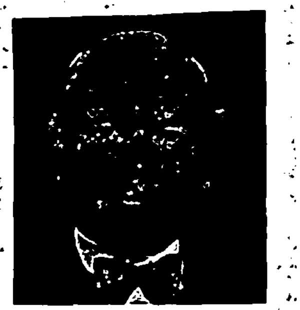
GL01367

Fueling the 80's

A Special Engineering Report on Meeting U.S. Energy Demands

Contents

Anderson: Energy Situation is Positive Challenge to U.S.



To the Readers of
Mining Engineering and
Journal of Petroleum Technology

Dear Readers:

The United States is entering the 1980's facing the most severe technological and organizational challenge in our history: Can we produce enough energy in the years ahead to assure that our society will continue to grow and prosper?

The situation is not encouraging. Oil, the dominant fuel of the postwar era, is fading. The OPEC countries, source of the bulk of our imports, are orchestrating production cutbacks to support devastating price rises. They thereby offer up a preview of the day OPEC's limited production will be a matter of physical necessity rather than political choice. If I were to guess, I would say that the U.S. will not be able to get much more oil from OPEC countries in the 1980's than we are now. They seem that close to their production limit.

This fact of import limitation inevitably means that our energy security in the 1980's and beyond depends largely upon resources at home. Fortunately, the list is long: conventional oil and gas, practical methods of accelerating production from older oil fields, and a strong array of alternatives including coal (U.S. reserves are the world's largest), shale oil, nuclear, geothermal, solar, and more.

Obviously, continued conventional energy development in the 1980's and 1990's is crucial if we are to have time to put renewable resource technologies in place. We're making headway in this quarter. New seismic technology based on computer modeling, for example, allows explorers to "see" deeper and in greater detail to uncover oil and gas in previously unsuspected areas such as the Overthrust Belt geological formation in the mountain states. And various enhanced recovery techniques show great promise of increased production from established fields. Today, the world recovery rate of proven crude oil reserves averages about 30%. Each percent increase will enlarge reserves by one-thirtieth, a very substantial fraction.

Coal and nuclear are the "bridging fuels" to carry us through the decline of oil and gas to the era of the renewables. Both face major hurdles. Mining and processing coal involve considerable environmental problems. Acceptable technological safeguards are needed to deal with phenomena such as the "greenhouse" effect and acid rainfall. As for nuclear, we think that by 1990 U.S. production could be the oil equivalent of 4 million barrels a day – four times the present level. With Three Mile Island a vivid memory, however, nuclear operating and waste-disposal safety must be assured.

Our assumption is that the future will belong to solar as our chief source of renewable energy. But probably more important in the short run is "conservation energy" – the cheapest and most immediate alternative. By President Carter's figures, an investment of approximately $35,000 will be necessary to make a daily barrel of synthetic fuel, but only $4,000 to save a barrel. The National Academy of Science estimates that "in the year 2010, very similar conditions of habitat, transport, and other amenities could be provided in the United States *using twice the energy consumed today or 20 percent less than is used today.*" Our choice seems obvious.

When all is said and done, I find no reason to side either with the neo-Malthusians who see a rigidly limited natural resource pie, especially energy; or with misguided optimists who cling to yesterday's innocent faith in "onward and upward forever."

We must seek the middle road, recognizing that there will be limits and obstacles but none that cannot be overcome by a liberal application of the most critical resource of all – human inventiveness. The U.S. always has been an ingenious country, a nation at its best under duress and pressure. In the 1980's we are going to have a splendid opportunity to demonstrate whether we still have that capacity. I think we do.

Sincerely,

R.O. Anderson
Chairman and Chief Executive Officer
Atlantic Richfield Co.

Robert O. Anderson is chairman of the board and chief executive officer of Atlantic Richfield Co. He has worked in the petroleum industry since 1939, when he joined a subsidiary of Pure Oil Co. Anderson spent 22 years in petroleum refining, in which time he owned Wilshire Oil Co. of California and served as president of Hondo Oil and Gas Co. He served from 1961 to 1964 as chairman of the board of the Dallas Federal Reserve Bank, and was named to his present position in 1965. He has served on the National Petroleum Council since 1951. He holds a BA degree from the U. of Chicago.

Energy Resources for Tomorrow

Milton F. Searl*, Electric Power Research Institute

Introduction

The urgency of further development of our domestic energy resources becomes more apparent every day. The production capability of existing facilities, taken in the aggregate, declines perhaps 10% per year; imported energy is expensive if available at all; conservation helps reduce demand but eventually will reach a point of diminishing return; new energy sources are promising but past experience, as with nuclear power, teaches us lead times are long and success is not assured.

To approach the energy future rationally, it is essential to have some idea of the size of the nation's remaining energy resources, their characteristics, and the degree of uncertainty involved in their estimates. Resources are, of course, only one end of a long chain leading to energy supply to the ultimate consumer. They are an essential element, however, and the only one not under society's control. Given that the resources and a national will to produce the energy exist, it is possible to convert the resources to supply in, generally, an environmentally reasonable manner. However, the process of developing supply takes time. Government must permit access to the resource, and remunerative prices and further evolution of technlogy are required. This paper does not deal with these essentials, but they must not be forgotten. This discussion is limited to coal, oil, natural gas and gas liquids, uranium, and oil shale. Other energy sources are discussed elsewhere in this issue.

*Views are those of the author and not necessarily those of EPRI.

Crude Oil

Conventional crude oil resources are of greatest concern today, given our dependence on imported oil and its rapidly rising price. Estimates of oil originally in place (OOIP) range from 619 billion bbl to 1,094 billion bbl, differing by almost a factor of two (Table 1). This is surprising because the U.S. is a mature petroleum province with over 120 billion bbl produced and over 400 billion bbl OOIP discovered. Differences in the estimates involve differences in the experience of the various estimators, the interpretation of present geologic information and historical statistics, the methodology, and probably the extent (i.e., water depths) for which offshore resources are included.

The range shown for the estimate of a given estimator appears to be primarily due to geologic uncertainty. This uncertainty can be measured by taking the ratio of the low and of the high estimate to the expected estimate for that information source. The low estimates range from 0.85 to 0.87 of their respective values. The high estimates range from 1.18 to 1.27 of the expected values. In all cases the high estimate is further from the expected value than the low,

TABLE 1 – COMPARISON OF UNITED STATES CRUDE OIL RESOURCE ESTIMATES[1] (billion barrels)

Based on	Original Oil Resources In Place	Ultimate Cumulative Recovery at 30%	Ultimate Cumulative Recovery at 40%
National Petroleum Council (1973)	810	259	324
M. King Hubbert (1974)	666	213	266
USGS Circ. 725 (1975)	681-781-922	218-250-295	272-312-369
Mobil (1975)	647-756-959	207-242-307	259-302-384
National Academy of Sciences (1975)	809	259	324
Exxon (1976)[2]	744-878-1,094	238-281-350	299-351-438
Parent and Linden (Institute of Gas Technology, 1977)	828	265	331
Shell (1978)	619-713-838	198-228-268	248-285-335

1. Adapted from earlier work by Jeremy Platt, Energy Supply Program geologist, Electric Power Research Institute. Most sources do not give all of the figures shown for them in Tables 1 and 2 and assumptions have been necessary to derive a full set of figures. In cases where ultimate recovery was given instead of oil in place, a 32% recovery factor was used to derive original oil in place.

2. Exxon is said to have lowered their estimate recently.

TABLE 2 – ESTIMATES OF REMAINING RECOVERABLE CRUDE OIL RESOURCES[1]
Discovered and to be Discovered (billion barrels-December 31, 1978)

Based	Remaining Recoverable Resources At 32% Recovery	Remaining Recoverable Resources At 40% Recovery	Proved Reserves Plus Estimated Revisions and Extensions	Undiscovered Recoverable Resources At 32% Recovery	Undiscovered Recoverable Resources At 40% Recovery
National Petroleum Council (1973)	138	203	50	88	153
M. King Hubbert (1974)	92	145	50	42	95
USGS Circ. 725 (1975)	97-129-174	151-191-248	50	47- 79-124	101-141-198
Mobil (1975)	86-121-186	138-181-263	50	36- 71-136	88-131-213
National Academy of Sciences (1975)	138	203	50	88	153
Exxon (1976)[2]	117-160-229	177-230-317	50	67-110-179	127-180-267
Parent and Linden (Institute of Gas Technology, 1977)	144	210	50	94	160
Shell (1978)	77-107-147	127-164-214	50	27- 57- 97	77-114-164

1. Adapted from earlier work by Jeremy Platt, Energy Supply Program geologist, Electric Power Research Institute. Most sources do not give all of the figures shown for them in Tables 1 and 2 and assumptions have been necessary to derive a full set of figures. In cases where ultimate recovery was given instead of oil in place, a 32% recovery factor was used to derive original oil in place.

2. Exxon is said to have lowered their estimate recently.

indicating greater uncertainty on the upside than on the downside.

Although it appears premature to write off the Atlantic Coast as a result of failures to date in the Baltimore Canyon, assuming that there is no oil off the Atlantic Coast would require that the USGS low estimate of OOIP be reduced by about 6 billion bbl and the high estimate by 18 billion bbl. Estimated recoverable resources would be reduced by a third of these amounts. Presumably, similar adjustments would be required in the other estimates.

A critical parameter in estimating the amount of oil yet to be produced is the percentage of OOIP that can be recovered. Experience indicates an average of about 32% recovery using primary and secondary recovery methods, although individual fields may have over 90% or less than 10% recovery. Actual and prospective higher prices for oil have led to increased interest in new methods of enhanced oil recovery (EOR). The amount that these EOR methods will increase recovery is highly uncertain. Some observers see an increase in average recovery of all OOIP of only a few percent. Others see as much as a 7% or 8% increase. For purposes of illustration, Table 1 shows ultimate cumulative recovery at two different levels, 32% and 40%. If we are very clever, recovery may even exceed 40%.

Table 2 shows what these ultimate recoverable figures mean in terms of remaining recoverable oil resources and opportunities for discovery. At the minimum we have nearly 80 billion bbl of oil left to produce and nearly 30 billion bbl left to discover. It is assumed that development drilling of known fields plus upward revision of estimates for older fields will eventually add 22 billion bbl to proved reserves of 28 billion bbl for a total of 50 billion bbl not requiring major discovery effort. This number is not crucial. A lower estimate of this quantity will simply add to the amount yet to be discovered. A reasonable expectation, allowing for some increase in recovery factors, would be 120 billion bbl left to be produced, of which about 70 billion bbl remains to be discovered. Nothing precludes a fair possibility of even more. Overall, the crude oil resource base is adequate to support large efforts to increase recovery factors as well as to support extensive exploration and development campaigns.

Remaining recoverable oil of 120 billion bbl is equal to 40 years' supply at current rates of production, although production will in fact be strung out over a much longer period. From the discovery, development, and production standpoint, I believe there is a good possibility that production levels can be increased for several decades. A production increase is favored by prices for crude oil which, in constant dollars, are likely to be several times 1973 prices even after new federal taxes. An increase also is favored by increasing interest in EOR and by favorable prospects in areas such as the Overthrust Belt in Wyoming, Idaho, Montana, and Utah. The number of oil well completions is nearly twice the 1973 level and seismic exploration is at its fastest pace in 20 years. Several industry executives have indicated that over a million barrels per day could be added to production in the mid-1980s with price decontrol, according to several sources (C.T. Sawyer, American Petroleum Institute in the *Oil Daily*, May 18, 1979, p. 5; Jack Allen, president of Independent Petroleum Association of America in the *Oil and Gas Journal*, February 26, 1979, p. 41; and John Swearingen, chairman of the board of Standard Oil Co. of Indiana at stockholder's meeting). The Energy Information Administration of the U.S. Dept. of Energy in its recent report to Congress (*DOE/EIA-1073/3*, p. 64, released in mid-1979) shows five alternate projections of domestic oil supply for 1985. They range from essentially the 1978 level to 20% higher. A negative factor is that much favorable acreage is not being leased by the federal government.

There has been disappointment in recent years about the response of both crude oil and natural gas production and reserve levels to higher prices. Disappointment may be premature. In constant dollars crude oil price increases have been rather moderate (1978 constant dollar price 63% above 1973) and price expectations were uncertain under federal regulation. Moreover, as oil and gas drilling expanded rapidly, abnormal pressure was placed on drilling and equipment costs. The first response to a price increase is increased drilling of known but previously uneconomic resources, and in some cases infill drilling. These are appropriate short-term responses but are likely to be less productive than development that results from carefully planned, expanding exploration programs over a period of years.

Natural Gas

Natural gas resources are of only slightly less concern to the nation than oil resources. While the nation does not depend upon imports for much of its natural gas supply, a falling output of natural gas would exacerbate oil and electricity supply problems, whereas a rising output of natural gas could help reduce the pressure on oil imports and possibly help offset potential electric power shortages.

Table 3 shows estimates of natural gas resources. Because 80-85% of gas in place is normally recovered, there is not a large potential role for enhanced recovery. Estimates are cast in terms of ultimate recoverable gas rather than gas originally in place.

The low estimate of remaining recoverable gas of 635 trillion cubic ft (Tcf) and the high of 1,500 Tcf are both Exxon's figures. Exxon's expected value is 46% greater than its low figure. Its high figure is 61% greater than its expected value. As with the oil estimates, this can be interpreted as greater uncertainty on the upside than on the downside. The USGS range is nearly symmetrical about the expected value.

There is considerable difference in the estimates of the amount of gas remaining to be discovered. This is partially due to differences in the amount inferred to exist beyond proved reserves but not requiring discovery. The Amoco to-be-discovered figure is of particular interest here because Amoco has indicated that it believes the amount remaining to be discovered would approach 700 Tcf as opposed to the earlier USGS figure of 484 Tcf as a result of recent discovery experience.

If commercial gas is not found off the Atlantic Coast, about 10 Tcf should be deducted from the expected USGS remaining recoverable figure of 923 Tcf and, presumably, a similar amount from the other estimates.

A reasonable expected value for remaining recoverable gas resources would be in the 900 to 1,000 Tcf range. This is 45 to 50 times current annual production.

From a resource standpoint there is substantial opportunity to expand production above current levels. Gas well drilling has been increasing at a rapid pace and there have been a number of promising discoveries.

There are several differences between the outlook for oil and that for natural gas. The probability of finding gas instead of oil increases with depth. Both terrestial and marine organic matter can serve as a source for gas, thus enlarging the prospective terrain for gas. Also, only a little over one-third of the postulated ultimate recoverable gas resources have already been produced, compared with one-half of the oil. On the other hand, new discoveries play a larger role in expanded gas output than in expanded oil output, which is more dependent on increasing recovery factors in known and new reservoirs.

Hydrocarbons that are somewhat heavier than methane but lighter than crude oil are recovered during the production of natural gas. These are referred to as natural gas liquids (NGL) and are an important element of our liquid hydrocarbon supply. They currently constitute 16% of our domestic liquid hydrocarbon production on a volume basis and 10% on a Btu basis. Cumulative production of NGL's through 1978 was 18 billion bbl. Measured reserves are 6 billion bbl and

TABLE 3 — NATURAL GAS RESOURCE ESTIMATES — CONVENTIONAL SOURCES[1]
(trillion cubic feet)

	Moody (1974)[a]	National Academy of Sciences (1974)	USGS(1974)[b]			Exxon (1974)			AMOCO (1977) (see note c)	Potential Gas Committee (1978)
			Low	Expected	High	Low	Base Expected	High		
Past production	480	480	–	480	–	–	480	–	538	558
Reserves	237	237	–	237	–	–	237	–	209	200
Inferred	65	119	–	202	–	56	111	321	199	199[d]
Subtotal	302	356	–	439	–	293	348	558	408	399
To be discovered	485	530	322	484	655	342	582	942	700	820
Remaining recoverable	787	886	761	923	1094	635	930	1500	1108	1219
Ultimate recoverable	1267	1366	1238	1403	1571	1112	1410	1977	1646	1777

a. Essentially the same as Mobil Oil (Moody and Geiger) 1973.
b. Figures are based on "...a continuation of price-cost relationships and technological trends generally prevailing in the recent years prior to 1974. Price-cost *relationships since 1974 were not taken into account because of the yet undetermined effect they may have on resource estimates.*" U.S. *Geological Survey* Circ. 725, p.1.
c. In SPAN, a company magazine, undiscovered resources as estimated by the USGS are discussed. Regarding the USGS gas figure of about 500 trillion cubic feet it is said "Recently improved success ratios for natural gas completions and prospective higher prices could increase undiscovered reserves toward the 700 trillion cubic foot range." (1978 Volume 2) All other numbers in this column are taken from other sources.
d. *Potential Gas Committee "probable resources."*

Note: Estimates generally assume that, on the average, 80-85% of the gas in a field is recoverable. These data exclude most gas from degasification of coal beds, Devonian shales, other tight (low-permeability) formations, geopressure zones, and gas hydrates (frozen methane). Small amounts from some of these sources may be included. The estimates also differ somewhat as to offshore depths included.

