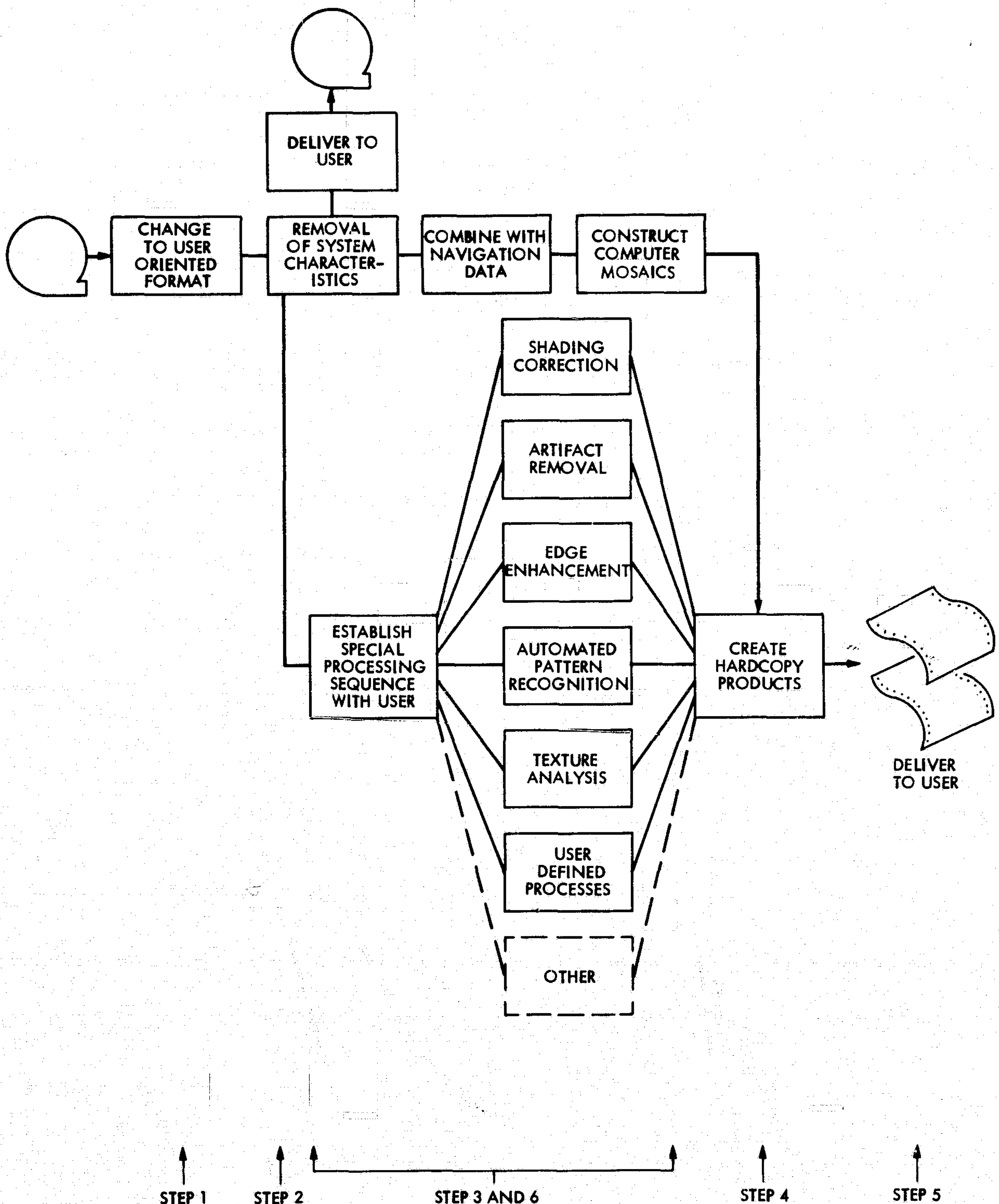

Fig. S-3. Typical Processing of Side-Scan Sonar Data to achieve a convenient scale. This allows correlating individual pixels to unit ground distances.

Tiepoints registration referes to the geometric reshaping of images to force identical features to coincide.

Mosaicking must be done when coverage is needed in excess of single swath widths. Computer-mosaicking can provide a better product than conventional cut-and-paste techniques. Numerical methods of image matching and registration can suppress the borders of picture and impart scene continuity to the eye.

Specialized problem-oriented techniques are the most user-dependent kinds of processing; for example, a structural geologist may want edge enhancement done to accentuate linear features in an image. Complicated and intricate structure in outcrops could show important relationships when the images have been subjected to texture analysis via spatial fourier-transform techniques. If recurring image features can be rigorously identified, automated pattern recognition may speed interpretation and improve results (Andrews, Ref. S-2). An important advantage of computer image analysis is the capability to superimpose and register the side-looking sonar records to other images and data. Superposition and scale matching of side-looking sonar pictures to bathymetric data, sea-floor photographs, coastal Landsat, and aerial images and other geophysical data, such as magnetics, gravity, seismology, could improve the geologist's capacity to correlate sea-floor relief with other measurements.

Regardless of the kind of processing done, step 4 will be required - the conversion of the digital images to hard copy or prints. Prints made from computer-written negatives, pen-plots, ephemeral displays, and even tabular listings are some of the possible hard copy formats. From here, the user can take his products and proceed with his interpretation.

(2) Geo-coded Image Correlation. A constant task of the exploration geologist is to compare, scrutinize, and correlate data of many kinds of measurements with one another. Important structural and geologic relations can be derived from co-parallel analysis of bathymetry, magnetics, gravity, seismic profiles, side-looking sonar, and bottom photography. This method of in terpretation has been traditionally hampered by poorly accessible data which is often not in standard format or map projection. By transformation of all records to pictures with latitude and longitude as independent variables, a geo-coded image is made. A geo-coded image then contains data in terms of latitude and longitude. With this done, contour or relief surfaces of point-value data can be superposed for comparison not only among other point-value data, but also with imagery, like side-looking sonar that has been rectified and registered. The final displat of geo-coded images can be separate relief pictures, each of a single data type, contours, or tabular data. Great imagination and creative endeavor can be enlisted to generate new and innovative ways to display more than a single type of measurement in a picture; this is true for any and all combinations of point-value and image data. Of course, final digital data-sets of all the processing can be made available to many users for do-it-yourself processing.

3. Combination of Bathymetric Data and Sea-Floor Imagery

The sounding records normally taken with side-scan images form a widely spaced contour grid which could assist in the quantitative interpretation of the images. Soundings would also help in the mosaicking by providing slope measurements which would affect the slant range algorithm. In areas where the bathymetry is considered reliable, the taking of soundings while conducting side-scan sweeps can only aid in the confidence of the location or position.

4. Equipment Availability

a. Close-Spaced Bathymetry

The needed depth measuring equipment (precision echosounders) with digital or numeric output is currently available from several manufacturers for ship or boat mounting. This sounding equipment together with a digital data tape recorder with time annotation is the minimum hardware required for the collection of depth data.

Position location to a two sigma of better than 75 meters requires satellite navigation equipment augmented by LORAN-C in a Rho-Rho mode for off-shore bathymetry. Any one of several portable shore-based radio or radar locating systems would be needed for near-shore work. An acoustic transponder array for precise relative location within the survey area might also be needed.

If the bathymetry measurements are to be made with boat or helicopter from the tender, then additional auto-tracking relative distance and angle equipment are needed. Provision for recording this data on magnetic tape is then required for post data-acquisition analysis.

Facilities needed for data processing are a digital computer with about 1 megabyte of main storage and several megabytes of on-line mass storage. Tape drives will be needed as the primary means of data input and output; unit record devices such as card readers and line printers are also needed. Software should consists of a comprehensive set of routines that can easily be invoked in a production environment; one such set is the JPL Video Image Communication and Retrieval System (VICAR) in use at the Image Processing Laboratory (IPL). Cathode-ray tube, T.V.-like, displays that are refreshed from solid-state memories and computer terminals can be used for interactive image processing. Off-line devices such as video-to-film converters and line plotters are also necessary.

b. Side-Scan Sonar

Side-scan sonars with a maximum range of 300 to 400 meters are currently available. These sonars would have to be purchased to a specification calling for elimination of time varying and automatic gain features, provisions for remote keying, analog-to-digital conversion interfaces, and coherent carrier pulsing. The last requirement would facilitate phase measurements of the received signals for texture analysis.

Because of the greater area coverage and correspondingly lower ship operating cost with a sonar of greater range, it appears worthwhile to develop a sonar with about a 2-km range.

Analog-to-digital conversion of the sonar signal and a digital data to magnetic tape interface would require a brief design and development effort. Magnetic tape data storage equipment would be needed as well as a control microprocessor to key the sonar(s) and time and annotate the conversion process and received signals.

Position determination and location equipments would be required as in bathymetry. Slant range and direction to a towed sonar "Fish" from the ship must also be determined, requiring a short-baseline acoustic interferometer and transponder.

There are two requirements for handling the data from side-scan sonar. The first is the "quick-look" display aboard ship for ascertaining proper operation. This would require a TV or permanent record display which would present the side-scan returns (with or without slant range and ship speed corrections) as an intensity-modulated distance versus swath range display. The current form of output - brown, electro sensitive wet paper - has minimal dynamic range and rapidly deteriorates (Paluzzi, et al., Ref. S-3). Replacement of this media with a continuous strip, Xerox-like record, would be a major improvement. The use of high-density digital tapes can reduce physical data-handling operations and attendant problems.

The second data-handling requirement, for post-acquisition processing, would require equipment like that described for bathymetry.

VI. Recommendations

If there is sufficient interest in the concepts, a demonstration system should be developed, assembled, and tested at sea. The resulting data should be digital processed by the methods discussed above and the system performance evaluated.

An existing side-scan sonar augmented by digital recording would be used for the demonstration and existing NASA developed imagery software used for trhe processing. Promising results would then lead to the development of a longer range sonar with integral quick-look and digital recording features.

A bathymetry demonstration would be implemented by contracting for a very close-spaced survey utilizing an existing echosounder and precise navigation techniques. The data would be processed by contour generating routines and also relief map software presently available. The utility of these types of charts in adequately presenting topographic data would be assessed.

Both demonstrations can be conducted concurrently and concluded in 18 months. This time period includes 1 year for the development of the integral side-scan sonar.

Therefore, a fully integrated system for imaging and mapping of the sea floor may be designed, assembled, tested at sea, and made operational for oil and gas exploration work.

It is recommended that a working group of interested users form the oil exploration community be named as advisors to the demonstration project. The group can help guide the project by making suggestions and inputs in generation of system requirements and the desired end product. Persons selected for the working group should be geologists, geohpysicists, exploration managers, and operations engineers from the oil exploration industry.

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APPENDIX T

POSSIBLE METHOD OF ECONOMIC EVALUATION OF NEW TECHNICAL CONCEPTS

As part of this study, an economic evaluation of the various technical concepts was desired. One approach considered is outlined in this Appendix. Though the method seemed desirable, time and money constraints did not permit its use. It is recorded here, in its partially developed state, in the thought that it may be of use in the future.

I. EVALUATION MODEL

Several elements are essential for the successful implementation of the evaluation model. They involve interaction between people of various expertise, such as between people with background in technical engineering, geology or geophysics, and statistics. The process can best be illustrated by the flow diagram shown in Figure T-1.

A technical team will develop a new system concept. The basic output of the system - improved system performance - will be expressed by the team chiefly in terms of system parameters, (e.g., energy produced, burn rate, frequency spectrum, etc.). In that form, the output can have little impact or relevance to the ultimate measure of dollar value. As the second box in the progression shows, the system parameters must first be interpreted by a geophysicist or another person with such capabilities who can make a translation of the "raw data" into such things (in the case of a new source), as the most likely depth (or range of depths) of penetration of the signal into the geological substructure and the resolution obtainable. For example, a new seismic source may offer an increased energy output. That increase could be used either to increase the frequency and hence resolution or to increase the depth of penetration - or both. Together with the technical engineers, the geophysicist would attempt to determine which of the three above cases the system would fall into - increased depth, increased resolution, or both. But they would not stop there - having made that determination, the combined group would quantify the reachable depths and/or attainable resolutions.

With this information, a geologist (Box 3) would be in a good position to describe the set of features (classified by type, depth, and thickness) that could then be "seen" or discerned by the new system. This set of features, which include more than the set using the existing seismic systems, would then define the universal set of features that could be seen. It is important to bound this set because later in the evaluation model, probability of occurrence will be assigned to each of the features. This will be discussed further in Section II.

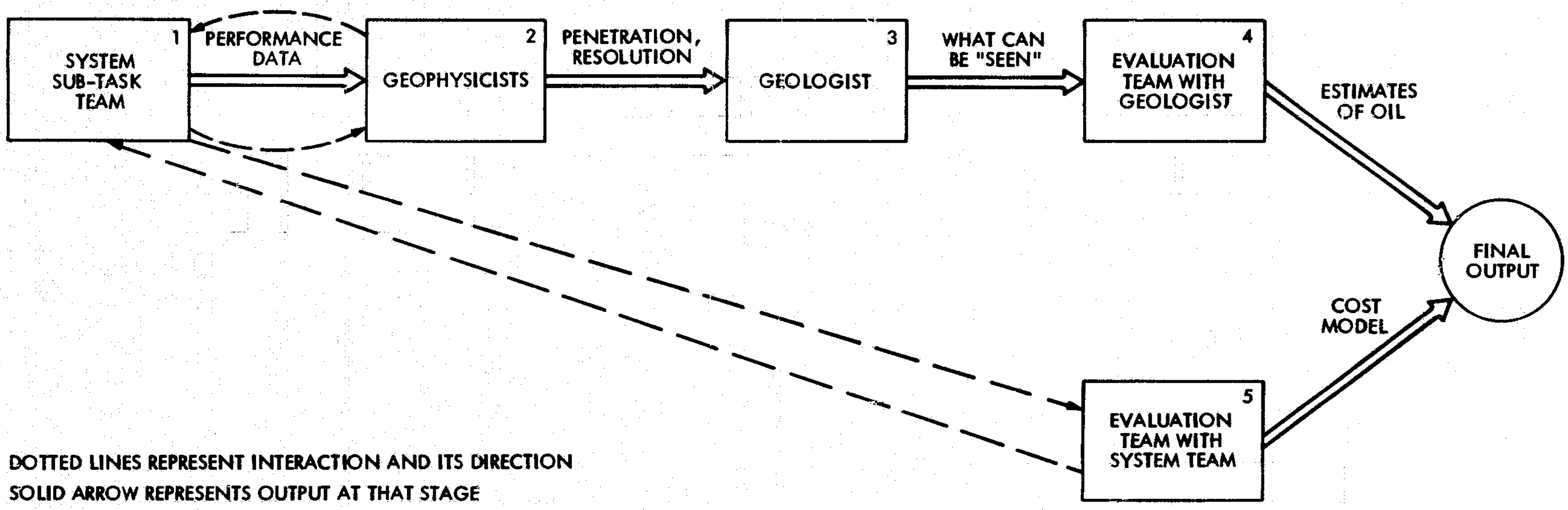


Fig. T-1. Flow Diagram of Economic Evaluation Model

In Box 4, the geologist, in conjunction with the statistician and others working on the evaluation model, will interact to derive the geologist's best estimates of the amount of oil contained underground, if any. These assessments will then be "plugged into" the model and in the manner demonstrated in Section II, the analysis is carried through, taking into account the uncertainties, decision making, benefits and costs. In the model, the geologist's assessments are the probabilities of the particular feature occurring. The importance of a new system can be seen. Features yielding high payoffs but not "seen" by previous systems were previously weighted with a factor of zero; however, since the new system can now see a new feature, the feature's payoff is now multiplied by the probability of occurrence and thus a higher total expected reward results.

From the above discussion it becomes clear what is needed, namely:

1) Each concept team will need to provide the geophysicist or other appropriate specialists (who may be members of the team) with performance data for the particular system;

2) Each concept team will need to interact with the geophysicists to determine how performance data translate into meaningful geophysical information and what that information will actually be.

3) The technical engineers will have to provide the evaluation group with the information needed to build an operations and maintenance cost model. For this, input requirements in terms of manpower, supplies, auxiliary equipment, fuel, etc. have to be specified. Differences in cost between the new and existing system will have to be outlined.

4) Geologist will need to define an appropriate scale of geological features or occurrence that are good indicators of oil and which can be detected by the proposed systems.

5) After the above scale is defined, the geologist will need to assign probabilities of occurrence to each of the entries on the scale (based on observed frequencies or theoretical considerations, etc.)

[Items 4) and 5) essentially combine to form a geological model of the subsurface geology to be used for the purposes of analysis.]

6) Geologist, in this case now interacting with the numbers of the evaluation sub-task, will need to provide estimates on the impact of the additional information (gotten from the improved system) on the probability of finding oil. It is to be noted that the geologist need not directly derive the probability assessments; rather, he may be questioned, and his subjective judgements will be "extracted" and then put into the form of a probability distribution.

As can be seen from the above detailed listing, interaction between the various experts is necessary in the ways outlined above. The engineering and technical judgements are best made by those members of the technical team with whom the new system originated. What the new system can then do under the ground is best determined by geophysicists or a person with similar capabilities, working with the technical group. The formulation of an appropriate model of subsurface composition (structures and relative frequencies) is best done by a geologist. Finally the probability estimates (or "the encapsulation of the geologist's subjective judgements in the form of a probability distribution") will be derived in an interaction between chiefly the geologist and the evaluation team. Also, it should be noted that for the cost aspect of the model, information pertaining to the systems operation and maintenance, such as manpower, equipment, supply and fuel requirements etc., will need to be specified. The cost of operations and maintenance for the existing system needs to be modeled also so that a comparison can be made between the old and the new system.

II. EXAMPLE OF METHODOLOGY

The following contrived example illustrates the methodology and is based to some extent on C. Jackson Grayson's early work, Decisions Under Uncertainty: Drilling Decisions by Oil and Gas Operators (Ref. T-1).*

Petro Explo, a small company specializing in the exploration for petroleum, has received the rights to drill at a particular location. Before drilling, seismic tests can be run if they are deemed worthwhile. Thus, a decision has to be made: Should Petro Explo make a seismic test or should Petro Explo not make a seismic test? A consequence of this decision is the question of how a seismic test should be judged "worthwhile".

Later, when investigating the available seismic systems, Petro Explo found that currently there were only two systems available - SEISMO I and SEISMO II. SEISMO I was a commonly used technique that yielded fair results; whereas, SEISMO II was a new technique that gave vastly better output. As expected SEISMO II would cost more to use than SEISMO I. Thus, the decision now facing Petro Explo was whether to make no test, make seismic test I (SEISMO I) or seismic test II (SEISMO II). This decision can be represented diagrammatically and is done so in Figure T-2.

O. L. Field, the president of Petro Explo, realized that the idea was to determine which system to use before any money was actually spent for a test. Field pondered the questions, "Which system would be better?", "What would we expect to see?" After a brief period, he realized he was unable to make pertinent judgements and summoned the company geologist.

After a lengthy discussion together, it was determined that the systems could see three features: anticlines, stratigraphic traps, and reefs. For each one of these three, they created two categories - "greater than 150 feet" and "50 - 150 feet" - to differentiate the different capabilities of SEISMO I and SEISMO II. Thus, six groupings were made (Assumption 1). Field and the geologists realized that the new system would enable them to see smaller structures and also to see more of the structures that could be seen by the old system (i.e., structures greater than 150 ft.) These additional structures would lie at depths greater than the old system could "see."

*References are listed at the end of this appendix.