1. Adapted from earlier work by Jeremy Platt, Energy Supply Program geologist, Electric Power Research Institute.

TABLE 4 – DOMESTIC COAL RESOURCES[1] (Billions of tons at 100% recovery)

Less than 3,000 ft deep	
Demonstrated reserve base	438[2]
Additional identified coal	1,292
Total identified resources	1,730
Resources hypothesized in unexplored and unmapped areas	1,850
Identified and hypothesized above 3,000 ft	3,580
Between 3,000 ft and 6,000 ft deep	
Resources hypothesized in deeper structural basins	388
Total identified and hypothesized	3,968

1. The immediate source is the *1979 Keystone Coal Industry Manual*, pp. 693 and 694. Keystone's source is the USGS and the USBM. The "demonstrated reserve base" figure is as of 1/1/76 and the "additional identified coal" is as of 1/1/74. The hypothesized resources are composed of pre-1976 estimates from various sources, generally associated with state geologic surveys.
2. Strong objections have been voiced about the use of high recovery factors for the "demonstrated reserve base" by Richard Schmidt. Schmidt contends that recovery factors of "product fuel" may be close to 25%. See "Coal: Keystone of Energy Fuels, Electric Power Research Institute Journal, August 1977, page 6 ff.

undiscovered resources are estimated at from 10 to 20 billion bbl.

Coal

It is well known that the nation's coal resources are enormous (Table 4). However, coal is not a single chemical compound any more than petroleum is a single compound. Many thousands of different compounds have been identified in both. The petroleum refiner has learned to deal with the differences in crudes, an ability which is enhanced by the liquid nature of crude oil. Similarly, users of coal, e.g., steel mills and electric utilities, have learned to select coals on the basis of certain aggregate characteristics, such as Btu, moisture and ash content, and slagging characteristics. More recently, sulfur content has become important for environmental reasons.

In view of the need to match coal characteristics with specific consumption technology, aggregate resource estimates are of limited utility. They do tell us, with a certain degree of probability, that our coal resources are immense. For specific applications, however, much more detailed information is necessary and may be obtained only through detailed field work. Even information on sulfur content is frequently unreliable. There is little doubt that conventional electric power plants can be adapted to coal characteristics, whatever they are. However, as newer coal-using technologies emerge, coal characteristics become more crucial. For example, the efficiency and performance of coal liquefaction and gasification process (and catalysts) can be optimized for specific coals. In the absence of better knowledge about the specifics of coal resources, e.g., heavy metal content, it is necessary to develop technology that is less than optimal for specific coals but which can handle a wider range of coals.

While the resource base of coal is clearly adequate, there is an increased need for detailed information about the characteristics and mining conditions of the nation's coal resources. The very diversity of coal makes analysis of the path of future production complex and uncertain. And the new federal coal leasing program relies upon detailed forecasting of coal supply and demand in order to develop leasing schedules for federal coal. Recent work shows that much of the existing data on coal resources are incomplete for this kind of assessment. To some degree however, the optimism shown in USBM's use of a standard 50% recovery factor in underground mining may be offset by the discovery of further delineation of economic coal seams in areas that have been largely overlooked to date.

Transportation is an important component of delivered coal costs. Transportation costs frequently exceed the mine-mouth cost of the coal. This makes location relative to markets much more important in the case of coal than for oil and gas, except Alaskan oil and gas. Table 5 shows the location of the nation's larger coal resources along with the rank of the coal. About 20 billion st of antracite, almost all in Pennsylvania, are not shown.

Coal production is expected to be around 1 billion st in 1985 and perhaps 2 billion st in the year 2000. The volume of our coal resources, even if recovery factors are below 50%, is so large that, from the resource standpoint, coal certainly provides a viable resource base to meet our energy needs for at least several centuries. The widespread distribution of coal resources will tend to spread both the benefits and problems of coal production around the nation. Moreover, from the depletion standpoint there is no need for more than a very slow increase in coal costs, in constant dollars, at the mine. Indeed, productivity increases could lead to stable or declining real costs (see *Supply 77, Electric Power Research Institute Report EA-634-SR*, Section 3 and particularly pp. 3-5 on prices, 3-23 on productivity, and 3-27 on resource depletion).

On the negative side, the preferred energy forms of the economy are fluid and electric. Although coal can be converted to fluid fuels, the processes are expensive. It is likely to be at least a decade before large volume commercial production (e.g., 1 million bbl oil equivalent per day) is achieved, unless there is an all-out government program to produce fluid fuels from coal. The environmental effects of synfuel production from coal are still uncertain and their resolution may add substantially to costs. Coal will be called upon increasingly as a fuel for electric power production. However, costs of power from coal production must rise as environmental controls become more restrictive. And finally, there is the possibility that, ultimately, fossil fuel consumption will have to be restricted because of the accumulation of carbon dioxide in the atmosphere.

TABLE 5 – IDENTIFIED COAL RESOURCES BY AREA AND RANK (billions of tons at 100% recovery)

Area	Demonstrated Reserve Base: Bituminous	Demonstrated Reserve Base: Subbituminous	Demonstrated Reserve Base: Lignite	Additional Identified: Bituminous	Additional Identified: Subbituminous	Additional Identified: Lignite	Total Identified
Alaska	1	5	–	18	106	–	130
Colorado	9	4	3	100	13	–	129
Illinois	68	–	–	78	–	–	146
Indiana	10	–	–	22	–	–	32
Kentucky	26	–	–	38	–	–	64
Montana	1	103	16	1	74	97	292
New Mexico	2	3	–	9	48	–	62
North Dakota	–	–	10	–	–	340	350
Ohio	19	–	–	22	–	–	41
Pennsylvania	24	–	–	40	–	–	64
Texas	–	–	3	6	–	7	16
Utah	7	–	–	16	–	–	23
West Virginia	39	–	–	61	–	–	100
Wyoming	4	51	–	9	72	–	136
	210	166	32	420	313	444	1,585
Other states	19	2	2	98	5	0	126
Total	229	168	34	518	318	444	1,711

Source: The immediate source is the *1979 Keystone Coal Industry Manual*, pp. 693 and 694.

Shale Oil

An as yet unexploited resource of major dimensions is oil shale. In the early 1920s and the late 1940s oil companies were seriously considering turning to oil shale as a source of oil. However, in both cases expanding supplies of conventional oil made the use of shale uneconomic. Once again oil shale is on the verge of becoming commercial. Uncertainty about government policy, oil prices, and environmental impacts are delaying the actual start of production, but as world oil prices continue to increase, shale oil looks ever more promising.

Table 6 shows estimated recoverable shale oil resources in the Green River formation of the Uinta and Piceance basins of Colorado and Utah. The most accessible and better defined deposits contain an estimated 74 billion bbl of recoverable oil, volumetrically equivalent to 25 times current domestic crude oil production. Estimated remaining recoverable volumes in lower grade shales are over 1 trillion bbl, four times all the crude oil the nation is likely to produce in its entire history (see Table 6 footnotes for definitions).

There are environmental problems associated with shale oil production. Some observers also believe that production will be limited to a few million barrels per day due to water shortages. This may have been true in the past when shale oil would have competed with inexpensive oil. However, at prospective world oil prices for shale oil, water costs of even a dollar per bbl of shale oil produced might be acceptable. At such costs water could be brought long distances by pipeline or deep, brackish water formations tapped. Oil from shale will require some upgrading to be equivalent to crude oil; however, the technology is well established. The potential of shale is such that much effort to overcome the environmental obstacles appears worthwhile. However, oil from shale will not be cheap. Its costs are closer to those of liquids from coal rather than those of conventional oil.

In addition to the shale in Colorado, Wyoming, and Utah, there are large shale deposits (Devonian and Chattanooga) in the east. The USGS has estimated "known resources" of Devonian oil shale in the east at 400 billion bbl and "probable extensions of known resources" at a further 2,600 billion bbl on the basis of Fischer assay results. Recent analyses by the Inst. of Gas Technology (IGT) indicate that these shales are much richer in oil than previously believed. The standard Fischer assay indicated yields of about 7 gal per ton. Yields in the range of 20 gal have been demonstrated using the IGT "hydroretorting process." At such yields the shale would be comparable in grade with the "estimated remaining recoverable" material in the Green River formation (Table 6). The economics of producing this shale may be improved if other materials are produced as by-products.

Uranium

U.S. Dept. of Energy (DOE) uranium reserve and resource estimates are presented in Table 7. All other aggregate U.S. uranium

TABLE 6 – SHALE OIL RESOURCES IN THE GREEN RIVER FORMATION[a]

	Proved and Currently Recoverable[b]	Estimated Remaining Recoverable[c]
Billions of bbl	74	1,026
Quadrillion Btu	429	5,951

a. Green River Formation in the Uintah and Piceance basins of Colorado and Utah.
b. Based on only the most accessible and the better defined oil-shale deposits in the Green River formation; these deposits are at least 30 feet thick and average 30 gal of oil/ton by Fischer assay as given in *U.S. Energy Outlook, A Report of the National Petroleum Council's Committee on U.S. Energy Outlook*, Washington, DC, December 1972; also assuming 60% recovery of shale in the minable seam and oil recovery corresponding to 96 vol% of Fischer assay.
c. Based on the total quantity of oil-shale resources in the Green River formation ranging down to 15 gal of oil/ton by Fischer assay as estimated in the reference listed in footnote b, assuming 60% recovery of shale in the minable seam and oil recovery corresponding to 96 vol% of Fischer assay.

TABLE 7 – UNITED STATES URANIUM RESOURCES[1] AS OF JANUARY 1, 1979

$/lb U_3O_8 Forward Cost Category[2]	Tons U_3O_8				
	Reserves	Potential Resources: Probable	Possible	Speculative	Total
$15	290,000	415,000	210,000	75,000	990,000
$15-30 Increment	400,000	590,000	465,000	225,000	1,680,000
$30	690,000	1,005,000	675,000	300,000	2,670,000
$30-50 Increment	230,000	500,000	495,000	250,000	1,475,000
$50	920,000	1,505,000	1,170,000	550,000	4,145,000

Source: Department of Energy, Grand Junction Office

1. Evaluated areas only. Out of the 620 quadrangles into which the U.S. is divided, the Department of Energy considers 272 as geologically favorable for uranium. Evaluation of the most promising 116 was scheduled to be completed at the end of fiscal 1980. It is unlikely that the as yet unevaluated areas will be nearly as rich in uranium as the evaluated areas. On the other hand they are unlikely to be barren.
2. A rule of thumb conversion of forward costs to full costs is to multiply forward costs by 1.7.

estimates are in one manner or another based on DOE statistics and consist of manipulating the DOE data in one manner or another. The DOE estimates have been questioned from time to time but are widely accepted. It is my belief that they are reasonable numbers in terms of what DOE is estimating. However, attention must be paid to the definitions.

The cost figures used by DOE are so-called "forward costs" and exclude important cost elements. A common rule of thumb is to multiply the forward costs by 1.7 to estimate full costs. As noted in the footnote to Table 7, the resource estimates are not for the entire U.S. but only for evaluated areas. Perhaps most important are the definitions of potential resources. The definitions, as discussed in *Uranium Data* (*Electric Power Research Institute Report EA-400*, June 1977) are as follows:

1. "Probable" potential resources are those estimated to occur in known productive uranium districts that are (a) in extensions of known deposits, or (b) in undiscovered deposits within known geologic trends or areas of mineralization.

2. "Possible" potential resources are those estimated to occur in undiscovered or partly defined deposits in formations or geologic settings productive* elsewhere within the same geologic province.

3. "Speculative" potential resources are those estimated to occur in undiscovered or partly defined deposits that are (a) in formations or geologic settings not previously productive within a productive geologic province, or (b) within a geologic province not previously productive.

The reliability of the estimates lessens as one moves from "probable" to "speculative" as a reflection of diminished geologic knowledge and data base.

These definitions were patterned after those used by the Potential Gas Committee. They classify the resource according to the amount of information on which the estimate is based. Because of the less precise information in each class of resource from reserve to speculative, the more likely the "true" figures for that category may be much smaller or much larger than estimated.

A more sophisticated manner of looking at reserves and resources is to consider that any specific figure comes from a probability distribution and to estimate that distribution. The USGS did this for crude oil and natural gas in *USGS Circular 725, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States* (1975). DOE has done this for uranium reserves (Fig. 1). The midpoint (50% probability) on this figure is the same as the total reserve figure of Table 7. DOE is preparing similar probability

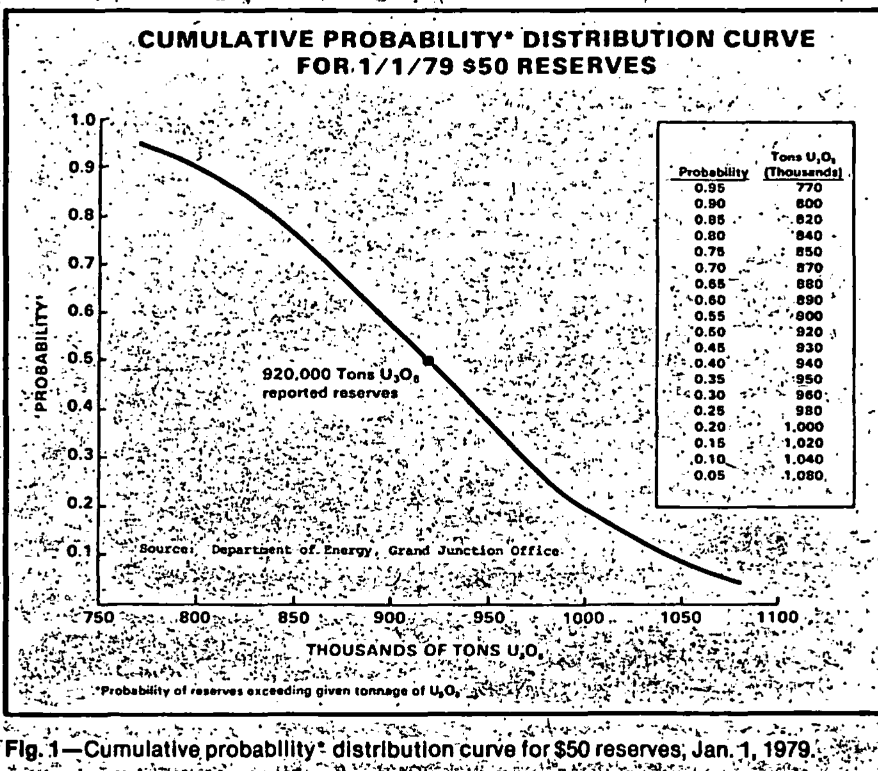


Fig. 1—Cumulative probability* distribution curve for $50 reserves, Jan. 1, 1979.

*"Productive" means that past production plus known reserves exceeds 10 tons U_3O_8.

distributions for its other resource classifications.

In addition to what might be described as conventional uranium resources discussed above, various other sources exist. DOE estimates that 120,000 st of U_3O_8 could be recovered as a by-product from other operations, principally phosphoric acid production, by the year 2000. Numerous low-grade uranium resources exist in the U.S. Most frequently mentioned are the uraniferous black shales that exist over large areas of the U.S. The Chattanooga shale in the east-central U.S. has received the most consideration. It is estimated to contain 5 million st of U_3O_8 at concentrations of 0.006% to 0.007% U_3O_8. Production costs, including environmental considerations permitting production, probably would exceed $200 per pound of U_3O_8. Current market prices are around $40 per pound.

Uranium requirements for the lifetime of a 1,000 megawatt reactor are about 5,000 st of U_3O_8 at current efficiency levels. Using this number with the table that is part of Fig. 1, there is a 95% probability that uranium reserves available at forward costs of up to $50 per pound of U_3O_8 can support 154,000 megawatts of capacity for their lifetime; a 50% probability that the reserves will support 184,000 megawatts; and a 5% probability that they will support 216,000 megawatts. To support additional nuclear light-water reactor generating capacity will require that known deposits in one of the potential classes be converted to reserves and that some of the undiscovered resources be discovered. If the breeder reactor becomes commercial, uranium resources will be adequate for centuries.

Conclusions

The nation does not lack energy resources worth developing in any of the categories considered here. Given favorable prices, access to federal lands, and environmental regulations that do not preclude production or utilization, the nation has the potential for becoming increasingly self-sufficient in conventional sources of energy.

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A Review of Alternative Energy Technologies

T.E. Walsh, Bechtel National Inc.

Introduction

I will address two important alternative energy resources, solar and geothermal, with emphasis on their potential application in electric power generation. As a result of this presentation, I hope to leave you with a realistic view of the principal technology options that are being developed or that are available.

Solar

Types of Collection

In terrestrial solar applications, the biggest challenge is to find ways of collecting the sun's relatively low intensity energy so it can be converted economically to useful thermal or electric energy.

Fig. 1 shows that there are both natural and technological ways of collecting solar energy. In nature we find that solar energy aids in the production of biological growth, rainfall, and wind, all of which can, in one form or another, be put to use in the production of heat or electric power. The sun's rays also are collected and stored naturally in the form of heat in the upper layers of the ocean which can be put to use in the production of electric energy by means of ocean thermal energy conversion (OTEC) approaches.

On the technological side, the sun's rays can be intercepted by materials that directly absorb and convert its energy to low-grade heat, or by mirrors or lenses that focus the rays onto a material to produce high-temperature heat. The higher temperature systems can be used to drive efficient heat engines in the production of electricity. The sun's rays also can be collected on photosensitive materials, in either a direct or concentrated form to generate DC electricity directly.

The systems I will discuss employ all of these means of collection and conversion, excluding biological and hydroelectric. The former is too ex-

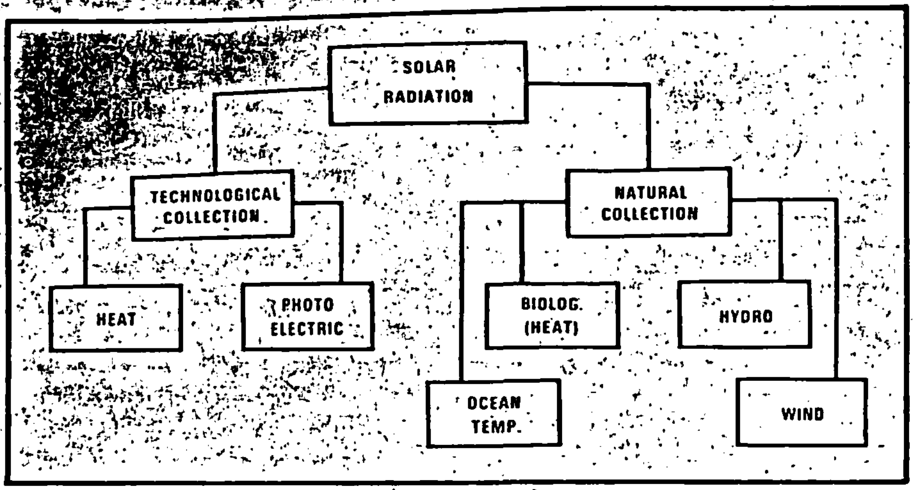


Fig. 1—Solar energy conversion.

tensive to cover here, and I'm sure that most readers are familar with the well-developed hydroelectric technologies.

When we think of solar technology it is important to have a feel for the levels of energy we are dealing with. Fig. 2 is a map of the continental U.S. showing that there is about a 2:1 variation in the average daily insolation. That is, we have some 2,000 Btu/sq ft-day in the southwest, while up around the Great Lakes it drops to less than 1,000 Btu/sq ft-day. These numbers represent the average annual insolation at the earth's surface and account for both the direct and indirect sunlight that reaches the earth in 24 hours. This is a drop from about 10,300 Btu/sq ft-day, which is the sun's intensity as it enters the earth's atmosphere (called the "solar constant"). This reduction is, of course, caused by atmospheric scattering and absorption, and by diurnal and seasonal variations.

Central Receivers

Of the several solar focusing concepts that have been proposed, the most widely pursued and accepted to date is the so-called "solar thermal central receiver" approach illustrated in Fig. 3. In this concept, the sun is tracked by a group of mirrors carried on two axis tracking mounts ("heliostats"), and the rays are reflected onto a boiler or other heat "receiver" mounted atop the tower. The concentrated solar energy thus is used to make steam in the boiler or to heat other heat transport fluids, such as liquid metals, salts, or air. In this example, steam is used to drive a turbine generator at the base of the tower. A percentage of the steam also is used to store sensible heat in tanks containing eutectic salt mixtures or hydrocarbon fluids, which can be used to generate steam to drive the turbine during momentary cloud cover or to extend the plant's operating day.

The key element of the central receiver type of plant is the heliostat, depicted in Fig. 4. This particular heliostat (designed by Northrup Inc.) is approximately 21 × 25 ft. It has a number of second surface mirrors, each of which must be aligned individually in order to achieve maximum concentration of the sun's rays on the receiver. Heliostats constitute the largest cost element of the plant, currently running around \$25 to \$30/sq ft of mirror surface for completely installed systems. Fig. 5 depicts how a pilot plant of this type would appear. Designed by Martin Marietta Corp. and Bechtel for the U.S. DOE, the plant would deliver 10 MW during daylight hours, and has 3 hours of thermal storage capacity. Some 1,500 20 × 20-ft heliostats are used to make 950°F, 1,350-psig steam in the boiler atop a 270-ft tower, which in turn drives a turbine generator at the tower's base. The entire plant occupies about 128 acres. A similar plant now being constructed at Barstow, CA, is scheduled for startup in 1981. Plants of this type will be able to convert the intercepted solar energy to net electrical output at about 20% efficiency.

While the costs of today's pilot plants are understandably high, the DOE estimates that commercial-scale central receiver plants, on the order of 100 MW or more, may be competitive with fossil-fired stations sometime in the 1990's. This projection assumes continued escalation of fuel prices, advances in central receiver system designs, and reduction of heliostat installed costs to approximately \$7/sq ft for large purchases.

Parabolic Troughs

Another type of solar thermal power generation is the linear collector approach using parabolic trough collectors as shown in Fig. 6. This is a 150-kW pilot plant that is designed to generate electric power for deep-well water

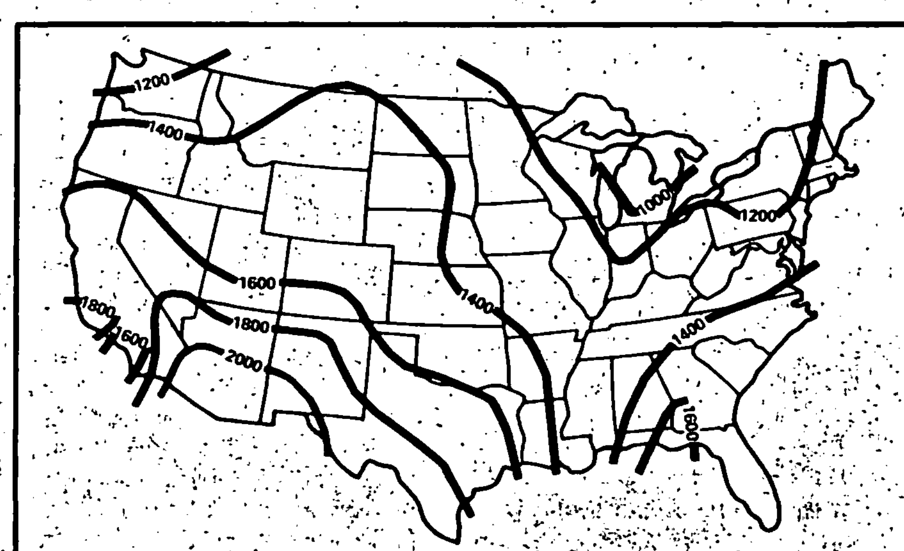


Fig. 2—Average daily insolation, Btu/sq ft-day.

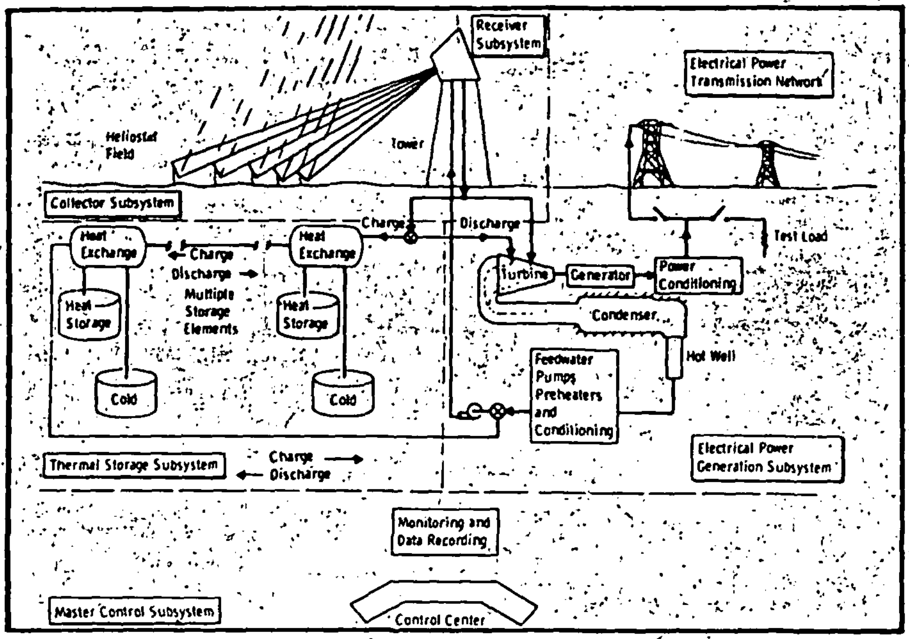


Fig. 3—Schematic of 10 MW central receiver pilot plant.

pumping. A plant of this type recently was constructed in Arizona by Acurex Corp. for DOE. The plant uses parabolic trough collectors that are capable of developing temperatures of only about 600°F, whereas central receiver plants of the type shown in Fig. 5 are capable of temperatures well above 1,000 °F. In this design, a special hydrocarbon oil is used as the collector heat-transport media which, when heated, is pumped into the top of a storage tank containing rocks; these rocks are used to store part of the heat in a thermocline. To remove the thermal energy from storage, the hot oil is passed through a boiler where toluene (a benzene-like fluid) is vaporized for expansion through the turbine.

The parabolic trough collector used is made by Acurex. Such collectors cost about $20 to $25/sq ft of aperture opening, with promise for reductions to the $5 to $10 range for advanced high production designs. The material used for the refelctor is polished aluminum. The idea is to concentrate the collected solar energy onto the receiver tube, which passes through the linear focal point of the collector. The collector rotates on only one axis as opposed to the two-axis rotation of the heliostat shown previously.

Fig. 7 is an artist's concept of the plant, based on a preliminary design prepared by Acurex and Bechtel. The collectors rotate on a north/south axis, the north being to your right in this picture. Shown are the thermal energy storage tank, plus the turbine generator enclosure just to the right of the tank. This particular plant occupies approximately 8 acres, of which 50% or so is in solar collectors. Operating at a lower temperature than the central receiver plant, its efficiency is lower: about 12 to 13%. Current indications are that busbar costs (net costs of electricity leaving the plant) for commercial-scale systems of this type may be higher than for the central receiver approach.

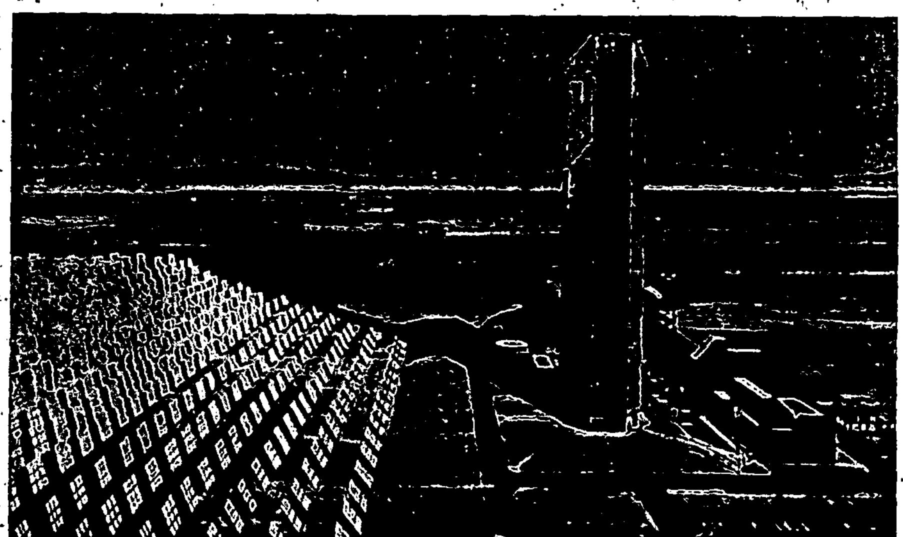


Fig. 5—10 MW central receiver pilot plant.

Photovoltaic Contenders

Fig. 8 depicts a very simple form of the photovoltaic approach to power generation. Currently, the leading contender in the photovoltaic race is the single-crystal silicon cell. This type of cell is being pursued as the major cell to be developed in the DOE program, though there are other types of cells that hold promise for the future. The single-crystal silicon cell is capable of approximately 12 to 13% conversion of intercepted solar energy. The gallium arsenide cell is capable of more than 20%. However, the goals of the DOE program are to

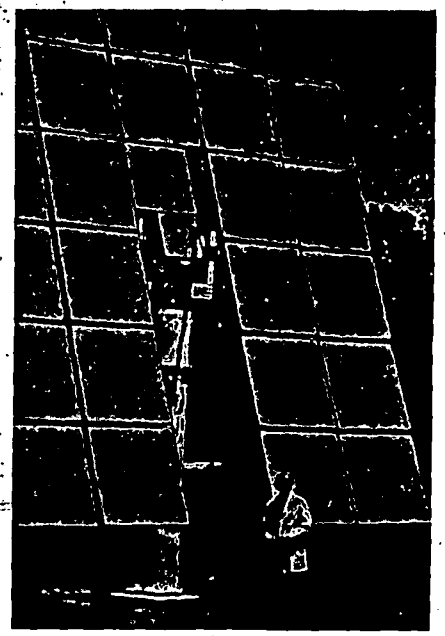


Fig. 4—Typical heliostat.

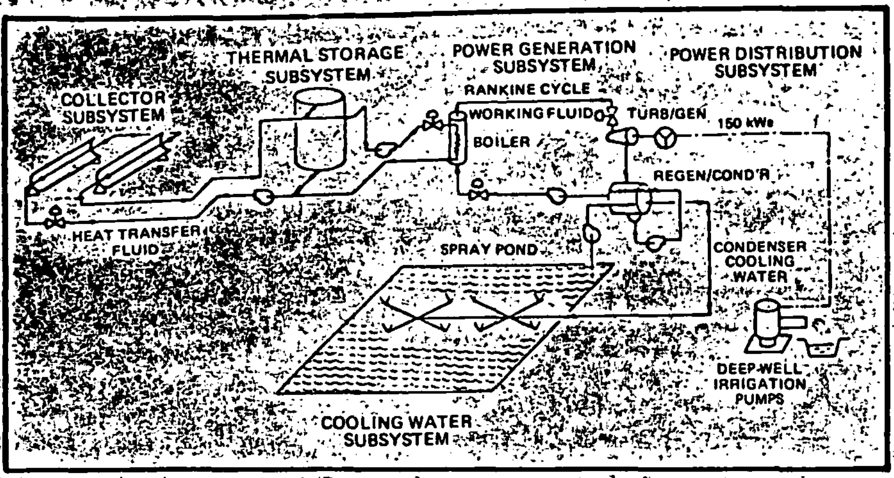


Fig. 6—Schematic of 150 MW solar powered deep well irrigation facility

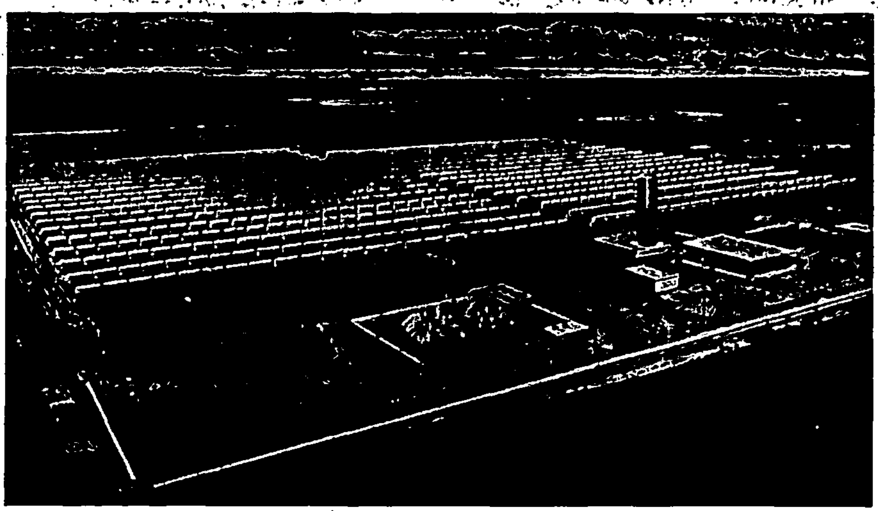


Fig. 7—150 kW solar powered deep well irrigation facility

develop the silicon cells until they achieve about 14% energy conversion efficiency, along with significant reductions in cost.

Bechtel has designed several photovoltaic power plants, not to be constructed but to find out approximately what the costs of such plants would be, assuming that the price of cells will drop to a reasonable level. Silicon cells currently cost about $10,000 to $15,000/kW, delivered ready to be installed. This, of course, is a very high price that must be brought down to more like $350 to $500/kW before it will be possible to build plants that are economically competitive in power applications. The current DOE program objective is to reduce silicon cell costs to $125 to $370/kW during the 1990's.

Fig. 9 depicts a Bechtel approach to the design of a 200 MW plant. It is made up of a number of modules, each comprising interconnected cells, arrayed as shown on the left, feeding through an inverter into a common AC distribution or collection system. One hundred such modules are used to make a total 200 MW plant. In addition to supplying cost data, the design project sought to find out what other components in the design of a photovoltaic plant might be developmental in nature, and what development programs might be necessary. Basically, the design showed that all the elements of the photovoltaic plant currently are available, at least up to the 2 MW module sizes shown here. Costs, exclusive of the cells, were estimated to be $700 to $800/kW.