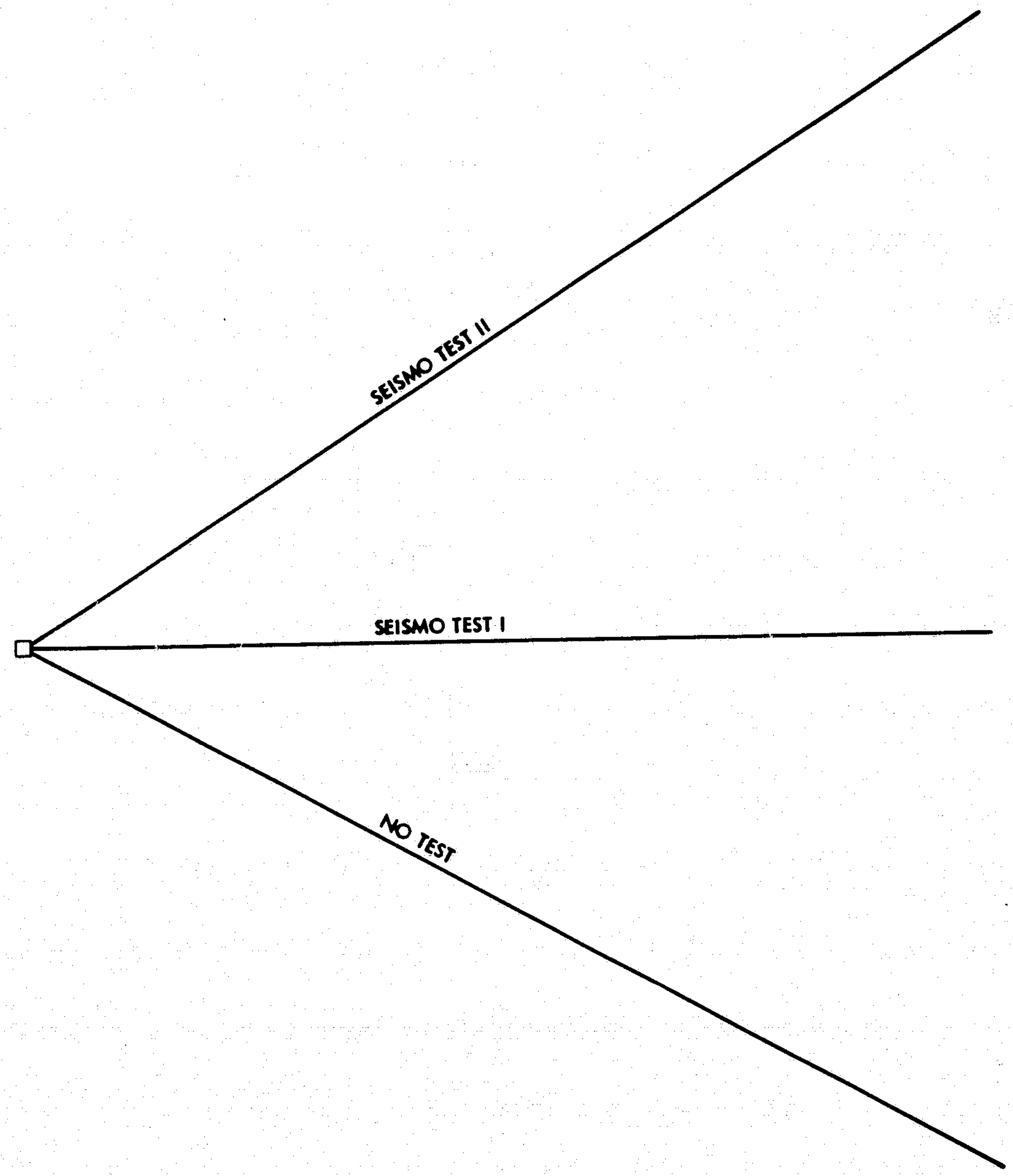


Fig. T-2. Decision Scheme

Realizing further that the problem inherently contained a lot of uncertainty, they knew their only recourse was to rely on probabilities.

Thus, the ability "to see smaller structures and also to see more of the structures that could be seen with the old system" would be reflected in higher probabilities of seeing structures for the new system.

The problem at this point appeared to be extremely complicated, and so it was decided to simplify it in the following way to make it tractable: if several structures occurred in combination, only the "most important" structure would be considered in the analysis. To make that determination, the geologist using his best judgement decided which of the structures were most important and arranged them in an order as follows (Assumption 2):

A. DOMINANT GEOLOGICAL FEATURES (in increasing order of importance)

reef	> 150 ft ($\sim S_1$)
strat trap	> 150 ft ($\sim S_2$)
reef	50-150 ft ($\sim S_4$)
strat trap	50-150 ft ($\sim S_5$)
anticline	> 150 ft ($\sim S_3$)
anticline	50-150 ft ($\sim S_6$)

Again using his past experience and theoretical considerations the geologist derived a set of probabilities to be used by himself and Field. They are given in Table T-1 (reference Assumption 3).

Table T-1. Probability of A Structure Occurring (i.e., being dominant): Example

Depth	Type of Depth	Anticlines	Stratigraphic Traps	Reefs
greater than 150 ft	old depths	.20	.25	.25
	new depths	.02	.03	.01
between 50 and 150 ft	old depths	.02	.04	.04
	new depths	.01	.01	.02

Above probabilities sum to .9, leaving a probability of .1 that no structure will occur.

Thus, if and when a test was made, this table would give the probability of a particular result occurring (i.e., "seeing" a particular structure).

The decision tree representation of the situation up to that point is shown in Figure T-3. The S-symbols in that figure are a shorthand notation used to describe the occurrence of a particular feature. This notation is defined in Table T-2. The decimal numbers between zero and one were just the probabilities calculated from Table T-1. For example, if SEISMO II is used, the probability of S_3 (an anticline greater than 150 ft) is the sum of the probabilities in Table T-1 for anticlines greater than 150 ft at old depths (0.20) and at new depths (0.02). The sum, 0.22, is entered on the S_3 line for SEISMO II in Figure T-3. SEISMO I provides information at old depths only, so the probability entered on the S_3 line for SEISMO I (Figure T-3) is just the old depth value, 0.20. SEISMO I gives no information on features smaller than 150 ft, so for S_4, S_5, S_6 (all features smaller than 150 ft), the probability entered for SEISMO I (Figure T-3) is 0.

Table T-2: Examples of Symbols Selected for Feature Occurrences

S_0	Seismic data of little value
S_1	Seismic data indicates a reef with thickness > 150 ft.
S_2	Seismic data indicates a stratigraphic trap with thickness > 150 ft.
S_3	Seismic data indicates an anticline with thickness > 150 ft.
S_4	Seismic data indicates a reef with thickness 50 - 150 ft.
S_5	Seismic data indicates a stratigraphic trap with thickness 50 - 150 ft.
S_6	Seismic data indicates an anticline with thickness 50 - 150 ft.

At this point, Field and the geologist started to ask a lot of "what-if?" questions: "What if the new test yields S_3?, What will that do for us?" They realized that if they proceeded with a seismic test, they would essentially be purchasing information. What was this information worth?

This aspect was beyond them so a decision analyst was brought in to work on the problem. The problem was similar to others the analyst had encountered. There was lot of uncertainty in the form of chance outcomes dependent on what decision was made. To get to the issue of "ultimate economic value," the size of the oil field was taken to be the best indicator. Since this was as yet an undetermined and uncertain value, a probability distribution was used to incorporate and reflect the decision maker(s) best estimates of the size of the field.

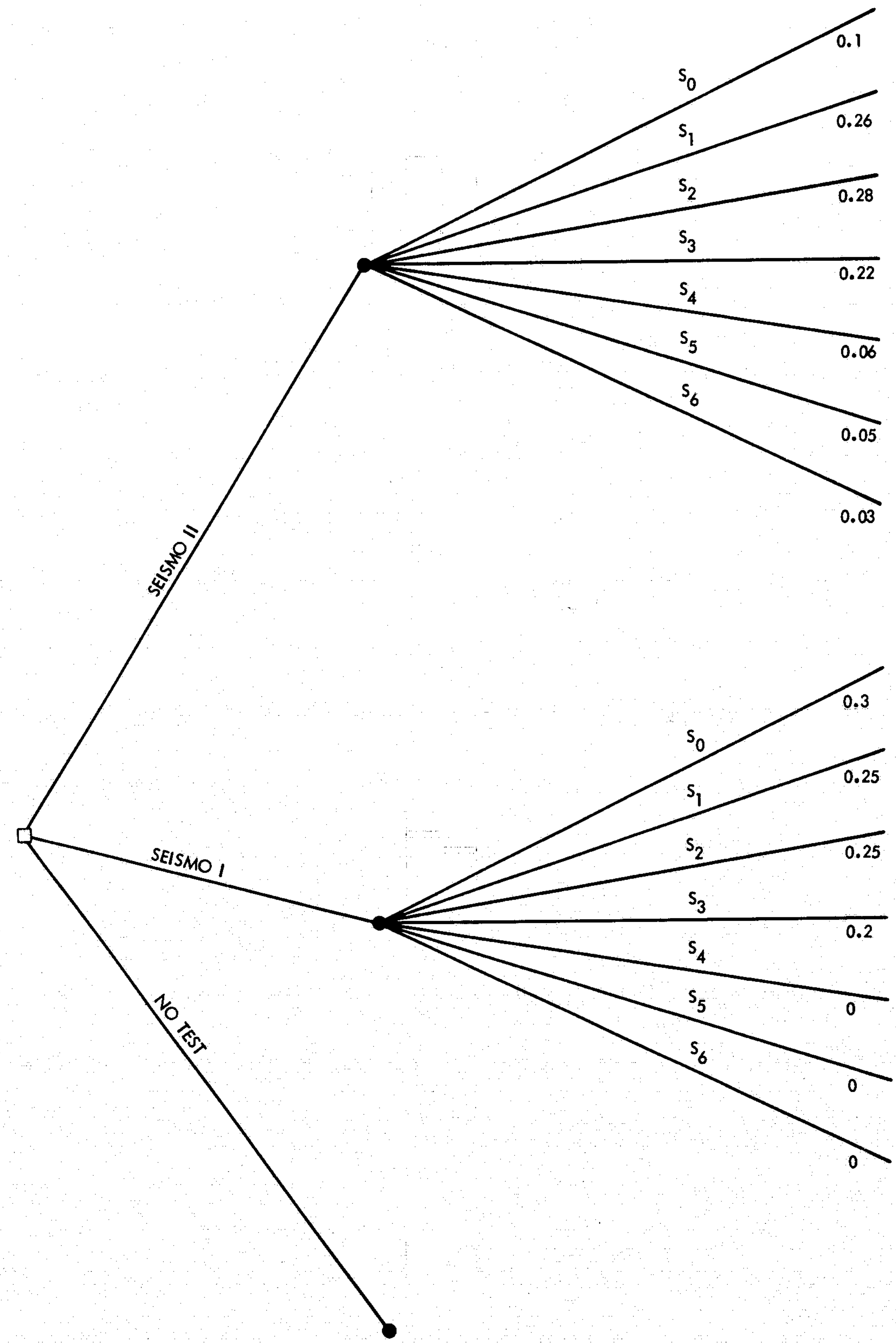


Fig. T-3. Decision Tree Representation

Later, if and when a test was run, the information received from the test could be used by the decision maker to revise or update his probability distribution.

To simplify the analysis again, it was decided that an oil field could be characterized by three findings: zero (dry hole), 200,000 barrels, and 500,000 barrels. (Assumption 4). The payoffs associated with these three findings are assumed to be, respectively, a $500,000 loss, a $1,300,000 gain, and a $4,300,000 gain. (These are just arbitrary values and not representative.) The probability distributions mentioned above were simply the probabilities that the prospect contains a field of those sizes. For example if those probabilities were .7, .2, and .1 for a dry hole, a 200,000 barrel field, and a 500,000 barrel field, respectively, the distribution would be tabulated as and shown diagrammatically in Figure T-4.

Field Size	Probability of Occurrence
Dry Hole	.7
200,000 bbl.	.2
500,000 bbl.	.1

At that time, the analyst made a key point: since it is not known which event will occur, it is logical to weight each event by the likelihood of its occurrence, to provide a "weighted value" for the outcome or "expected value," as the analyst referred to it. Thus, whenever a choice had to be made between several acts (which would result in uncertain outcomes), the expected value of the consequences (arising from the act) would be used to evaluate that decision, and the act yielding the highest expected value would be chosen (Assumption 5).

Thus, there was now a way to evaluate a given decision: given the probability distribution, each outcome would be weighted by the probability of occurring and summed to yield the expected value talked of above.

Field was a bit confused: "What if we don't drill a hole - how does expected value fit in then?" The analyst replied that, if in fact, a test had been made, and then the decision to not drill was made, then Field would be faced with a certain (probability one) payment, C, for the seismic test - which would represent an expected value cost of just C. (C_0 for SEISMO I and C_1 for SEISMO II.)