Fig. 10 illustrates the DOE-sponsored, 25kW, Meade, NB, installation, which comprises 28 8- × 25-ft stationary single-cell silicon arrays that produce AC power for driving water pumps. This plant has operated successfully since mid-1977 and was, so far as I know, the largest operating system in the world until the recent completion of a 60-kW installation at a Mount Laguna, CA, U.S. Air Force radar station. Units with up to 250 kW capacity are expected to be on line soon in the U.S. Photovoltaics are reliable once they go through an initial shakedown period of a year. They seem very reliable thereafter.

Ocean Thermal Energy

Turning now to those solar technologies that take advantage of natural collection, I would like first to explore the ocean thermal energy conversion (OTEC) approach. As shown in Fig. 11, ocean surface temperatures in the equatorial regions of the world can be as high as 75 to 80°F, while at 1,500 to 2,000 ft beneath the surface temperatures can be below 40°F. Hence, if a condition is established to bring the water at these two temperatures together in a usable manner, we would have the basis for a heat engine cycle that could generate electric power. To do this, we need working fluids capable of evaporation and condensation within this temperature range. Most designs proposed to date use ammonia as the working fluid. The idea is to

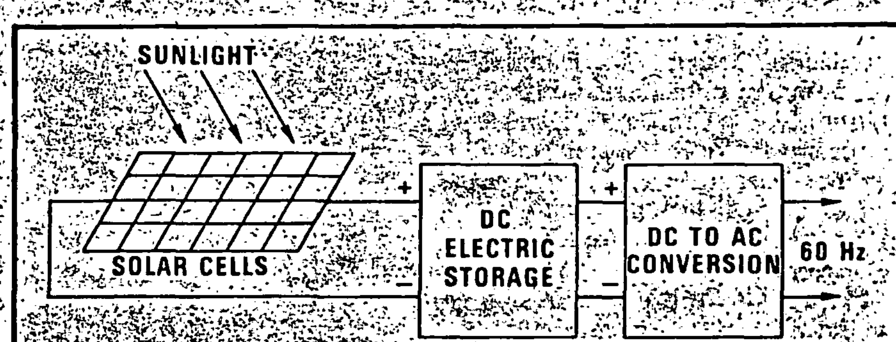


Fig. 8—Solar photovoltaic generation

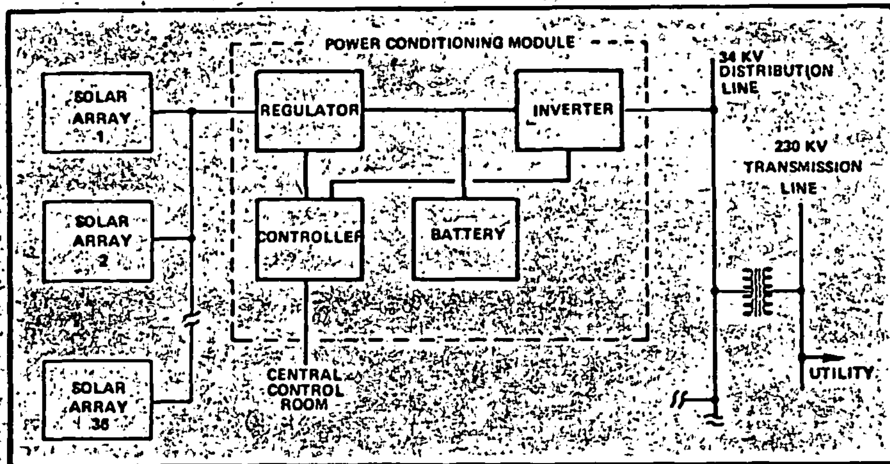


Fig. 9—Schematic of module of 200 MW photovoltaic power plant.

take the warm surface water, pump it through an evaporator, and evaporate the ammonia, which then is expanded through a turbine. The ammonia then is condensed in a condenser by water pumped from the depths, and recirculated back to the evaporator.

A problem with a cycle of this type is its inherent inefficiency. The maximum Carnot cycle theoretical efficiency for an OTEC cycle at 40° temperature difference is about 6%. In practice, we can expect to achieve a little over 2%. This requires very large heat exchangers and pumps to circulate and transfer heat from and to large amounts of sea water.

Fig. 12 represents a concept for an OTEC developed recently by Lockheed Missiles and Space Corp. Bechtel provided the energy conversion design for this plant. The design incorporates a spar-buoy configuration; the buoy itself is roughly 300 ft in diameter and has detachable power modules. Each of the four modules has an evaporator at the top and a condenser at the bottom (the horizontal cylinders). The evaporators are warmed by water from the surface, which is brought in through the round plenum surrounding the top of the buoy. It is pumped through the evaporators and back out into the sea. A telescoping pipe below the buoy extends to a depth of 1,500 ft or more. The cold water pipe for this 160-MW power plant carries about 65,000 cu ft/sec of seawater to provide necessary cooling.

This technology requires considerable development to overcome such problems as biofouling, corrosion, cold-water pipe design, transmission line connections to shore, and reliable operation at sea. It has the distinct advantage, however, of being the only solar technology that derives its energy directly from naturally stored heat, thus eliminating the need for constructed energy storage.

Because of the technical development that remains to be accomplished, OTEC costs are currently uncertain. However, most contractors to the DOE OTEC program have estimated that they will be competitive with conventional sources by the late 1980's or early 1990's.

Wind Energy Turbines

Wind power has a large potential application for remote sites around the world where supply from a utility grid is not possible or practical. Some, however, believe that wind turbine "farms" will become a reality for practical application in large utility systems. Fig. 13 shows the internal workings of a horizontal axis wind turbine of a type currently being

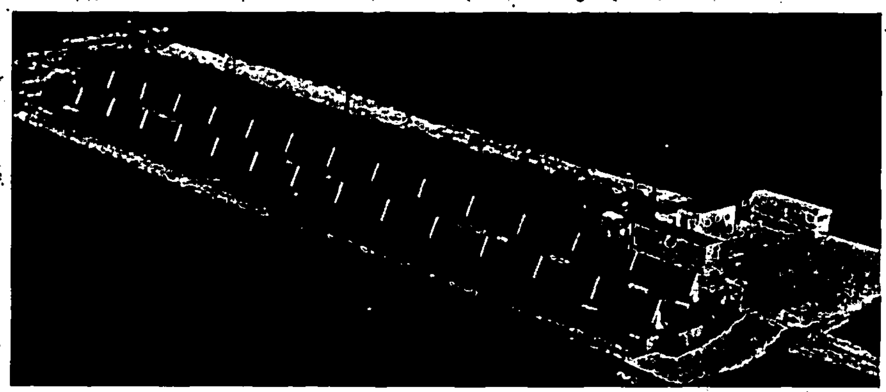


Fig. 10—25 kW photovoltaic plant at Meade, NB.

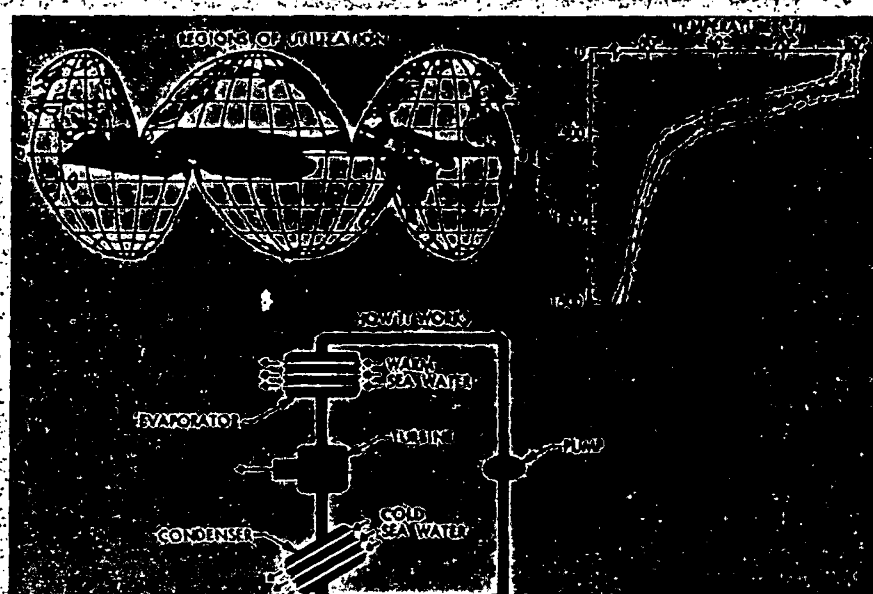


Fig. 11—The OTEC concept.

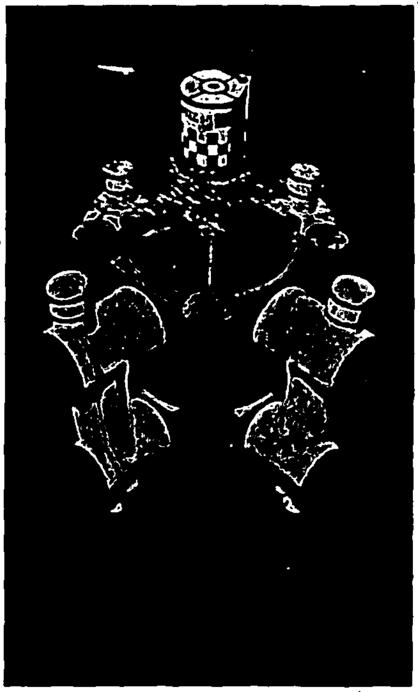


Fig. 12—160 MW OTEC plant.

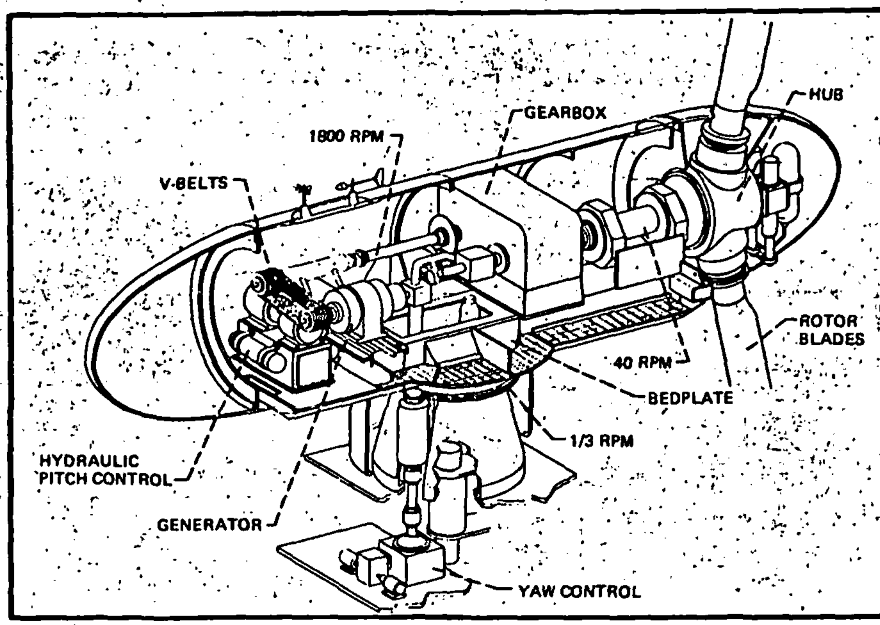


Fig. 13—Typical horizontal axis wind turbine.

developed and operated under a joint DOE/NASA program. Typically, wind speeds of 8 to 10 mph are required to commence generating power. The rotation of the blades then is held at a constant 40 rpm by means of variable pitch control and load control. The rotating hub drives a synchronous AC generator at constant rpm through a gearbox. The machines usually are rated at wind speeds of around 18 to 22 mph, and can generate power up to speeds of about 40 mph, above which the blades are feathered, and generation is halted. A yaw control orients the blades into the wind.

A number of horizontal axis machines are currently under development up to about 3 MW capacity, which is about as large as available materials can be applied to meet maximum blade stresses. Fig. 14 is a photograph of a DOE/NASA machine installed in 1978, which is operating successfully into a utility grid in Clayton, NM. It is rated at 200 kW at 18 mph wind speed. The blade diameter is 125 ft. A 2-MW machine of this type recently was put on line by DOE/NASA in Boone, NC. Performance data on this unit are not yet available.

Other types of wind machines have been proposed. Probably the second most popular proposal has been the so-called "Darrieus" wind turbine, which is a vertical shaft machine, but which is less efficient than the horizontal wind turbines shown here.

Some of the problems in operating wind turbines result from varying wind speeds and problems created by wind speed differences between the base of the tower and the top of the blades, with much higher speeds at the top. There are also problems of wind shadowing caused by the tower itself, problems with radio/TV interference, and, of course, having sufficient wind to operate the generator. Nevertheless, experiments to date indicate that wind machines will find their way into practical application.

Geothermal

Types and Distribution

When we think of geothermal resources, we think mainly of hydrothermal resources in two categories: (1) vapor (steam) dominated and (2) liquid dominated. The liquid is present in the form of a brine (Table 1). There is a considerable history for the development of steam resources, going back to 1913 when the Italians started developing their fields at Lardarello. A lot of work on steam-type resources has been done since about 1960 at The Geysers, in California. In the case of brine resources, the New Zealanders were the pioneers. They have done a considerable amount of work, starting in the 1950's, but there is also a lot going on in other areas of the world at the present time.

Another important resource, geopressured zones, are found in various parts of the world, but particularly in the U.S. along the Louisiana and Texas gulf coasts. There, pockets of hot water and methane have formed in

TABLE 1 – CLASSIFICATION OF RESOURCES FOR GEOTHERMAL POWER APPLICATIONS

Resource	Temperature Characteristic	Salinity*	First Commercial Operation
Hydrothermal			
Vapor dominated	340 to 385 F	–	1913
Liquid dominated	300 to 600 F	0.1-26%	1958
Geopressured	300 to 400 F	4-10%	1986
Hot dry rock	300 to 550 F	–	1990
Magma	1,200 F	–	2020+

*Note: seawater about 3.5%

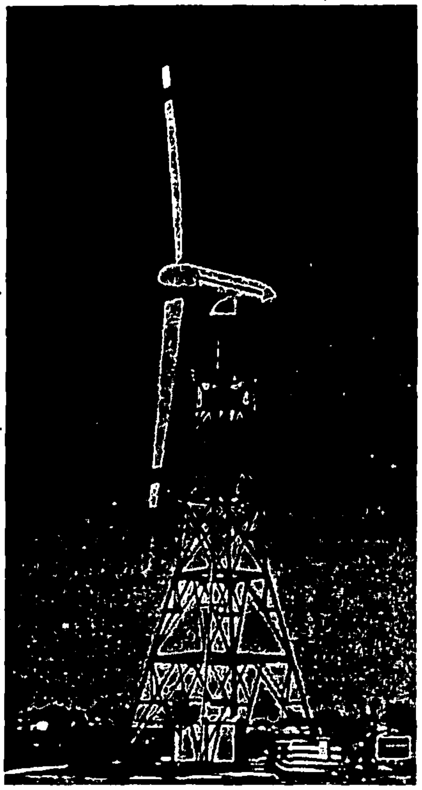


Fig. 14—200 kW horizontal axis wind turbine at Clayton, NM.

sedimentary basins as the result of silt and organic matter washed down by rivers from the continent over many millions of years. These are moderate temperature resources (about 350°F), very high pressured, and saturated with methane. This is potentially a very large resource for the U.S., if economic ways can be found to get it out of the ground. It exists at depths between 15,000 and 20,000 ft, which makes it a difficult resource to tap.

The hot dry rock resource is potentially a very large worldwide resource and is now being developed in the U.S. However, the time for its commercialization is still years away. Hot dry rock, as its name implies, is nothing but geothermal heat without water; therefore, water is brought to the hot rocks to be heated.

The world's geothermal generating capacity now on line or projected to be so by 1982 is considerable, as shown in Table 2. The U.S. has the largest single plant installation, mainly because of the ease with which it can take advantage of the steam resource at The Geysers. Italy has a large steam field but apparently has no plans for expansion in the near term. New Zealand has an active program for expansion of its brine-type resource. The Philippines and the U.S. have the most active brine resource development programs.

TABLE 2 – WORLD GEOTHERMAL GENERATING CAPACITY (1979), MW

Country	Operating	Under Construction Or Planned To 1982
U.S.A. (Geysers)*	663	861
(Others)		208
Italy*	420	—
New Zealand	100	100
Japan*	165	101
Mexico	150	30
El Salvador	60	35
Philippines	169	600
U.S.S.R.	6	58
Iceland	3	60
Turkey	1	—
Guatemala	—	30
Nicaragua	—	50
Indonesia	—	33
Total	1,737	2,166

*Steam resource (Japan partial)

Geothermal resources are found in areas of volcanism throughout the world, with some of the following plants in operation: San Salvador in Central America, Cerro Prieto in Mexico, The Geysers, and Valles Caldera in New Mexico, where Bechtel is designing and will manage the construction of a 50 MW plant. There is a lot of activity in Japan, the Philippines, and New Zealand. On the Atlantic side are similar resources. In most cases, little land is associated with the Atlantic strip because it exists in the middle of the ocean. Some of it enters European land areas, however, where the Italian fields exist.

Fig. 15 shows the location of geothermal resources in the U.S. Almost all the resources of any value exist in the western states. The star on the coast of California is The Geysers field, which is the only location outside national parks in the U.S. where steam is found in significant quantity. The vertical crosshatch locates the brine fields that have been identified throughout the western states. The dotted background indicates hot dry rock, which is a very large resource. In Texas and Louisiana the geopressured fields are along the coast. Fig. 16 in-

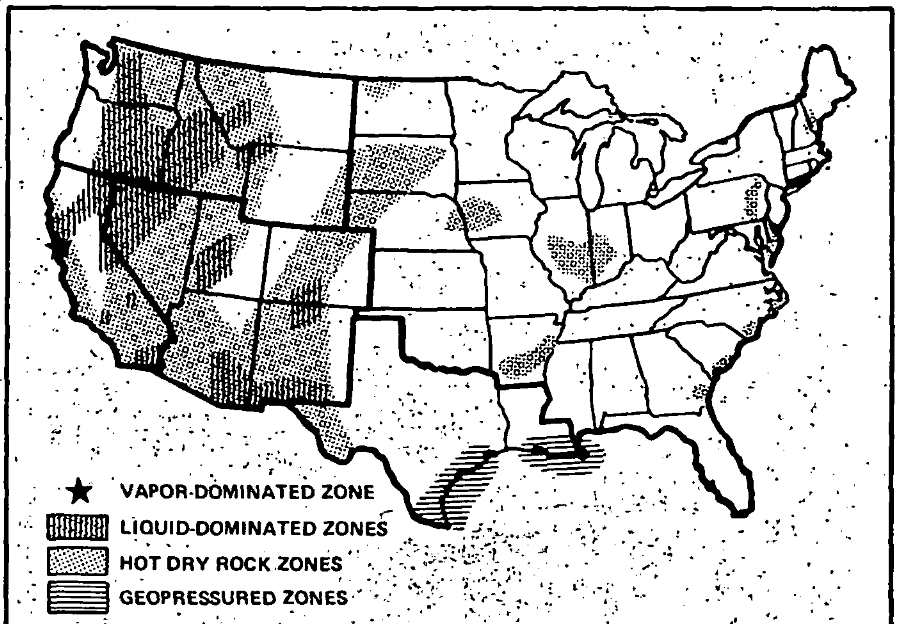


Fig. 15—Location and type of U.S. geothermal resources.

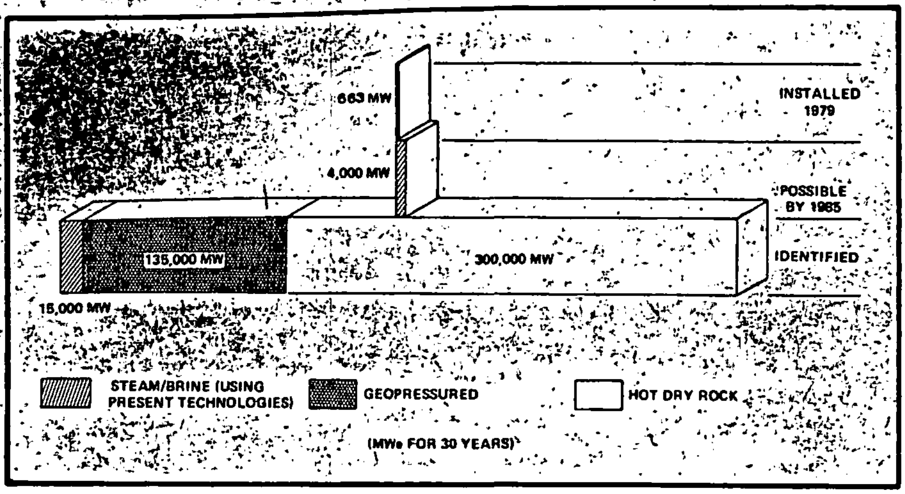


Fig. 16—Potential U.S. geothermal generating capacity.

dicates the relative quantities projected for these various resources in the U.S. The small box on the top represents current U.S. production; all is steam capacity at The Geysers. Some very good brine fields also have been identified which, along with known steam resources, represent about 4,000 MW of possible hydrothermal development by 1985. As much as 450,000 MW, for more than a 30-year life of the potential geothermal resource, has been tentatively identified among all the various types of resources. Of these, hot dry rock is the largest.

In the U.S., geothermal is taken seriously. It is a potentially viable and economic resource. Fig. 17 projects a feasible rate for new geothermal plants to come on line during the balance of this century. Little is expected to happen in hot dry rock until perhaps 1990 or 1995.

Conversion Systems

A number of cycles have been used and/or proposed for the conversion of geothermal energy into electricity. Shown in Fig. 18 are just four of them. The upper two are actually very common now. The one on the left is a simple steam cycle, where the steam is brought out of the ground and cleaned up slightly before it goes into the turbine. Then it is condensed and usually reinjected into the ground. The Geysers and the Italians at Lardarello use this process. The flashed steam approach is used now in most of the brine fields. This approach can use single-stage flash, as shown, or it can be multistage.

Some of the more advanced brine cycles, two of which are shown at the bottom of Fig. 18, are designed for maximum efficiency in lower temperature applications. Hence, in the flash binary cycle, shown on the lower left, the brine is flashed, which then vaporizes a working fluid (normally a hydrocarbon) selected for efficient turbine performance at the available temperatures. This is expanded through the turbine in a closed working fluid circuit that maintains a clean, long-life turbine. The separated and condensed brines then are reinjected. In the process on the lower right, the brines are not allowed to flash, thereby reducing some of the problems of scaling and corrosion that are caused by flashing the brine. A significant additional advantage of this completely closed loop configuration is that hydrogen sulfide in the brine is isolated from the atmosphere. However, downhole pumps are required in the wells to prevent brine flashing.

Other designs are under development in the U.S., like total flow turbines, where the entire two-phase brine-dominated flow from the wells passes directly through a single turbine. There are also direct-contact flash proposals, where the hot brine is mixed directly with a hydrocarbon working fluid. The working fluid is flashed without going through a heat exchanger.

Plant Design

Fig. 19 illustrates the plot plan of a typical two-stage flash power plant of 50 MW rating. Note that it occupies only about 10 acres while the surrounding field normally would occupy about 400 acres, assuming a 5 to 6 MW capacity per well and about 40 acres per well.

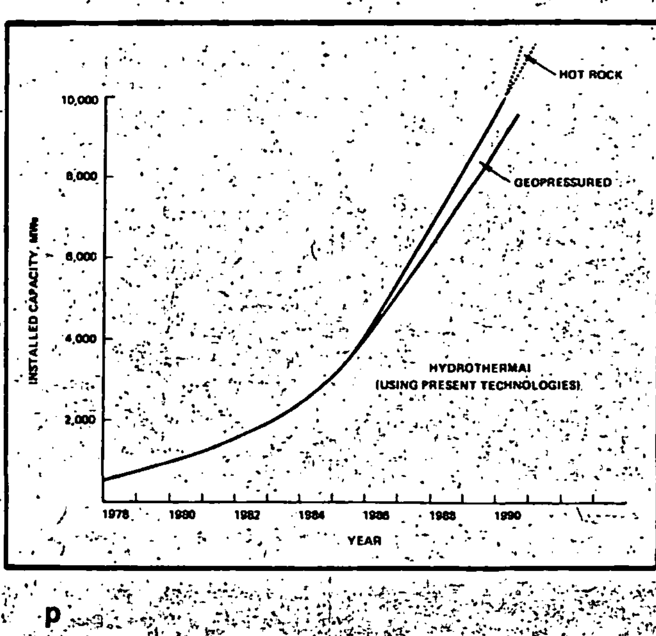
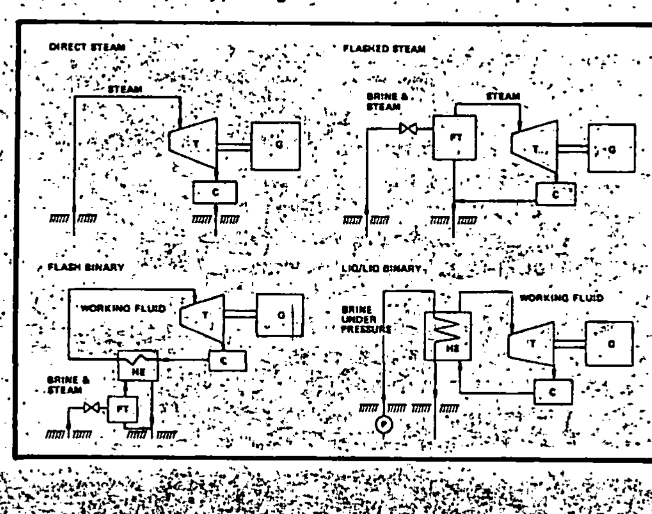


Fig. 17 (at left)—Projected U.S. geothermal power generating capacity.

Fig. 18 (below)—Typical geothermal conversion processes.



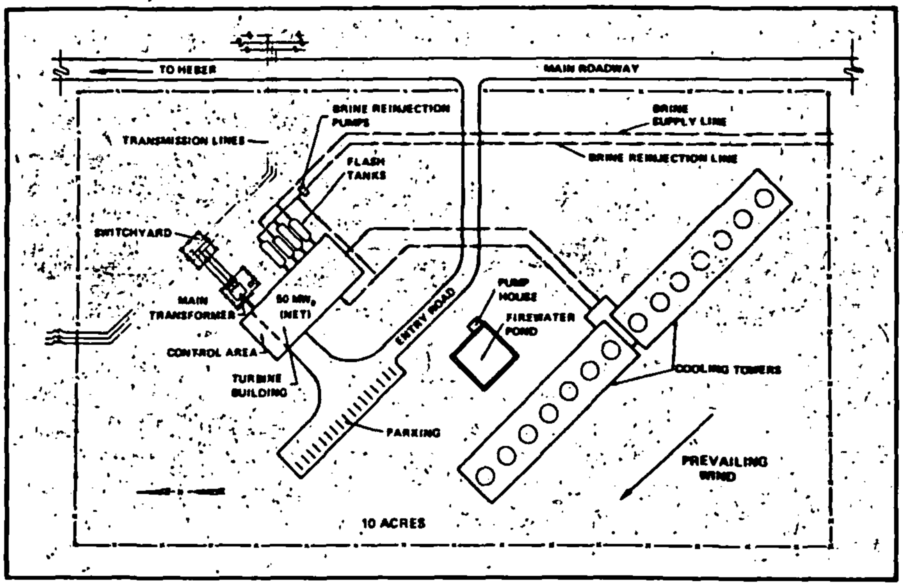


Fig. 19—Plot plan of 50-MW flashed-steam power plant.

TABLE 3 – GEOTHERMAL TECHNICAL PROBLEMS

Reservoir production, performance, and longevity
Reservoir injection
Scale and corrosion
Equipment design and reliability
Two-phase flow and stability
Subsidence
Water use
Air quality
Disposal of solid and liquid wastes

Like solar, relatively low capacity is characteristic of geothermal generating units because of the energy gathering problem. That is, there is a limit to how far the fluid can be moved without exceeding the economic viability of the system. Therefore, geothermal units rarely exceed about 110 to 150 MW. A very lively field with a great amount of a high temperature resource might justify larger units. But geothermal plants now are relatively inefficient; they have about 10 to 12 % energy conversion efficiencies operating from 400°F brine.

Every technology has its technical problems, of course, and geothermal is no exception (Table 3). Most of these problems are solvable, but experience in brine-type plants is limited at present. It is apparent that geothermal is a depletable resource; it loses temperature and pressure from wells with time. Design of geothermal power plants must consider this in order to optimize the size of the units for brine conditions over the operating life of the plant. Designers have learned a great deal about geothermal plants through desalination technology experience involving designs of large plants for desalting brackish water and seawater. Seawater has about 35,000 ppm dissolved solids, well within the range of requirements for many geothermal brines.

Busbar costs for geothermal power generation are, of course, a matter of record in the U.S. for steam plants, being on the order of 2.7¢/kWh at The Geysers. Projected costs for brine plants in the U.S. also are very promising.

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Unconventional Gas Resources

Jeffrey B. Smith, U.S. DOE

Introduction

The gas shortage is going to be with us for some time to come. If we can set aside political and industry rhetoric (along with subjective personal opinions), we still are confronted by two serious "facts of life": (1) for almost a decade the U.S. has been consuming natural gas at a greater rate than we have been finding new reserves; and (2) there is a finite amount of natural gas present within the earth's crust. Much of the known and easily exploitable sources of gas (the so-called "conventional" sources, such as the high permeability sand reservoirs of the Tertiary sequence along the Gulf Coast) already have been developed; their production is declining rapidly. The total producible reserves from conventional gas reservoirs amount to only 216 Tcf, less than an 11-year supply.

However, several large potential resources of natural gas remain to be developed. These "unconventional sources" have low permeability and/or peculiar producing characteristics. The DOE program for development of these unconventional sources of gas is called the enhanced gas recovery (EGR) program. The primary goal of this program is to provide a data base of resource characterization and production technology that will lead to commercial development. DOE will encourage and support industry participation in developing and demonstrating technologies needed to reach this goal.

Unconventional Resources

Four major unconventional resources of gas have a high potential for commercial development. There are other unconventional sources (such as gas hydrates) that are too poorly defined to warrant a major development thrust at this time. The four unconventional sources of gas currently included in the EGR program are:

1. The carbonaceous shales of Devonian age in the Appalachian, Illinois, and Michigan sedimentary basins are the targets of the Eastern Gas Shales Project (EGSP).
2. The low permeability, low porosity so-called "tight" gas sandstones of the Upper Cretaceous/Lower Tertiary in the Rocky Mountain areas constitute the resource target for the Western Gas Sands Project (WGSP).
3. The free methane trapped in coal beds of both the eastern and western U.S. constitute the Methane from Coal Beds Project (MCBP).
4. The abnormally high pressured, high-temperature saltwater aquifers of the Texas-Louisiana gulf coast are targets of the Geopressured Aquifer Project (GPAP).

Basic implementation strategy for these EGR projects involve (1) assessing and characterizing the resource potential of the resource; (2) conducting cost-shared field testing with industry to improve, develop, and demonstrate various stimulation and production technologies; (3) coordinating EGR activities within DOE and with other federal agencies (such as the Bureau of Mines) to minimize duplication; and (4) aiming all projects toward *commercial* development of the gas resources.

EGSP

What type of "geological animal" is the EGSP dealing with? While gas undeniably is related to the occurrence of natural fracture systems within the shale, the overall producing mechanism and precise location of fractured, gas-bearing locales within each basin is still poorly understood. By developing reliable resource characterization techniques and applying effective stimulation technologies we intend to elevate the Devonian shale from the status of a potential gas resource to that of a proven gas reserve. Once we have done this the private sector can take over the large-scale commercial development of the Devonian shale gas resource.

WGSP

The second largest project (both in terms of complexity and level of funding) is the WGSP. The primary targets for this project are the low permeability (<1 md) gas sandstones of the Piceance, Uintah, and Greater Green River basins and the Northern Great Plains Province. Project success in these four primary geologic locales will permit investigating additional low permeability sandstones in 16 other sedimentary basins. It appears that the only practical means of increasing permeability and resultant flow rates from these sandstones lies in the use of massive hydraulic fracturing techniques. Unfortunately, it is still too early to design such jobs with predictable results.

MCBP

The MCBP is to be involved in producing and utilizing methane derived from coal beds. The coal, like portions of the Devonian shale, is impermeable, highly fractured (termed "cleat" by mining personnel), and produces gas by desorption. The greatest similarity between shale gas production and methane drainage production is their generally unpredictable natures, especially with regard to predicting open flow production rates before production testing the well. The EGR project in methane drainage will be confined to unminable coal beds – those too thin and/or deep to be conventionally mined.

GPAP

The fourth EGR project involves the Div. of Geothermal Energy and the Enhanced Gas Recovery Branch in a joint venture to develop the energy resources (both geothermal and gas) of abnormally high pressure, high-temperature, saltwater aquifers. Flowing a well at a rate of 40,000 BWPD for 20 years with a minimum gas satuation of 30 scf/bbl (1.2 MMcf/D) is a pretty good trick. If this were Saudi Arabia and we were talking about 40,000 B/D of light Arabian crude, the economic picture would be quite different. There is a large potential source of gas in these aquifers, but the risk and technical problems are formidable. I once read, somewhere, that there are tons and tons of gold in a cubic mile of seawater; the "trick" is to get it out and yield a profit for your labor. This analogy applies to all of the unconventional sources of gas, but it is especially pertinent with regard to the geopressured aquifers.

Summary

The primary objective of the EGR program is to stimulate commercial development of large known gas resources. There are indeed very impressive reserves of *potentially* (and I emphasize the word "potentially") recoverable gas. However, the wide range of the estimates limit the reliability of EGR reserves figures at this time. To turn these estimates into commercial reserves capable of being put into the pipeline, the DOE's Enhanced Gas Recovery Branch is following stated goals: (1) to provide a reliable data base of technological information; (2) to improve upon existing and/or develop new stimulation and production technologies; and (3) to demonstrate the commercial feasibility of successful techniques.