So, the option of not drilling after the seismic test could be represented on the decision tree by the addition of Figure T-5. Each of the branches could represent a particular result of the seismic test. The complete tree then could look as is shown in Figure T-6.

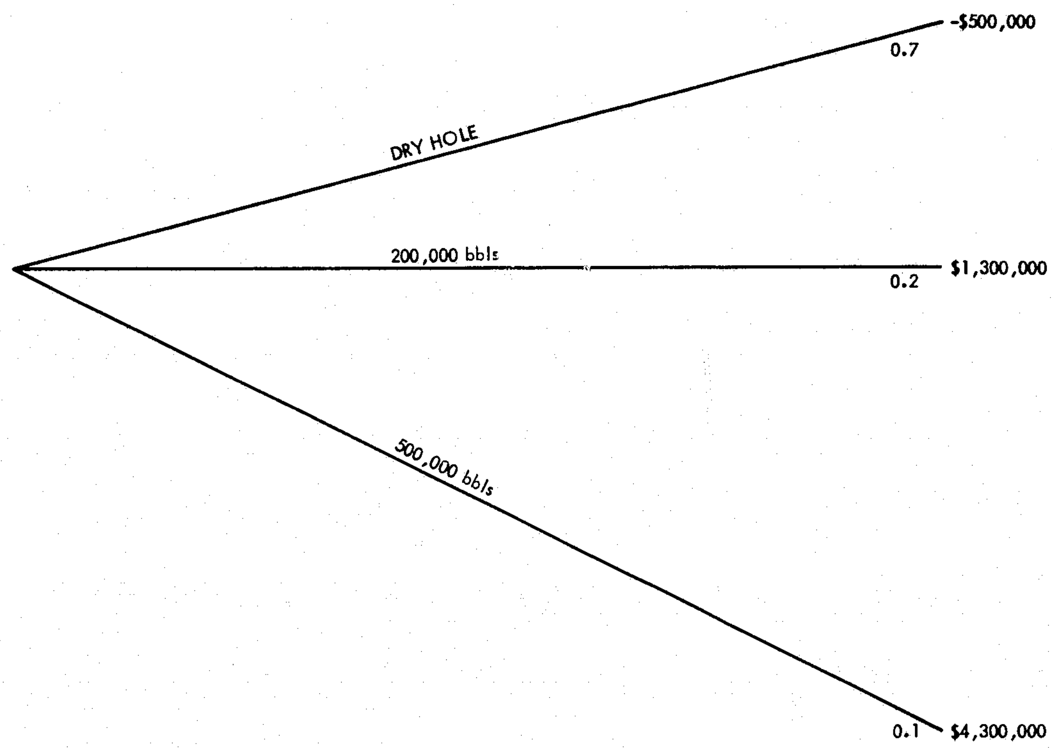


Fig. T-4. Scheme for Three Values of an Oil Field

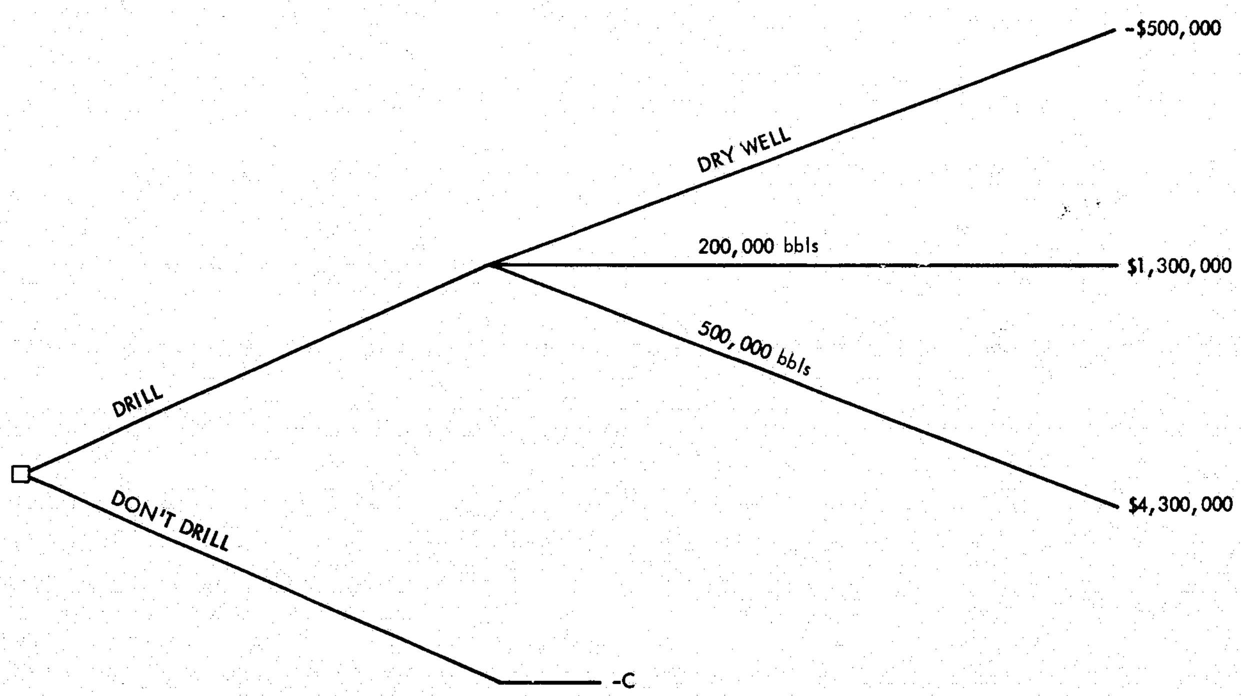


Fig. T-5. Decision Tree Options

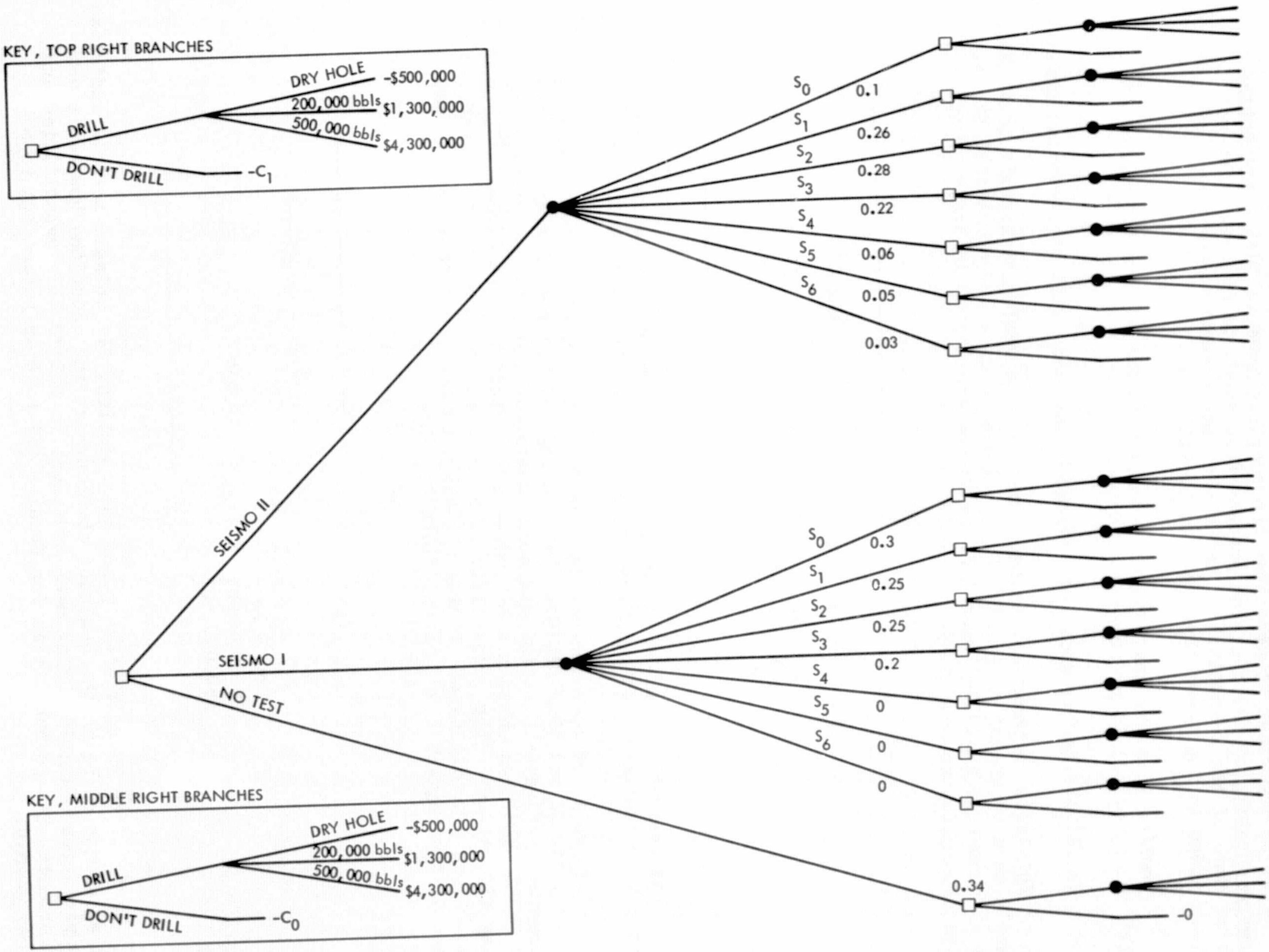


Fig. T-6. Interim Decision Tree: Example

It is important to note that the complete tree is just a sequential representation of the decision process from start to finish. Also notice that some of the probabilities and all of the expected values have not yet been added to the tree; they need to be filled in.

Working with the analyst, the geologist's subjective judgements for the amount of oil in place were elicited.

To illustrate the updating procedure, one case will be recreated here.

Initially, without any seismic results, the geologist thought that there would be a .7 chance of a dry hole, a .2 chance of a 200,000 barrel field, a .1 chance of a 500,000 barrel field at the designated location. Note the probabilities sum to one:

	No Test
Dry Hole	.7
200,000 bbl	.2
500,000 bbl	.1

The analyst then asked the geologist "Suppose we used seismic test I and got an indication of S_3. How would you judge the chances then?"

The geologist considered this. He felt that S_3 was a very good indicator of trapped oil and thus decided that finding oil was more likely with such a structure, However, he did have some reservations about the accuracy of SEISMO I, and thus while his estimates of finding oil were higher than before, they did not drive the probability of a dry hole to zero. That was reduced to .2; the probability of finding a 200,000 barrel field rose to .45, and that of finding a 500,000 barrel field to .35:

	No Test	SEISMO I
Dry Hole	.7	.2
200,000 bbl	.2	.45
500,000 bbl	.1	.35

Lastly, the geologist was posed the question, "If seismic test II indicated the existence of S_3 as the dominant structure at the location, how would your probabilities change?" Being more confident in SEISMO II's capabilities and performance, his probabilities for finding oil rose as before but to even higher levels.