Of all fossil energy programs in DOE, the EGR program has the greatest potential for near-term impact. Relative to the building of coal gasification plants and the like, EGR activities have fast response time (weeks to drill and complete a well vs months or years to construct a plant), it costs less to do the work, and has minimal effect on the environment.

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The Application of Petroleum Engineering to Geothermal Development

V.E. Suter, Union Oil Co. of California

Anyone with geothermal experience can readily attest that geothermal operations are a natural extension of oil and gas operations. A geothermal company and an oil company need the same type of people to do the same kind of work. In the geothermal industry, geologists and geophysicists define prospects through surface geology, analysis of surface seeps, magnetics, gravity, and resistivity surveys – techniques similar to those used in the petroleum industry. In addition, shallow (250-ft) temperature gradient holes often are used in geothermal operations.

Landmen take geothermal leases that are patterned after oil and gas leases. Exploratory drilling is done with the same drilling contractors and same drilling rigs, with minor modification. Drilling foremen and drilling engineers share the same objective of making the most hole, in the shortest time, at the least cost, with a proper completion. Petroleum engineers test the wells, design the completions, determine the reserves, make economic calculations, work with the tax assessor, and manage the reservoirs.

Production engineers build roads, locations and pipelines, install gas/liquid separators and meters, and operate production and injection facilities. A contract to sell steam to a public utility is required. Various governmental regulations, permits, environmental concerns, and public affairs pose similar problems in both industries. Also required of both are top management people who are acquainted with geologic risk, prepared to accept million dollar dry holes, willing to bid competitively at lease sales, and able to invest large sums based on a technology not yet fully proven.

Successful geothermal development requires in-depth financial ability similar to that required for petroleum development. A high capital investment is required early for leases, geological and geophysical work, and exploratory and confirmation drilling. After discovery, it usually takes many years before any income can be realized because of the lengthy permitting and construction time required for a generating unit. During that period, more capital is required for development wells, pipelines, and production and injection facilities.

Differences in Geothermal and Petroleum Operations

Although there are many similarities between the two industries, there are also some differences that must be learned by those making the transition from oil and gas to geothermal.

The most obvious are high geothermal temperatures (over 600°F in some reservoirs), which must be considered in all operations. High temperature affects drilling mud, cement, drillbit bearings, and lubricants. It makes rubber and plastic products useless, including drillpipe protective rubbers and downhole packers. Geothermal wells require special logging tools, directional instruments, and pressure bombs. Casing and pipeline design must cope with the stress and strain of thermal expansion due to temperature changes. Reservoir engineers must consider heat balance, phase change, temperature buildup phenomena, heat conservation, and proper disposal of waste heat.

Geothermal fluids will not burn, and pressures encountered are generally less than those in oil and gas operations. However, the risk of a well blowout is still present. Drilling mud, of sufficient weight to control pressure, must be kept cool by timely circulation, or it can "flash" or boil with explosive force. Of course, proper drilling procedures and appropriate blowout prevention equipment make virtually all drilling operations safe and routine.

Fluid flow rates in the geothermal industry are generally an order of magnitude larger than in the petroleum industry; instead of using B/D or MMcf/D, the geothermal industry uses gal/min and lb/hr.

For example, production wells at The Geysers field average 150,000 lb/hr of dry steam, and about 13 wells can supply the standard 110-MW generating station with the required 2,000,000 lb/hr of dry steam. To produce at these same weight rates, natural gas wells would produce at 70 MMcf/D, or a 13-well total of almost one billion scf/D. These large flow rates, coupled with low pressures (500 psi reservoir pressure and 100 psi turbine intake) require large pipe sizes. The steam delivery line to the turbine consists of twin 42-in. pipes. Production well casing sizes range from 9⅝ to 11¾ in.

At The Geysers, about 20% of the steam produced eventually is reinjected into the reservoir as steam condensate. The current injection rate is about 5,000 gal/min, or in oilfield units, 170,000 B/D. This qualifies The Geysers as a rather large water injection project compared to oilfield waterflood operations. This 170,000 B/D is being injected into five wells, all with a vacuum at the wellhead resulting from low reservoir pressure and high reservoir flow capacity.

In most other areas, geothermal reservoirs contain hot water rather than dry steam, and production at the wellhead is normally a mixture of hot water and flashed steam, measured in lb/hr of total mass flow. A good well will produce 500,000 lb/hr, and some outstanding wells have been tested at rates exceeding 1,000,000 lb/hr of total mass flow. This is the oilfield equivalent of about 40,000 B/D for a good well and 80,000 B/D for an outstanding well.

Well Testing

When a wildcat geothermal well encounters hot water at acceptable temperatures, well testing to evaluate the "discovery" is performed while the drilling rig is on location. Geothermal fluids normally cannot be disposed of on the surface, and there usually is not an available place to inject them other than back into the same well. Pressure bomb performance in hot geothermal wells is less than reliable, and the calculation of bottomhole flowing pressures, based on surface measurements, is difficult due to the complexities of two-phase vertical flow. Short tests taken under these conditions do not allow accurate well evaluation; improved methods are needed.

Well Stimulation

Geothermal exploration efforts are designed to discover abnormally hot areas where commercial temperatures can be reached at a reasonable drilling cost. Successful commercial development also requires that the hot rock contain fluids (steam or water) and a very large flow capacity. Most geothermal wells produce from fractured reservoir rock, but adequate fractures are not always found. "Dry holes" have been drilled in the middle of The Geysers field. The reservoir fracture system may not be far away, however. Some dry holes have been directionally redrilled a few hundred feet away and have become commercial producers.

Therefore, there is a need to develop a technique for creating artificial fractures in geothermal wells. Hydraulic fracturing of a noncommercial producer does not appear to be practical because of the high productivity required for a commercial producer. Water injection tests show that these noncommercial wells will take over 1,000 gpm with a vacuum at the wellhead. Explosive stimulation, now being considered, must await the development of an explosive that can be placed in the high temperature geothermal wellbore without detonating prematurely.

Reserve Estimation

After a geothermal field is discovered and a few confirmation wells have been drilled, reserves need to be determined to decide if electric generation facilities can be expected to yield a satisfactory rate of return. There normally is at least a 6-year time lag from the discovery well to commencement of income. This lag traces to the time required to prove reserves, negotiate a contract, get the necessary permits, drill development wells, install pipelines, and build generating units and transmission lines. Any unnecessary wells drilled early in this period have zero return on investment until power generation starts.

Therefore, the challenge is to prove reserves and obtain a steam sales contract involving the least number of wells and in the shortest time.

Volumetric reserve calculations are of questionable value because most of the effective porosity may exist in reservoir fractures where the average value cannot be determined from core or log analysis. The base of the producing interval hardly ever is known due to inability to drill that deep. Production tests, with reinjection of most of the produced fluid into another well, do not create enough net reservoir withdrawals in a reasonable time to create a measurable reservoir pressure decline for use in calculating reservoir size.

Extensive reservoir pressure interference tests have been used successfully to determine reserves. Such studies involve producing some wells, injecting into others, and accurately monitoring pressure response in observation wells. By using petroleum reservoir engineering equations, reservoir parameters of porosity thickness (ϕh), permeability thickness (kh), and boundary conditions can be varied until the best pressure history match is obtained. Using the best value of ϕh, reserves per acre then can be calculated.

Secondary Recovery/ Reservoir Management

Assume a closed dry steam reservoir at 500°F and 500 psia with a 10% porosity. Calculations show that less than 2% of the total reservoir heat is in the steam and more than 98% of the reservoir heat is in the rock. Therefore, with no reinjection, total heat recovery at abandonment caused by pressure depletion will be less than 2% of the total heat in place.

Water injection to recover some of the heat in the rock seems feasible. Radioactive tritium tracers[3] have been used to prove that some injected water is vaporized and produced as steam from nearby producing wells. Water injection also has caused some nearby producing wells to produce wet steam, creating expensive liquid separation and liquid disposal problems to obtain the dry steam required by the turbines. Unresolved questions include: Where to inject? At what rate? How much additional heat recovery will occur? How much injection cost can be tolerated, based on this additional recovery?

Assume a closed, hot water reservoir at 500°F and 2,000 psia with a 10% porosity. The amount of heat contained in the reservoir fluid will be much greater for a hot water reservoir than a dry steam reservoir because the density of hot water is many times that of steam.

As this reservoir is produced, the pressure will drop below saturation pressure and some boiling will take place in the reservoir. The boiling will extract heat from the rock. Modeling calculations indicate that heat recovery could be about 1.2 times the original heat in the water.

Water injection to maintain pressure and to extract additional heat from the rock may yield recovery of up to two times the original heat in the water.

Hot water reservoirs can have complicated behaviors.[4] The actual rate of temperature equilibrium between reservoir rock and geothermal fluids is unknown, reservoir boiling may create formation plugging with scale as dissolved minerals concentrate, and a decline in reservoir pressure may create unacceptable land surface subsidence in certain unique circumstances. Also, surface disposal of geothermal fluids in the U.S. has not been found environmentally acceptable.

Therefore, geothermal waters probably will be returned to the reservoir for disposal, pressure maintenance, and heat recovery. The unresolved questions are similar to the dry steam case: Where to inject? At what rate? How much additional heat recovery will occur? After the injection water front reaches the production wells, how long will it be before the thermodynamic front reaches the producing wells?

Assume a geothermal reservoir partially filled with hot water with a steam cap. This reservoir will have all the complications of both previous examples, and the determination of the optimum reservoir management plan will be a real challenge.

Geothermal reservoir modeling efforts are being used in an attempt to answer some of these questions. These models are similar to petroleum reservoir models with the added complication of demanding a heat balance as well as a mass balance.[5]

Drilling Mud, Cement, and Bits

The application of petroleum engineering to the drilling of geothermal wells has contributed partial solutions to many problems, but further improvements are needed.

High temperatures at depth adversely affect drilling mud by causing the bentonite to flocculate, creating a high filtrate loss and a high gelation condition. A forced-draft cooling tower in the mud system was found helpful. Drilling operations have been improved further by using a sepiolite-lignite mud system. The sepiolite clay mineral of the magnesium silicate family has less tendency to flocculate at high temperatures.[6]

Well casings originally were cemented using standard oilfield cementing practices, but experience showed that after several years of exposure to high geothermal temperatures, the cement weakened and became powdery. Through an extensive group research effort,[7] including cementing service companies, additives and mixing techniques have been developed to keep cement from losing its compressive strength at high temperatures. Long-term tests are in progress to assess their effectiveness.

Drillbits used for geothermal drilling have a shorter life than oilfield bits. Drilling in hard volcanic and metamorphic rock at very high temperatures results in early failure of both bearings and teeth. The matrix used in diamond bits will not withstand the temperatures encountered during air drilling in geothermal wells. Many "improved" bits have been tested but much progress is still needed.

Drilling Techniques

Most geothermal reservoirs are underpressured (below normal hydrostatic pressure), and lost circulation during drilling and cementing casing is common. Air drilling techniques can be used in dry steam reservoirs, but air, steam, and rock cuttings flowing up the outside of the drillpipe at near sonic velocity create a severe erosion/corrosion problem at the drillpipe tool joints. This reduced drillpipe life to about 10% of normal for oilfield drilling. Drillpipe life has been extended three to four times by the development of a new corrosion inhibitor[8] and by hard banding the tapered section of the tool joints. Experiments using special alloy tool joints are in progress.

In hot water geothermal fields, the use of aerated water as a drilling fluid has been successful in combating lost circulation when hole stability conditions are favorable. However, air mixed with hot salty water can create drillpipe corrosion rates in excess of 45 lb/sq ft/year. In some cases, the corrosion rate has been reduced to 1.5 lb/sq ft/year with the use of a new corrosion inhibitor, ammonia, sodium polyacrylate, lignite, and sodium hydroxide. However, geothermal brines occur in many different compositions, and, for new areas, the development of different corrosion control measures is required. Replacing the compressed air with an inert gas would reduce corrosion problems greatly, but cost effectiveness of the method still must be demonstrated.

Pipeline System Design

Pipeline design for a dry steam field must be optimized to consider pressure loss, heat loss, safe operations, and economics. Insulation of proper quality and thickness must be installed and expansion loops and skid mountings are necessary to compensate for thermal expansion and contraction during producing and shut-in conditions. Rock chips and dust produced from the formation, and any condensate from a cold startup, must be removed from the steam before delivery to the turbine. Computer programs are used to design the entire system to ensure delivery of high quality steam at the required turbine inlet pressure. Simple orifice meters suffice for steam measurement.

Pipeline design for a hot water field is several times more complex and expensive. A two-phase mixture of water and steam is produced at the wellhead and requires separation so that dry steam can be sent to the turbine and the water injected back into the reservoir. Is the best system to separate at each wellhead, only at the power plant, or at satellite stations in between? The piping system will include two-phase flow lines, dry steam lines and hot water lines that may become two-phase flow if pressure drops below the saturation pressure for the temperature involved. If expensive separators are not installed at each well, how will routine production well testing be accomplished? The possibilities include a well test manifold system and a portable well test separator.

Proper design of two-phase pipeline systems must account for thermal expansion, two-phase pressure drop, phase change, relative steam/water velocity, heat transfer, flow regime change, and the effect of high velocity slugs of water at pipeline bends.

Scale Control

All geothermal hot waters are saturated with dissolved silica, ranging from 155 to 805 ppm (as SiO_2), depending on reservoir temperature.[9] If the temperature drops below a certain limit, large volumes of silica may precipitate. This can cause plugging of injection pumps, injection lines, and injection wells, creating the need for expensive injectivity restoration work.[10]

After the silica precipitates, the water to be injected can be treated with a sludge removal and filtration system. However, the sludge disposal quantity for a 100-MW power plant could be as much as 50 ton/day.

Potential for Growth

As a reference point, a 100-MW generating unit will supply the electrical needs of 100,000 people and produce the equivalent electrical energy of about 1.3 million bbl of oil per year, or 39 million bbl over a 30-year life.

United States Potential

Outside California, geothermal electric facilities are being planned in New Mexico, Utah, Nevada, Idaho, and Hawaii. On a nationwide scale, experts believe that there is a geologic opportunity to develop 20,000 MW of electric generating capacity in the next two decades, equivalent to about 700,000 B/D of oil, or 8.5% of today's U.S. crude oil production.

As technological advances are made, there could be the potential for several times this capacity in succeeding decades. To find and develop the first 20,000 MW will require the drilling of at least 1,000 exploratory wells and 6,000 development wells at an estimated current cost of $800,000 per well. Including hook-up facilities, this will require over $8 billion in initial installation costs.

World Potential

On a worldwide basis, there are now some 30 countries active in geothermal exploration.[11] Geothermal power plants are in operation in the Philippines, Italy, New Zealand, Mexico, Japan, Iceland, El Salvador, Turkey, and the U.S.S.R. Other countries are planning for geothermal development to offset the high cost of imported oil.

The geothermal industry makes no claims of being able to solve the national or world energy crisis. However, performance over the last 10 years and prospects already identified indicate that the geothermal industry has tremendous potential for growth and will make a significant contribution to worldwide energy supplies. Much of this will be made possible by the continuing application of petroleum engineering to geothermal development.

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Mined Oil – A Valuable Resource Opportunity

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Introduction

Very little attention normally is given by the experts, or the public at large, to the fact that the majority of the oil that has been or will be discovered within the U.S. remains in the ground. The inherent limitations of oil production through surface wells, either by primary or secondary techniques, will result in a total of over 300 billion bbl of oil left in the ground after completing production by standard petroleum techniques in currently producing or producible fields. This reserve represents some two-thirds of the original quantity of oil discovered in place.

Recent work by a number of groups has shown that there is strong economic justification for extracting this remaining oil by mining and processing techniques. Table 1, taken from 1977 API reports, demonstrates the oil left in place at the end of the conventional petroleum production cycle in then-known fields within the U.S. Possible targets for oil mining operations include (1) oil remaining in place in fields and pools that have reached economic depletion by current petroleum production methods and that are not amenable to economic recovery by conventional petroleum industry techniques; (2) oil- or bitumen-saturated rocks not normally considered by the industry to constitute producible reservoirs, such as shales and diatomites; and (3) asphalt- and bitumen-impregnated rocks.

Economically Depleted Fields

A more detailed examination of the depleted fields shows that estimates of oil remaining in place after primary, secondary, and nondestructive tertiary recovery can vary widely. There is significant evidence, however, that more than half the estimated original oil in place (OOIP) remains in the reservoir after all petroleum extraction techniques have been applied. If one compares the sum of past oil production and estimated remaining producible reserves with the API estimate of total discovered OOIP as of 1975, it becomes apparent that for the U.S. as a whole, 67% of the OOIP will remain in place at the end of the

TABLE 1 – OIL LEFT IN PLACE AT THE END OF CONVENTIONAL PETROLEUM PRODUCTION BY STATE
(Not Including Diatomites, Bituminous Sandstones, Asphalts, or Tar Sands)

State	Remaining Resource (Billion bbl)
Texas	101.19
California	62.78
Oklahoma	25.62
Louisiana	22.04
Alaska	16.41
New Mexico	10.93
Kansas	10.55
Wyoming	10.46
Ohio	6.06
Illinois	5.76
Pennsylvania	5.31
Montana	3.48
Mississippi	3.05
Utah	2.89
Arkansas	2.78
Colorado	2.74
West Virginia	2.08
North Dakota	1.93
Michigan	1.79
Kentucky	1.43
Indiana	1.10
Nebraska	0.98
New York	0.88
Florida	0.58
Alabama	0.52
South Dakota	0.03
Tennessee	0.02
Miscellaneous*	0.10
Total	303.49

*Includes Arizona, Missouri, Nevada, Virginia, and Washington.

economic recovery process.

The same comparison carried out specifically for the 100 largest oilfields in the U.S. yields a figure of 63% of the OOIP remaining after full production. These figures are representative of oil fields that have been or presently are under production by conventional petroleum techniques and do not include the reserves in heavy crude reservoirs that have limited production or poor reserves data, tar sands, or oil-impregnated diatomite deposits, etc. Of this estimated economically ultimate unrecoverable resource of oil, fully 85.7% is contained in only eight states, each with a residual resource of more than 10 billion bbl (Fig. 1). Further analysis of the 1977 API figures shows that 209 billion of the 303 billion bbl of total remaining oil will be in sandstone reservoirs, 89.71 billion bbl in carbonate reservoirs, and 4.54 billion bbl in other reservoirs. Not included in these estimates, but potentially of large magnitude, are reservoirs which never have been placed in production, normally due to high oil viscosity. An example of such a field is the Paris Valley in California.

Oil- or Bitumen-Saturated Rocks

The second area of interest for the potential mining of oil is the oil- or bitumen-saturated diatomites and shales. Historically, the petroleum industry has not kept detailed records of the oil contents of either diatomites or shales because of the problems of producing from such rocks with conventional techniques. In recent years, however, with newly developing petroleum technology and the potential of mining, more interest and care have been taken in these deposits. It is now believed that such deposits in tertiary basins may constitute a significant resource. Owing to the generally high-porosity but very low effective permeability of diatomite, which results from the small individual pore size capillary effects, the potential grades of some of these fields are high.

Two fields where oil impregnated diatomites occur are the McKittrick, currently being evaluated by Getty Oil Co., and the South Belridge fields of California. Oil concentrations of up to 1 bbl/st are mentioned with regard to these deposits. There is little doubt that much interest will be aimed at the diatomites and shales in the near future, not only because of oil mining, but also because of a recent successful attempt at fracturing to induce flow in the South Belridge field.

Asphalt- and Bitumen-Impregnated Rocks

Asphalt and bituminous deposits have been encountered in the past but may not have been recorded since these occurrences were then of no commercial value to petroleum companies. Those deposits that were recorded are poorly defined in areal extent and have limited documentation available. Even those deposits with abundant surface exposures are poorly documented with regard to bituminous content, tonnage, and depth.

Partial resource estimates have been made of seven states. The estimated resources of known deposits in California, Kentucky, New Mexico, Texas, and Utah are approximately 29 billion bbl of bitumen. The potential for another substantial resource exists as poorly-exposed or unexposed bituminous deposits. Examples of large, or potentially large bituminous deposits are the Sunnyside, UT, and Edna, CA deposits.

In summary, with the three potential resources described above, it is not difficult to envision a total resource approaching 500 billion bbl remaining in the ground after present production technologies have been applied to the fullest. This is considered a valuable resource opportunity.

Mining for Oil

The mining of oil is not necessarily a new technology, since rock outcrops were mined for their oil content in antiquity and were a feature of numerous local economies as part of the Industrial Revolution. The best known historical operations are probably those conducted at Pechelbronn in France and at Wietze in Germany in the first half of the 20th century. Other attempts at mining oil were at Heide Meldorf in Germany, Franklin field in Pennsylvania, and Higashiyama in Japan. These particular operations were, however, carried out under very specific circumstances: (1) the need for strategic oil supplies during wartime at almost any cost, which was the case in Germany and Japan during World War II; (2) the need for domestic production in oil-poor nations during favorable economic times, such as European operations during the 1920's and 1930's when economies were depressed and labor was cheap; (3) the existence of a directed economy such as exists in the Soviet Union; and (4) the requirement for special grades of oil, which stimulated the attempt at Franklin field in Pennsylvania. Recently, marked increases in world oil prices and a perceived shortfall in domestic production in North America have stimulated interest in oil mining from both government and private industry. This has resulted in the planned operations in the Athabasca tar sands in Alberta and in the interest of several U.S. companies in similar projects.

Two recently released reports prepared for the USBM examined in detail the potential of oil mining. These two reports, one by Golder Assocs. and the other by Energy Development Consultants, aroused considerable interest in the potential for oil mining. The information in this article is based primarily on the Golder report entitled, "A Technical and Economic Feasibility Study of Oil Production by Mining Methods."

This study used the computerized petroleum data service of the U. of Oklahoma to examine the oil reservoirs in the U.S. and to evaluate their potential for mining. The data bank search resulted in a candidate field list of approximately 10,000 oil fields. These fields were further examined and a short list of candidate deposits was developed. From this short list, nine site-specific fields were selected and order-of-magnitude mining feasibility studies carried out. Five of the fields evaluated were conducive to underground mining techniques, and the remaining were surface mining potentials.

The five underground mining operations included two involving direct mining of the reservoir rock, namely room and rib stoping and block caving, two methods employing oil drainage, and one using mining techniques to fracture the rock prior to drainage, referred to as shatter and drain. The four surface mining systems included a modified terrace pit, a terrace mining system employing bucket wheel excavators, strip mining, and a traditional open pit. The results achieved from these evaluations varied widely, as expected, due to influence by both the methods themselves and the characteristics of the individual deposits. The underground

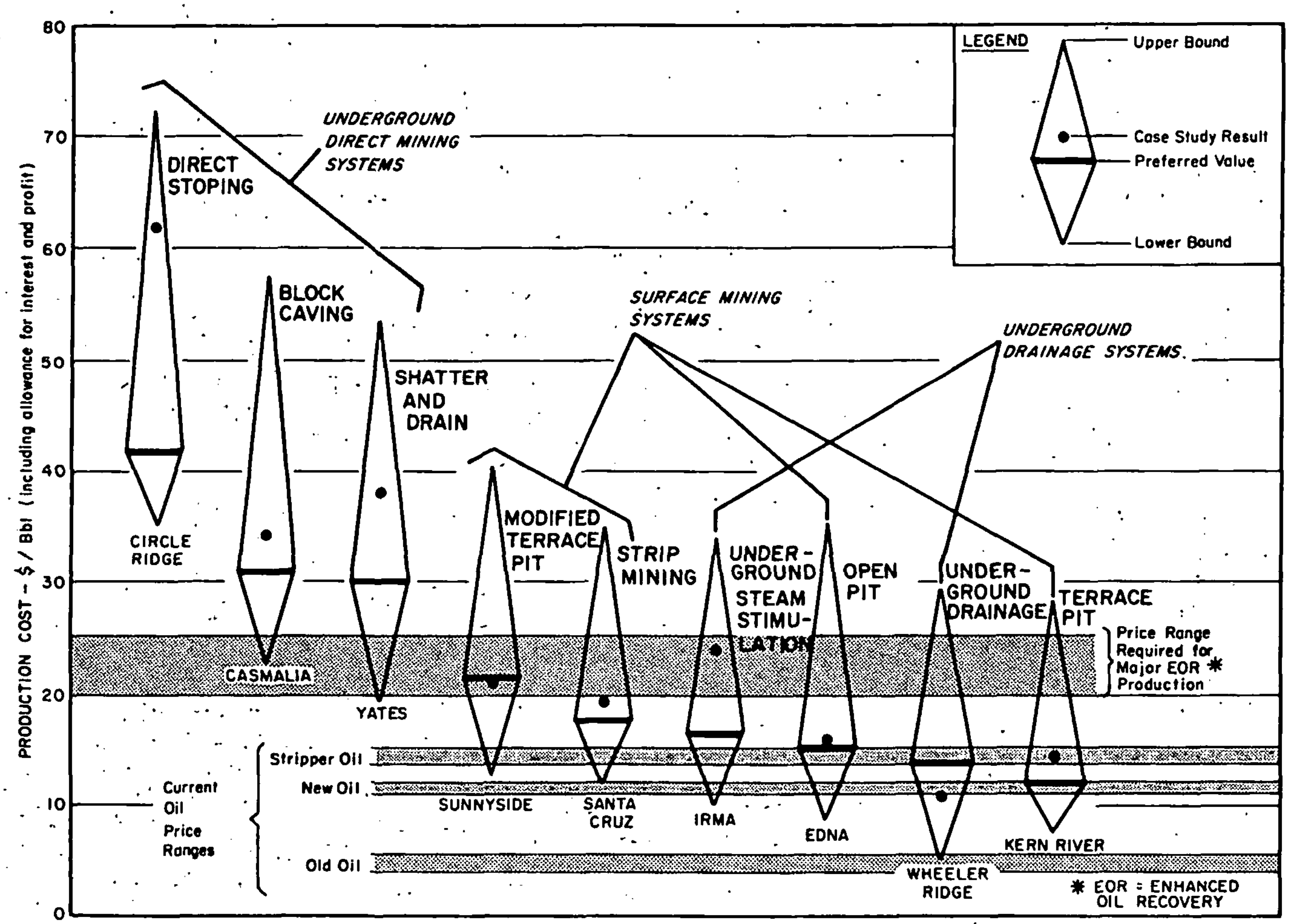

Fig. 1—Expected cost ranges for the systems and particular fields evaluated.

methods that involve mining operations in the reservoir rock showed costs in excess of $30/bbl, with the direct stoping method at over $60/bbl. These particular cases all were handicapped by low ore grades, but even when the results were adjusted to allow for a more favorable but still realistic grade, it did not appear likely that the costs would fall below $30/bbl.

The two underground drainage methods, however, gave better results, although the steam stimulation example was heavily handicapped by the thinness of the particular oil-bearing zone evaluated. Both methods show potential for production at costs between $10 and $17/bbl, provided the projected oil yields can be obtained. As would be expected, the drainage methods are extremely sensitive to any factor which affects oil yield, particularly the grade of oil-bearing rock.

The four surface mining systems are projected to produce oil at costs ranging from $21/bbl for the modified terrace system in hard rock, to $12/bbl for a large terrace pit in poorly consolidated material. These costs are particularly sensitive to ore grade, stripping ratio, and ore hardness. Fig. 1 shows the expected cost ranges for the systems and particular fields evaluated.

The conclusions of the study show that production of oil by drainage methods operated from underground workings shows promise of improving recoveries at profitable cost levels. Direct extraction of oil bearing rock by underground mining, however, still cannot be contemplated with any confidence, considering both safety and financial aspects.

Surface mining techniques offer low-cost extraction of shallow fields. Provided that the problems of separation of the hydrocarbons from the host rock and the mitigation of the environmental impacts can be solved, these methods appear capable of making a rapid contribution to the nation's oil supply at prices not too different from present levels.

One major problem encountered throughout the study was the conversion of data collected for petroleum engineering evaluation into data suitable for mining evaluation. A number of areas of data collection must be improved if the evaluation of oil reservoirs as mining prospects is to be carried out. Generally, the most basic need is in the area of estimation of mineable reserves. The true quantity and distribution of hydrocarbons in place after conventional depletion has never been established in the detail necessary for mining purposes, and a similar lack of information exists in the knowledge of physical reservoir rock properties. The major area for further work is in the processing area. Technology is now, however, being extensively developed in this area by private industry, but full-scale operations have not been conducted.

In summary, the potential is very real for the production of oil by mining methods to become a contributor to the national energy supply. It offers the possibility of recovering some of the immense resource that lies beyond the reach of existing production technology, and appears also to bring into consideration large volumes of hydrocarbons whose existence is either known or suspected, but which have never been considered as producible reserves. The potential seems too great not to be pursued further.

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Oil Shale Mining

Clifford B. Farris, Council of Energy Resource Tribes

Introduction

Shale Mining Problems

The mining problems an oil shale operator will face are largely determined by the process. Candidate oil recovery processes are surface (above ground processing of mined oil shale), modified in situ (underground with some shale removed), and true in situ (completely underground with no shale removed). The shale removed for modified in situ (MIS) is generally processed by surface techniques. The mining problems are different for each category. Fig. 1 depicts the diversity of western shale deposits.

Mining for surface operations will employ underground mining techniques in common use but the scale will be larger. A typical oil shale operation is expected to require 75,000 to 250,000 st (68 000 to 226 800 tons) a stream day of crushed oil shale. This is above the upper limit of current mining operations. Major problems include: (1) lack of good engineering design properties for oil shale, especially when interbedded with saline minerals at depths below 1,000 ft (305 m); (2) presence of water, hydrogen sulfide, and methane in some areas; (3) necessity for mine disposal of as much retorted oil shale waste as possible; and (4) control of environmental impacts of mining.

Portions of the oil shale deposits in Colorado, Wyoming, and Utah and significant portions of the Devonian shales in the eastern U.S. are adapted to surface mining. No major technological problems are apparent outside overburden thicknesses up to 1,000 ft in the West. However, numerous political and environmental difficulties have arisen. One major oil shale developer cancelled a planned surface mining operation and currently is pursuing a modified in-situ plan. The eastern shales are closer to the surface than the western, but suffer from many of the same environmental and political problems.

Modified in-situ operations face much more severe mining problems than surface efforts. Because the mined stope (called an in-situ "retort" by processors) acts as a retorting process vessel subject to gas flow, combustion, and temperatures between 1,500° and 2,000°F, mining is under highly restrictive limitations. This processing method involves removing between 20 and 40% of the shale deposit and then blasting the roof and walls into the mined space, where the oil is recovered by retorting. Major problems are: (1) swell factor severely limited; (2) need for consistent size distribution of blasted shale; (3) even filling of stope (in-situ retort) by blasted shale with consistent permeability throughout; (4) scaleup of blasting techniques, after optimization; (5) protection of retort pillars and roof during and after retorting; (6) prevention of groundwater percolation; (7)use of ANFO explosive in wet holes; (8) disposing of surface-retorted shale waste in stope; and (9) restoration of site.

True in-situ operations are less well developed than surface or MIS processes. No actual mining is done, as the true in-situ processes generate permeability in the highly

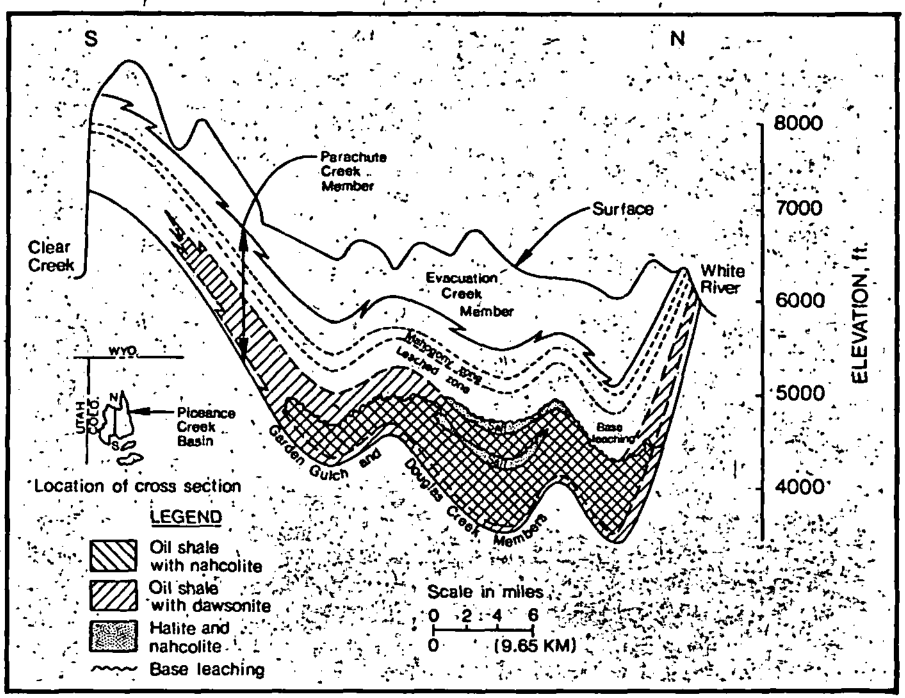

Fig. 1—Piceance Basin oil shale showing diversity of deposit.