For this indication, the geologist associated a .5 probability of finding a 200,000 barrel field, a .4 probability of finding a 500,000 barrel field, and consequently a .1 probability of encountering a dry hole:

	No Test	SEISMO I	SEISMO II
Dry Hole	.7	.2	.1
200,000 bbl	.2	.45	.5
500,000 bbl	.1	.35	.4

In a similar fashion, the remaining assessments were considered by the geologist and elicited from him yielding the probabilities listed in Table T-3 and the final decision tree shown in Figure T-7.

Using the completed tree, the analyst carried through the analysis. From the probabilities on the tree and the payoffs shown for the three possible ultimate findings, he calculated the expected value for each of the choices. These expected value are shown in Figure T-7. The expected value of choosing SEISMO II is \$1,400,000 minus 0.1 x C_1. Since C_1 would be about \$50,000, this expected value is about \$1,395,000. For SEISMO I the expected value is \$820,000 and for no test \$340,000.

Thus, Field, being an "expected value" decision maker (Assumption 5) decided to use SEISMO II, as it yielded the highest expected payoff.

ASSUMPTIONS (Refer to Table T-3.)

1) That the subsurface geology can be adequately described (in terms of finding oil) by the following features: anticlines, stratigraphic traps, reefs (all greater than 150 ft) and a similar group between 50 - 150 ft., making a total of six groupings.

2) That a hierarchy of the above structures can be established (in terms of importance as indicators of oil) and that in process of judging the chance and amount of oil, only the highest ranked structure is relevant for the determination. Essentially, this means that only one structure occurs. In the event of combination of features, the "best" one is chosen to be the one that solely exists.

3) That relative frequencies of the above groupings can be derived, yielding a model of subsurface geology for a "representative" field.

4) That, for this example, an oil field can be adequately described over its range of values by the following three discrete values: (1) dry hole, (2) 200,000 barrel hole, (3) 500,000 barrel hole. Furthermore, that the payoffs associated with the three events are respectively: (1) \$500,000 loss, (2) \$1,300,000 gain, (3) \$4,300,000 gain. That the cost of operating and maintaining the

new and existing systems per well have previously been determined to be C_1 and C_0 respectively.

5) The decision maker in this example makes decisions based on expected value.

Table T-3. Estimates of Probabilities of Each Possible Ultimate Finding, Given Various Information About the Prospect

Prior Probability Mass Function on Field Size

Field Size	Probability of Occurrence
dry hole	.7
200,000 bbl.	.2
500,000 bbl.	.1

Posterior Probabilities Given S_0

Field Size	S_0 From Old Seismic	S_0 From New Seismic
dry hole	.8	.83
200,000 bbl.	.15	.14
500,000 bbl.	.05	.03

Posterior Probabilities Given S_1

Field Size	S_1 From Old Seismic	S_1 From New Seismic
dry hole	.6	.5
200,000 bbl.	.25	.3
500,000 bbl.	.15	.2

Posterior Probabilities Given S_2

Field Size	S_2 From Old Seismic	S_2 From New Seismic
dry hole	.5	.4
200,000 bbl.	.3	.35
500,000 bbl.	.2	.25

Table T-3. (contd)

Posterior Probabilities Given S_3

Field Size	S_3 From Old Seismic	S_3 From New Seismic
dry hole	.2	.1
200,000 bbl.	.45	.5
500,000 bbl.	.35	.4

Posterior Probabilities Given S_4

Field Size	S_4 From Old Seismic	S_4 From New Seismic
dry hole	.4	.3
200,000 bbl.	.35	.4
500,000 bbl.	.25	.3

Posterior Probabilities Given S_5

Field Size	S_5 From Old Seismic	S_5 From New Seismic
dry hole	.3	.2
200,000 bbl.	.4	.45
500,000 bbl.	.3	.35

Posterior Probabilities Given S_6

Field Size	S_6 From Old Seismic	S_6 From New Seismic
dry hole	.1	.05
200,000 bbl.	.5	.55
500,000 bbl.	.4	.4

III. ADDITIONAL DEVELOPMENT

The economic evaluation of the various proposal systems is not a trivial task. The elusive elements of uncertainty, the usefulness of new information, and the ultimate economic values have to be taken into account. To adequately handle these elements, we chose a "decision-theoretic" model.

To construct the actual model, we decided to work through the details of one specific site, the Powder River Basin in Montana. A specific site

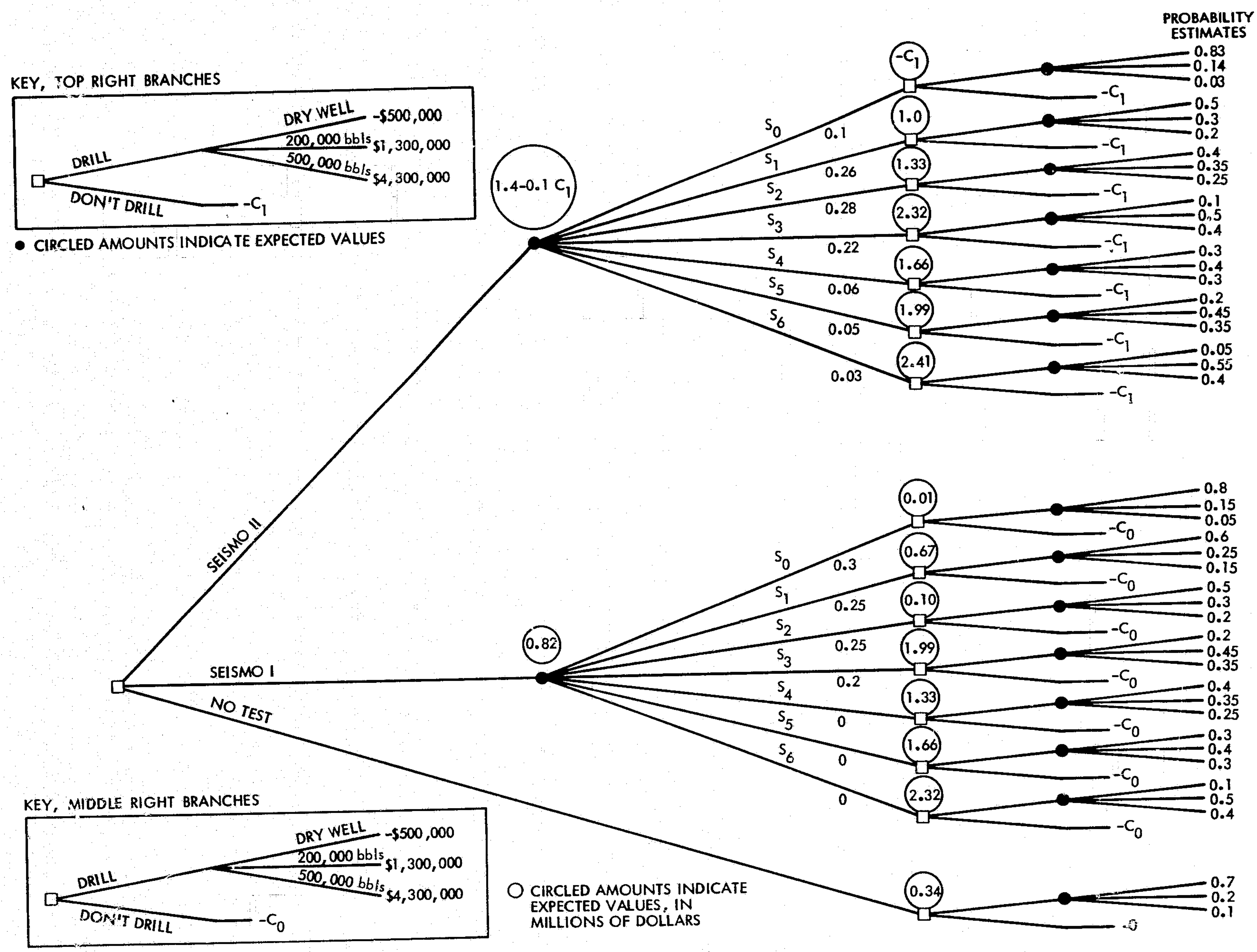


Fig. T-7. Final Decision Tree: Example

was chosen to demonstrate the operability/feasibility of the model and to gain insights into its essential characteristics.

Key to the development of the model was the interaction of the evaluation team with a geologist who could provide the necessary geological judgements pertaining to the structure and validity of the overall model and to the specific information pertaining to the chosen test case site.

A geologist member of the study team verified the appropriateness of the decision-theoretic framework. He typified the Powder River Basin area as an old delta with the dominant geological feature being "stratigraphic traps," thin beds of sand (typically between 0-40 ft.) sandwiched between and among other layers, such as shale. The sandbars are potential oil-and-gas-bearing strata, and thus their detection is useful in the search for petroleum.

Given this information, we formulated the first part of the model as a search problem. Many models in search theory exist in the literature, and an appropriate one was found and adapted to fit the characteristics of the Powder River Basin. As will be discussed in the second half of the memo, the model yields a probability distribution of the number of sandbars found and their sizes. The probability of finding a particular sandbar would be a function of sandbar thickness and the level of search effort (in terms of miles of seismic test).

All of the above elements would be fitted into the decision tree at the appropriate time and the results derived. Most of our work has been applied to the problem of adapting the search model to the problem at hand. The model as developed thus far will now be outlined.

A. NOTES ON A MODEL FOR THE SEARCH PROCESS

1. Model Assumptions

The search-theory problem considered (Ref. T-2) is characterized by the following elements: (a) objects: the objects (sandbars) of the search are immovable and passive in nature and are characterized by volume (area and thickness); (b) search area: a search area possesses an unknown number of objects (sandbars) of differing sizes. There may be several distinct areas each with its own set of objects (sandbars); (c) search process: the process of searching in an area is a sequential one characterized only by the level of effort applied in the area and not by its spatial distribution; (d) search effort: the search is characterized by the number of miles of conducted seismic prospecting. The results of a seismic effort are characterized by failure or the discovery of a set of objects (sandbars). The essential probabilistic property of the search process is that the probability of discovery of an object (sandbar) on any trial is proportional to the thickness of the object (sandbar).

2. Statistical-Decision Theory Concepts (see Figures T-8 through T-10)

Some important concepts and terms of statistical decision theory, as presented in Ref. T-3, are utilized by our model. The term unknown state of nature represents the conditions that are true but unknown about the objects of ultimate concern (sandbars). The prior distribution is a probabilistic description of the unknown state of nature at some point in time prior to some future search effort. The mode of the <u>conditional search process</u> specifies the probabilities of the various search outcomes conditional upon the state of nature. Bayes' theory is then used to determine the <u>posterior</u> distribution of the state of nature after the outcomes of the search are observed.

3. The State of Nature for a Search Area

The features of a search effort that are of direct concern are the number and sizes of the objects (sandbars) in the search area. We characterize the unknown state of nature by

N: the number of undiscovered objects (sandbars) remaining

v_i: the size of the i^{th} undiscovered object

The number of objects N present in a search area is a nonnegative integer with no obvious upper bound. The probability distribution of N is Poisson and is denoted by

$$P(N|\lambda A) = \frac{(\lambda A)^N e^{-\lambda A}}{N!} \qquad N = 0, 1, 2, \ldots$$

The parameter of this distribution is λA where λ represents the mean number of objects per unit of search area and A is the number of units of search area.

We assume that the size of the i^{th} object (sandbar) is gamma-distributed and is denoted by

$$f(v_i|b, c) = \frac{c(cv)^{b-1}e^{-cv}}{\Gamma(b)} \qquad v_i > 0$$

If we let $\tilde{\underline{v}} = (\tilde{v}_1, \tilde{v}_2, \ldots, \tilde{v}_n)$, the joint distribution of $\tilde{N}$ and $\tilde{\underline{v}}$ is the product of a probability function of N times a product of N independent density functions of identical form. Therefore, the prior distribution of the unknown state of nature is

$$P(N, \underline{v}|\lambda, b, c) = \frac{(\lambda A)^N e^{-\lambda A}}{N!} \prod_{i=1}^{N} f(v_1|b, c)$$

4. The Search Effort

The outcome of the search can be described by

n: the number of objects discovered

$\alpha = (\alpha 1, \alpha 2, \ldots, \alpha n)$: the sizes of n objects

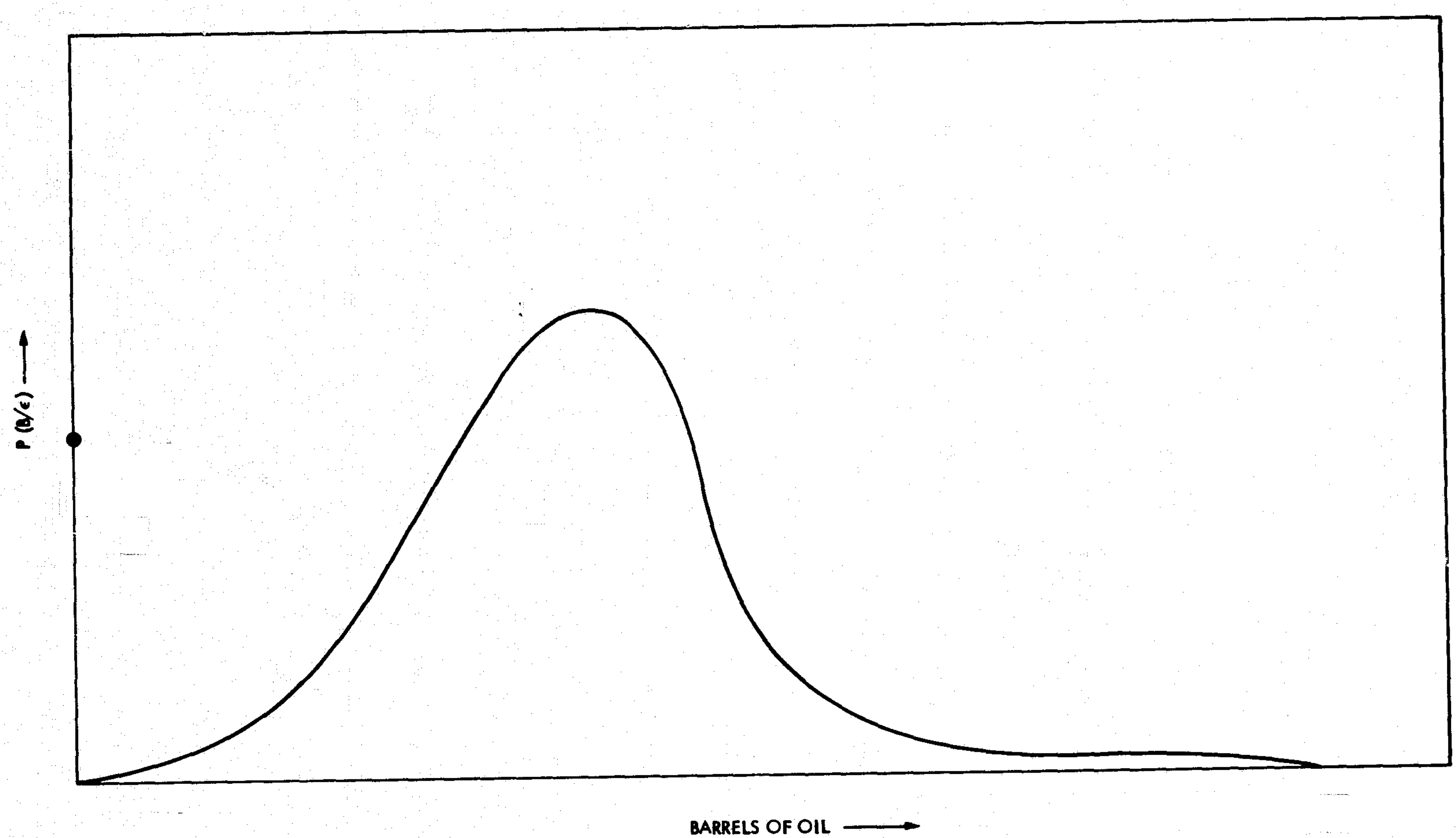
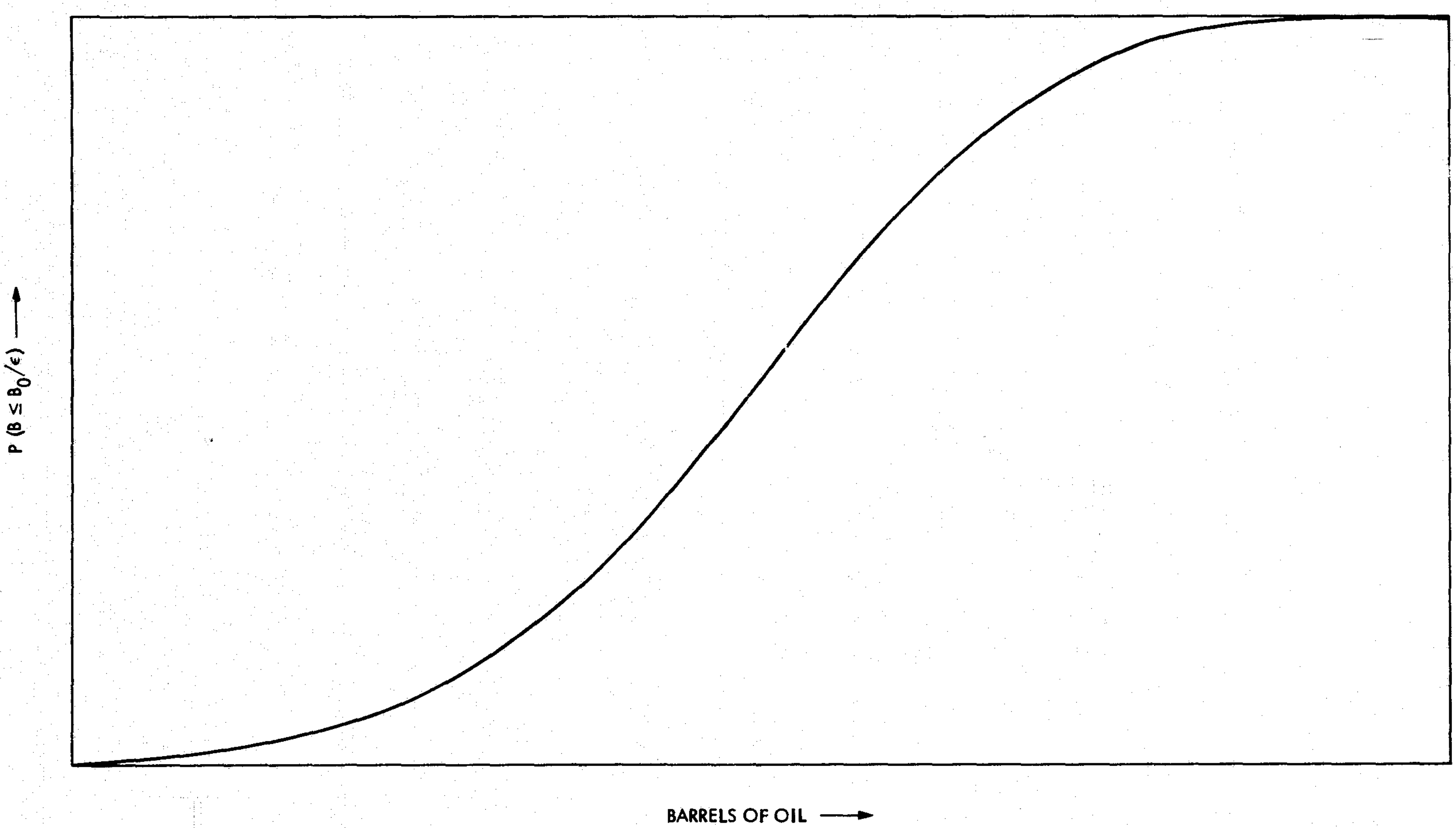


Fig. T-8. Prior Probability Density Function on Field Size



$$P(B \le B_0/\epsilon) = \int_{-\infty}^{B_0} P\,(B/\epsilon)\, dB$$

Fig. T-9. Cumulative Density Function

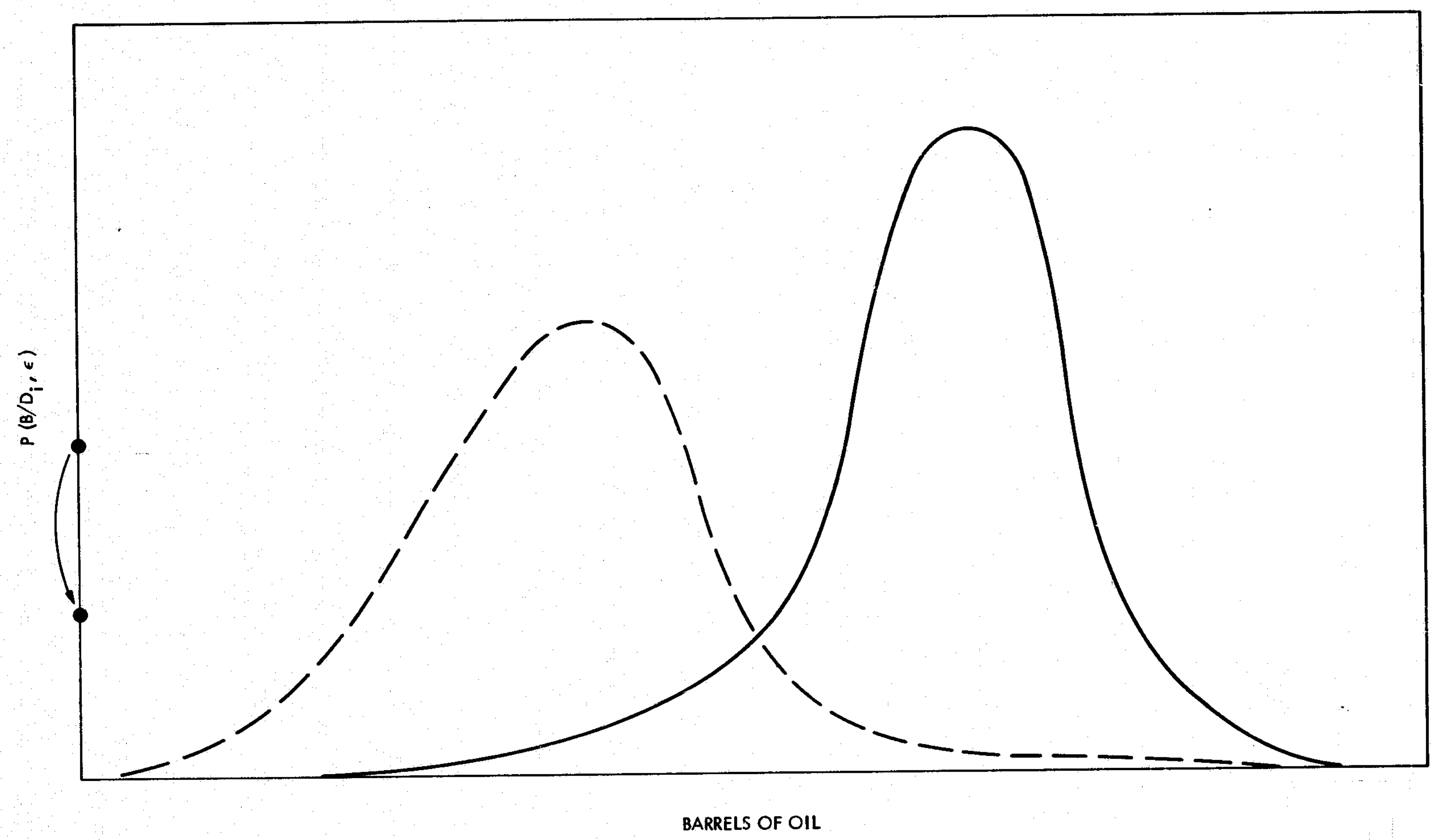


Fig. T-10. Posterior Probability Density on Field Size

Therefore, given the prior distribution $P(N, \underline{v} \mid \lambda, b, c)$ over the unknown state of nature $\tilde{N}$, $\tilde{v}$, the conditional distribution of the observation $\tilde{n}$, $\tilde{\alpha}$ given a search effort T is

$$P(n, \alpha \mid T) = \left\{ \left[\lambda A \left(1 - \left(\frac{c}{c+ T} \right)^{b} \right) \right]^{n} n! \right\} \exp \left[- \lambda A \left(1 - \left(\frac{c}{c+\gamma T} \right)^{b} \right) \right]$$

$$\left\{ \prod_{i=1}^{i=n} (1 - e^{-\gamma \alpha_i T}) f(\alpha_i \mid b, c) \left[1 - \left(\frac{c}{c+\gamma T} \right)^{b} \right] \right\}$$

where γ is the search efficiency parameter.

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APPENDIX U

METHOD OF ECONOMIC EVALUATION OF FASTER DRILLING TECHNIQUES

Several methods for improved drilling are presently being investigated. An important aspect is economic feasibility, and one element is the cost comparison between the conventional rock-bit drilling technique and the expected new system. The following discussion outlines a method of cost comparison:

It is assumed that a new drilling method will drill the same size hole as a conventional rig and that the down-hole logging, testing, and casing requirements will be the same. Using these assumptions, cost savings will result from increased drilling rates, provided bit and equipment life remains the same and operating costs are not increased excessively.

The footage cost for a given bit run equals

$$c = \frac{(T+L)\ C+B}{RL} \qquad \text{(Eq. 1)}$$

where

c = footage cost (\$/ft)

T = average trip time (hrs)

L = bit life (hrs)

C = rig cost (\$/hr)

B = bit cost (\$)

R = average drilling rate (ft/hr)

The ratio of the drilling rate R' with the new method to the conventional drilling rate R needed to produce a percent savings P in rotating cost is found from Eq. 1 to equal

$$\frac{R'}{R} = \frac{100}{(100-P)}\ \frac{L}{L'}\ \frac{(T' + L')C' + B'}{(T + L)C + B} \qquad \text{(Eq. 2)}$$

where the primes refer to the new method drilling.

Using Eq. 2, the effects of the various parameters can be evaluated. Examples (1973 costs) of these parameters are as follows:

1) $\frac{R'}{R} = 2$ and 3

2) Onshore drilling rig costs: 12,000 ft. rig: \$1500 per day (\$62.50/hr)

20,000 ft. rig: \$2000 per day (\$83.33/hr)

3) Offshore drilling costs: Platform 12,000 ft rig: \$6,000 per day (\$250 per hour)

Jack-up 16,000 ft rig: \$12,000 per day (\$500 per hour)

Floating 12,000 ft rig: \$16,000 per day (\$666.67 per hr)

4) Trip time = 6 hours (same both systems)

5) New bit cost = \$500 each

6) Conventional bit cost = \$300 each

7) New bit life = 15 hours (assumed)

8) Conventional bit life = 15 hours

9) Additional rig cost per hour \$125 (assumed)

Assuming an offshore platform costing \$250 per hour and additional costs for the new drilling method of \$125 per hour which increases drilling rate 3 times, the following percent savings is calculated:

$$3 = \frac{100}{100-P} \times \frac{15}{15} \quad \frac{(6 + 15)\ \$375 + 500}{(6 + 15)\ \ 250 + 300}$$

or P = 47% savings

APPENDIX V

INTERVIEWS CONCERNING BENEFITS EXPECTED FROM SUCCESSFUL DEVELOPMENT OF EACH CONCEPT

After the various concepts have been formulated and developed to the extent described in this report, interviews were held with a number of managers in the petroleum and petroleum service industries to help assess the benefits to be expected from each concept.

After an introduction, the interviewee was asked whether he was interested in each of the following topics:

1) Seismic-reflection systems.
2) Down-hole acoustic techniques.
3) Identification of geologic analogies.
4) Drilling methods.
5) Remote geochemical sensing.
6) Sea-floor imaging and mapping.

The interviewer then laid out on the table five cards bearing the following wordings:

1) Of enormous significance.
2) Of great help.
3) Of some help.
4) No help.
5) Counter-productive.

He gave the interviewee, one by one, a series of cards that covered the concepts falling under the topics selected as of interest. Each card contained a brief description of what one or more concepts was expected to accomplish. The interviewee was asked to assume that the concept had been successfully developed and to rate its significance by placing the concept card under the appropriate significance card.

After all concepts under the topics of interest had been rated, those rated as "enormous significance" or "great help" were gathered up by the interviewer. If very few or no concepts had been assigned to these ratings, the "some help" concept cards were also gathered. The interviewer handed these back to the interviewee, one by one, and asked the questions listed below, corresponding to each concept card. Another interviewer recorded the answers on a prepared form.

This interview methodology was devised by The Futures Group.

SEISMIC

SWEPT-FREQUENCY SEISMIC SOURCES (Concepts 2 and 3)

1) Would these techniques add to an existing technique or would they replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.
   d) Should reduce time for exploration.
   e) Should reduce cost of exploration.
   f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) In terrain inaccessible to Vibroseis, what is the value of a portable swept-frequency source?

5) What improvement in exploration success would you expect with a swept-frequency source providing twice the depth penetration of Vibroseis at frequencies below 80 Hz?

6) What improvement in exploration success would you expect from a swept-frequency source permitting resolution twice as good as with Vibroseis?

7) Under what conditions could you see these techniques being used?

8) If these techniques were developed, what would you consider an acceptable price range for this service?

9) If present trends continue, how many times per year can you envision using these techniques?

10) Do you know of any technique like this that's available now? If so, who has it?

11) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

SEISMIC

OSCILLATION-FREE BUBBLE SEISMIC SOURCE (Concept 4)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.
   d) Should reduce time for exploration.
   e) Should reduce cost of exploration.
   f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Would this technique reduce data-processing costs?

5) What kinds of structures are masked by air-bubble oscillation?

6) What increase in success might result from elimination of this masking?

7) Under what conditions could you see this technique being used?

8) If this technique was developed, what would you consider an acceptable price range?

9) If present trends continue, how many times per year can you envision using this technique?

10) Do you know of any technique like this that's available now? If so, who has it?

11) Do you know if any technique like this that has been tried and abandoned? If so, by whom?

SEISMIC

OSCILLATION-FREE IMPLOSION SEISMIC SOURCE (Concept 5)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.

d) Should reduce time for exploration.
e) Should reduce cost of exploration.
f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Would this technique be useful in deep-water operations?

5) Is it useful to have the source deep for deep-water operations?

6) Would this technique be useful for a bore-hole seismic source?

7) Is there any need for a bore-hole source?

8) Under what conditions could you see this technique being used? (a) Marine? (b) Borehole?

9) If this technique was developed, what would you consider an acceptable price range? (a) For marine use? (b) For borehole use?

10) If present trends continue, how many times per year can you envision using this technique?

11) Do you know of any technique like this that's available now? If so, who has it?

12) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

<u>SEISMIC</u>

AERIAL SEISMIC SURVEY (Concept 6)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

a) Should increase discoveries.
b) Should reduce the number of dry holes.
c) Should decrease exploration uncertainties.
d) Should reduce time for exploration.
e) Should reduce cost of exploration.
f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Where could you see using this method?

5) Why would you use this method?

6) Under what conditions could you see this technique being used?

7) <u>Oil Co</u>.: If this technique was developed, what would you consider an acceptable price range before you'd use it?

<u>Service Co</u>.: If this technique was developed, at what price range do you think you could find customers for it?

8) If present trends continue, how many times per year can you envision using this technique?

9) Do you know of any technique like this that's available now? If so, who has it?

10) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

<u>SEISMIC</u>

TELEMETRY OF SEISMIC DATA FROM SHIP TO COMPUTING CENTER (Concept 7)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.
   d) Should reduce time for exploration.
   e) Should reduce cost of exploration.
   f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) What is the value of reducing the time to get data back to the computing center?

5) What is the value of processing data in a computing center before the survey ship has left the area?

6) If this technique was used, would it eliminate recording and preserving all the data aboard ship?

7) Is it desirable to eliminate recording and preserving all the data aboard ship?

8) Under what conditions could you see this technique being used?

9) Oil Co.: If this technique was developed, what would you consider an acceptable price range before you'd use it?

Service Co.: If this technique was developed, at what price range do think you could find customers for it?

10) If present trends continue, how many times per year can you envision using this technique?

11) Do you know of any technique like this that's available now? If so, who has it?

12) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

SEISMIC

LOW-COST SEISMIC DATA PROCESSING

(High-Density Tape Recording)-(Concept 8A)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increased discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.
   d) Should reduce time for exploration.
   e) Should reduce cost of exploration.
   f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to other companies?

4) Is a higher recording density valuable?

5) Under what conditions could you see this method being used?

6) What would you consider an acceptable price range for high density tape recording before you would use it?

7) Oil Co.: How many reels of conventional tape that you use per year can you envision being replaced by high-density tape?

Service Co.: How many reels of conventional tape that you use per year can you envision being replaced by high-density tape?

8) Do you know of any technique like this that's available now? If so, who has it?

9) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

SEISMIC

LOW-COST SEISMIC DATA PROCESSING

(CCD Field Processing)-(Concept 8B)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.
   d) Should reduce time for exploration.
   e) Should reduce cost of exploration.
   f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to other companies?

4) Is 50% saving in data processing time important?

5) Is 50% saving in data processing cost important?

6) Under what conditions could you see this method being used?

7) What would you consider an acceptable price extra for reducing data processing time by 50%?

8) Oil Co.: (a) How many times per year can you envision paying the extra you mentioned to reduce data-processing time? (b) What would be the annual savings to you if the cost of data processing were cut 50%?

   Service Co.: (a) How many times per year can you envision your customers paying the extra you mentioned to reduce data-processing time? (b) What would be the annual savings to you if the cost of data processing were cut 50%?

9) Do you know of any technique like this that's available now? If so, who has it?

10) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

SEISMIC

LOW-COST SEISMIC DATA PROCESSING

(CCD Central Processing)-(Concept 8C)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

    a) Should increase discoveries.
    b) Should reduce the number of dry holes.
    c) Should decrease exploration uncertainties.
    d) Should reduce time for exploration.
    e) Should reduce cost of exploration.
    f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Is more extensive field processing valuable?

5) Under what conditions could you see this method being used?

6) What would you consider an acceptable price extra for rapid and extensive field data processing?

7) <u>Oil Co</u>.: How many miles of such field processing can you envision buying per year with the price extra you mentioned?

    <u>Service Co</u>.: How many times per year can you envision your customers paying the extra you mentioned for extensive field processing?

8) Do you know of any technique like this that's available now? If so, who has it?

9) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

SEISMIC

HIGH-RESOLUTION SEISMIC SYSTEM (Concept 9)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

    a) Should increase discoveries.

b) Should reduce the number of dry holes.
c) Should decrease exploration uncertainties.
d) Should reduce time for exploration.
e) Should reduce cost of exploration.
f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Under what conditions could you see this technique being used?

5) <u>Oil Co.</u>: If this technique was developed, what do you consider an acceptable price range before you would use it? (a) For marine work? (b) For land work?

<u>Service Co.</u>: If this technique was developed, what price range do you think you could sell it for? (a) For marine work? (b) For land work?

6) If present trends continue, how many times per year can you envision using this technique? (a) For marine work? (b) For land work?

7) Do you know of any technique like this that's available now? If so, who has it?

8) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

SEISMIC

TIME DELAY SPECTROMETRY IN REFLECTION SEISMIC SURVEYS (Concept 10)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

a) Should increase discoveries.
b) Should reduce the number of dry holes.
c) Should decrease exploration uncertainties.
d) Should reduce time for exploration.
e) Should reduce cost of exploration.
f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Would higher resolution, obtained as outlined, be valuable?

5) Would information of the kind mentioned be valuable through indicating the physical characteristics of the beds?

6) Under what conditions could you see this technique being used?

7) Oil Co.: If this technique was developed, what would you consider an acceptable price range before you'd use it?

   Service Co.: If this technique was developed, at what price range do you think you could find customers for it?

8) If present trends continue, how many times per year can you envision using this technique?

9) Do you know of any technique like this that's available now? If so, who has it?

10) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

DOWNHOLE ACOUSTIC

DOWNHOLE SEISMIC TOMOGRAPHY (Concept 11)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce number of dry holes during exploration.
   c) Should reduce number of dry holes during development.
   d) Should decrease exploration uncertainties.
   e) Should decrease development uncertainties.
   f) Should reduce time for exploration.
   g) Should reduce time for development.
   h) Should reduce cost of exploration.
   i) Should reduce cost of development.
   j) Others.

3) Would this technique and its associated benefits be specific to your company, useful to all companies, or useful only to other companies?

4) Are there cases where surface seismic methods are useless because of the weathered layer or a poorly transmitting layer?

5) If so, would the proposed method help locate places to drill?

6) Would the availability of a down-hole technique be of significant use for field step-out and development?

7) Under what conditions could you see this technique being used?

8) Oil Co.: If the technique were developed, what would you consider an acceptable price range for this service before you'd use it? (When you say so many $ per hole, what depth of hole have you in mind?)

Service Co.: If the technique were developed at what price range do you think you would find customers for it? (When you say so many $ per hole, what depth of hole have you in mind?)

9) If present trends continue, how many times per year can you envision using this technique in exploration? In development?

10) Do you know of any technique like this that's available now? If so, who has it?

11) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

GEOLOGIC EVALUATION

IMPROVED COMPUTER AID IN RECOGNIZING GEOLOGIC ANALOGIES (Concept 13)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

a) Should increase discoveries.
b) Should reduce the number of dry holes.
c) Should decrease exploration uncertainties.
d) Should reduce time for exploration.
e) Should reduce cost of exploration.
f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to other companies?

4) Oil Co.: (a) If a system with the capability described was developed, would it be favorably received by your management and geologists? (b) If not, do you think they might eventually be "sold" on it?

Service Co.: If a system with the capability described was developed, do you think it could be sold to your customers?

5) Under what conditions could you see this technique being used?

6) Oil Co.: If this technique was developed, what would you consider an acceptable price range before you'd use it?

Service Co.: If this technique was developed, at what price range do think you could find customers for it?

7) If present trends continue, how many times per year can you envision using this technique?

8) Do you know of any technique like this that's available now? If so, who has it?

9) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

DRILLING

AUTOMATED DRILLING RIG (Concept 14)

1) Would this technique add to an existing technique or would it replace one?

2) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

3) Would this technique be applicable primarily to

   a) On-shore drilling?
   b) Off-shore drilling?
   c) Both?

4) Would your company have any interest in the technique described?

5) Would operating a demonstration rig be of value in convincing you whether the concept is economically and technically feasible?

6) Do you think this technique would improve your competitive position?

7) Under what conditions could you see this technique being used?

8) <u>Drilling Co. only</u>

   If this technique was developed, what would you consider an acceptable price range per rig before you would use it?

9) <u>Drilling Co. only</u>

   a) If present trends continue, how many of your rigs could you envision using this technique?

   b) What percent of the use would be for exploratory drilling and what percent for development drilling?

10) Do you know of any technique like this that's available now? If so, who has it?

11) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

DRILLING

HIGH-PRESSURE, RESONANT VIBRATION, OR COMBUSTION-FRACTURE DRILLING OR IMPROVED DOWN-HOLE DRILL MOTOR (Concepts 15, 16, 17, 18)

1) Would these techniques add to an existing technique or would they replace one?

2) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

3) Would your company be willing to spend additional money to equip a drilling rig for increased penetration rate?

4) Are improved drilling methods needed for hole deeper than 20,000 feet?

5) Would your company have any interest in the four techniques mentioned? In which of the four?

6) Would operating a demonstration rig be of value in convincing you whether a concept is economically or technically feasible?

7) Under what conditions could you see these techniques being used?

8) <u>Drilling Co. only</u>

   a) If one of these techniques was developed, how much would you consider an acceptable added cost of a rig before you would use it?
   b) What would be an acceptable added operating cost before you would use it?

9) <u>Drilling Co. only</u>

   a) If present trends continue, how many of your rigs could you envision using one of these drilling techniques? Which technique? How about the other drilling techniques mentioned?
   b) What percent of the use would be for exploratory drilling, and what percent for development drilling?

10) Do you know of any technique like this that's available now? If so, who has it?

11) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

REMOTE GEOCHEMICAL SENSING

REMOTE GEOCHEMICAL SENSING (Concept 19)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.
   d) Should reduce time for exploration.
   e) Should reduce cost of exploration.
   f) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to _other_ companies?

4) Under what conditions could you see this technique being used?

5) _Oil Co._: If this technique was developed, what would you consider an acceptable price range before you'd use it?

   Service Co.: If this technique was developed, at what price range do you think you could find customers for it?

6) If present trends continue, how many times per year can you envision using this technique?

7) Do you know of any technique like this that's available now: If so, who has it?

8) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

SEA FLOOR

ACOUSTIC IMAGING OF LARGE AREAS OF SEA FLOOR (Concept 20)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

   a) Should increase discoveries.
   b) Should reduce the number of dry holes.
   c) Should decrease exploration uncertainties.
   d) Should reduce time for exploration.
   e) Should reduce cost of exploration.

f) Should help in assessing underwater hazards to exploration.
g) Should help in the design of development and production equipment to suit the local sea floor.
h) Should help in selecting pipe laying routes.
i) Should help in assessing underwater hazards to development and production equipment.
j) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Would high-quality imagery of large areas of the sea floor, at resolution comparable to Landsat imagery, be valuable?

5) Would images at resolution <u>better</u> than Landsat be more valuable?

6) Under what conditions could you see this technique being used?

7) <u>Oil Co</u>.: If this technique was developed, what would you consider an acceptable price range before you'd use it?

<u>Service Co</u>.: If this technique was developed, at what price range do you think you could find customers for it?

8) If present trends continue, how many square miles could you envision imaging by this technique, per year?

9) Do you know of any technique like this that's available now? If so, who has it?

10) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

<u>SEA FLOOR</u>

DETAILED BATHYMETRIC CHARTING (Concept 21)

1) Would this technique add to an existing technique or would it replace one?

2) For which of these reasons do you think this concept is significant?

a) Should increase discoveries.
b) Should reduce the number of dry holes.
c) Should decrease exploration uncertainties.
d) Should reduce time for exploration.
e) Should reduce cost of exploration.
f) Should help in assessing underwater hazards to exploration.
g) Should help in the design of development and production equipment to suit the local sea floor.
h) Should help in selecting pipe laying routes.

i) Should help in assessing underwater hazards to development and production equipment.
j) Others.

3) Would these techniques and their benefits be specific to your company, useful to all companies, or useful only to <u>other</u> companies?

4) Would closer data spacing than that presently available on bathymetric charts be valuable? Why?

5) What data spacing is desirable?

6) Under what conditions could you see this technique being used?

7) <u>Oil Co</u>.: If this technique were developed, what would you consider an acceptable price range before you'd use it?

<u>Service Co</u>.: If this technique was developed, at what price range do you think you could find customers for it?

8) If present trends continue, how many square miles of tracking could you envision charting by this technique, per year?

9) Do you know of any technique like this that's available now? If so, who has it?

10) Do you know of any technique like this that has been tried and abandoned? If so, by whom?

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