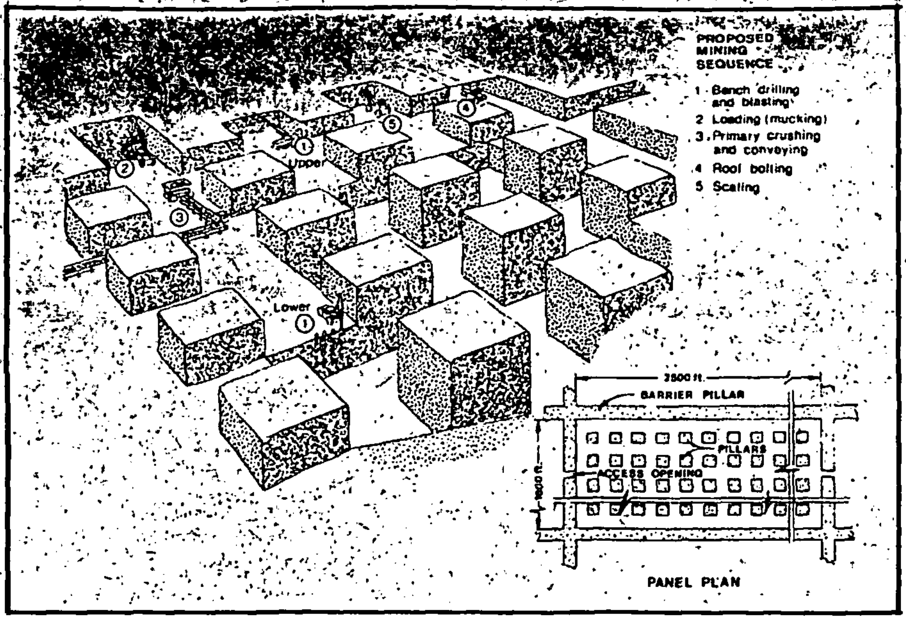

Fig. 2—Typical room-and-pillar mine.

impermeable oil shale through explosive and hydraulic fracturing or solution mining of certain soluble components. However, it is a possible alternative method to beneficiation of oil shale ore bodies in selected areas.

Current Solutions Underground

Cameron Engineers (1975) examined a number of underground mining systems for their suitability to oil shale mining. Several developers have submitted environmental impact statements or detailed development plans in which they discuss various mining methods. Promising underground methods include (1) chamber and pillar with spend shale backfill; (2) sublevel stoping with spent shale backfill, (3) sublevel stoping with full subsidence, and (4) block caving with load-haul-dump (LHD) machines. Variations of the sublevel stoping methods are required for modified in-situ methods. True in situ does not require conventional mining, though elaborate fracturing techniques are necessary.

Chamber-and-pillar (Fig. 2) was tested intensively by the U.S. Bureau of Mines between 1945 and 1956 at Anvil Points, CO, and the method is applicable to most of the deposit. Pillars 60 ft square were left 60 ft apart. Most of the equipment was specially designed, built, and tested, and much of it was later adopted by the mining industry. An electric shovel with a 3-cu yd bucket loaded the shale muck into 18-cu yd capacity trucks. Rotary drilling proved feasible. Routine mining operations did not require roof bolts, though areas in long term use such as haulage ways did. This method proved to be flexible and has been used for essentially all of the underground oil shale mining to date in the U.S. Cameron examined two variations and concluded that a system of separate chambers rather than interconnected rooms would be better adapted to spent shale backfilling due to greatly reduced need for protective bulkheads during backfilling. Resource recoveries can range from 90% near the top shale zone under a few feet of overburden and with pillar extraction, down to 35% at 3,000 ft depths.

Sublevel stoping with spent shale backfill is a productive and economical method applicable to most of the shale deposit. The method involves longhole drilling up from predeveloped sublevels from which the ore is blasted in slices and removed from drifts under the mined area. Several methods are in use. The method is highly mechanized and results in large production tonnages, but requires a heavy capital expenditure before full production is realized. Costs are low. Fig. 3 shows the arrangement of the stopes from which the blasted shale is removed. The shaded area is comprised of spent shale backfill. Design of the pillars will depend heavily on characteristics of the spent shale material, including compressibility, which are not yet fully known. About 55% of the shale can be recovered if good fill material is available. A low limit to recovery is about 35%. Surface subsidence is minimal.

Sublevel stoping with subsidence is very similar to the previous method, except that the pillars are removed after stoping operations. Ore recovery can approach 100%. However, the surface subsidence, even when used for spent shale disposal, is dangerous from the standpoint of water inflow to the operation. Environmental objections are likely.

Block caving is one of the lowest cost underground mining methods, where applicable. Much of the western oil shale is not amenable except in certain zones where leaching has occurred. Advantages include greater miner safety, lower costs, and high degrees of mechanization. Disadvantages include longer preproduction period, high drift maintenance costs, inflexible operation, and ore dilution which can approach 15%. Resource recoveries vary from 67 to 100% in current non-oil shale operations. Spent shale disposal would be possible in the surface subsidence.

Other underground methods considered and rejected early in the analysis include square-set stoping (low productivity, extremely high consumption of timber, high costs); shrinkage stoping (not readily mechanized); cut-and-fill stoping (not more expensive than sublevel stoping); longwall (needs development in oil shale); and sublevel caving (high cost for explosives and drilling supplies, ventilation problems).

The overall underground mine ranking used was a system developed by the U.S. Bureau of Solid Waste Management. A weighted ranking of these factors was developed: Technical feasibility (24%), mining cost (22%), resource recovery (20%), health and safety (16%), environmental impact (11%), and reclamation (7%). Rankings from the most desirable to the least were:

Underground Process	Relative Mining Cost
Chamber and pillar	1.00
Sublevel stoping with spent shale backfill	1.08
Sublevel stoping with full subsidence	1.11
Block caving using LHDs	1.27
Block caving using slushers	1.31
Advance entry and pillar	1.23

Other mining methods ranked below these for many reasons.

Current Solutions – Modified In Situ

Modified in-situ mining operations are still in a state of active research and no final designs have been selected. However, Fig. 4 shows a sublevel stoping operation in oil shale. Conceptually, the modified in-situ operations resemble one of the above stoping operations where the rock is blasted but not removed from the stope during production. Preproduction operations involve mining between 20 and 40% of the shale, leaving a void into which the remainder of the shale is blasted. One operator contemplates a vertical orientation and commercial retorts about 120 ft square and about 250 ft high, and a void fraction of approximately 20%. Another operator is contemplating retorts in the size of 150 × 300 ft in cross section by 700 ft high. A sublevel caving modification is planned with higher void fractions being considered.

Current Solutions – True In Situ

Voids and permeability are introduced into the shale by explosive or hydraulic fracturing rather than direct mining. As such, it is not a mining method, though it is an alternative. This work is still under active research, and is less well developed than other mining methods.

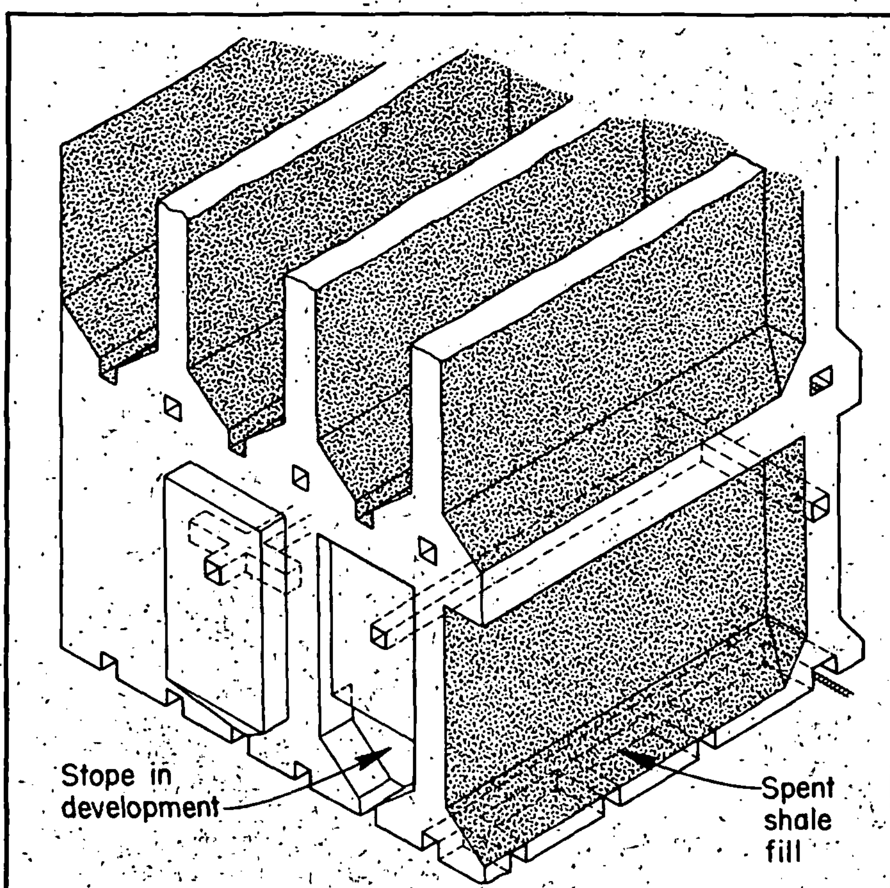

Fig. 3—Possible sublevel stoping mine (after Cameron, 1975).

Major Mining Projects

A number of oil shale projects currently are planned or are in various stages of research. Mining techniques planned for the major projects are summarized here.

Colony

Production of about 61,000 stpd is planned from a conventional room-and-pillar mine. About 60% of the shale in place will be extracted. The mined section averages about 35 gal of oil per st and will be about 60 ft thick. Mine access will be from a portal bench constructed in the canyon of the Middle Fork of Parachute Creek at the level of the Mahogany zone outcrop. Mining will proceed by the conventional cycle of drilling, charging, blasting, wetting of rock piles, loading, hauling, scaling, and roof bolting (Fig. 2).

Dow

This research is concentrated in the Antrim shales of Michigan, part of the Devonian shales in the eastern U.S. The method is a true in situ. Research supported by Dow produced some rubblization and rock fracturing by thermal stress during combustion. Current work is attempting to generate more extensive rubblization by fracturing. Process steps are (1) hydraulic fracture of the beds, (2) chemical underreaming followed by explosive fracturing, and (3) explosive underreaming followed by explosive rubblization and fracturing. Hydraulic fracturing is maintained by sand propping after being formed by hydrochloric acid acting on soluble limestone stringers. This is followed by retorting.

Equity

This process also is a true in situ. However, it is confined to the leached portion of the deposit where adequate permeability exists due to natural leaching of minerals. This process is still in active development and no final designs have been published.

Geokinetics

Deposits relatively near the surface are the target of this true in-situ process. A volume of oil shale is drilled and blasted to form a well-

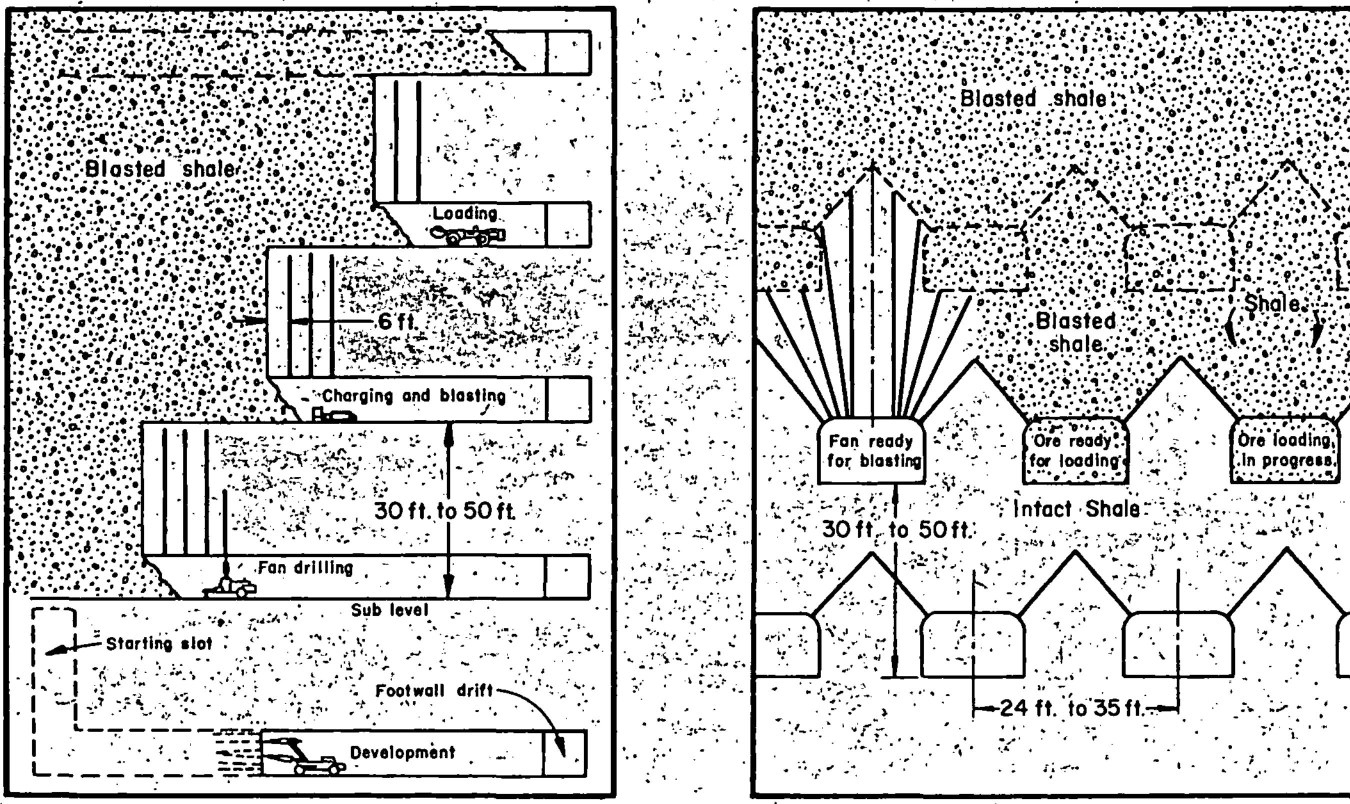

Fig. 4—Sublevel caving mine in oil shale. Left, side view of a typical sublevel caving operation (Haycocks, 1973); right, cross section of a typical sublevel caving operation (Haycocks, 1973).

fragmented mass of oil shale sealed by an impermeable zone above. The surface of the ground is raised from 6 to 12 in. to generate the void space in the shale. Other applications may be modified in-situ operations in thinner oil shale beds, secondary recovery of pillars in mines, and mining of floors and roofs in oil shale mines. Ultimate size of the retorts in shale beds is up to 30 ft thick and 200 ft square. Blasting of the shale while leaving an impermeable cap has been successful, as has been subsequent retorting.

Inst. of Gas Technology

Mining research is not directly being conducted here but the process under study is applicable to eastern oil shales. These shales are amenable to either surface mining or thin bed in-situ techniques.

Multi-Mineral Corp.

A mining research program based on access from the existing 8-ft-diam. and 2,352 ft-deep USBM shaft at Horse Draw, CO, is planned. The conceptual retorting operation will involve mining shale from large stopes, crushing it to liberate nahcolite which will be recovered, and replacement of the crushed shale in the stope for retorting. The research program is oriented to obtaining geotechnical data to support the commercial plan and feasibility study. This two-phase effort is illustrated in Fig. 5. A total of 15,000 st of material will be produced for processing, research and evaluation. Phase I is the upper working and will generate rock mechanics design data and required tonnage (5,100 st) of nahcolite-rich bulk sample. Phase II is excavation of a stope block to study blasting, pillar design, and rock stability in high-wall openings. Concerns are rock jointing systems; rock temperature gradient; character of methane gas occurrence; aquifer horizons, etc.; rock formation behavior; methods of blasting; fragmentation characteristics of mixed nahcolite, dawsonite, and oil shale; blasting effects and behavior on high-wall opening; and selection of operating methods. The experimental stope will be approximately 64 × 40 × 110 ft.

Occidental

A vertical modified in-situ (VMIS) process will be employed. Initial operations involve mining approximately 20 to 25% of the shale from upper and/or lower levels of the desired stope (retort). It is preferable to mine out lower grade areas if they are available. Longhole drilling from the mined out space into the oil shale is followed by loading and blasting with mixtures of ammonium nitrate/fuel oil (ANFO). The detonation is staged carefully with time delays so that broken shale will fill both the volume of the mined-out space and volume of shale column. Furthermore, appropriate delays are necessary to obtain proper shale particle size.

Variables of importance are (1) explosive parameters, explosives, and detonation systems; (2) effects of geology on fragmentation; (3) explosive patterns, spacing, hole size, timing, etc.; (4) mined void volume geometry; (5) orientation of retort to geologic conditions; (6) effect of retort size; (7) evaluation of seismic effects; (8) measurement and control of air blasts; (9)

protection of sensitive equipment and nearby facilities; (10) reentry; (11) bulking full; (12) scaleup; (13) use of ANFO in wet holes; (14) up-hole loading systems; and (15) protection of surrounding pillars, roof, and boundary pillars. Commercial retorts will be approximately 200 ft square by 310 ft high. They will be grouped in clusters of eight, with 32 clusters assembled into a panel. A panel will support production of 57,000 BOPD for perhaps 4 years.

Paraho

This operation, supported by a consortium of companies, is developing a retorting process suitable to a wide range of oil shale. A unique mining plan is not applicable. Some mining research is being conducted by DOE at the adjacent Anvil Points mine, which was originally opened and studied by USBM in the 1940's. The present operations feed a 400-stpd semiworks plant on the site.

Rio Blanco

This project on lease C-a in Colorado contemplates a combination of modified in-situ and surface processing of oil shale. Original plans were to use open pit as the overburden ranges from 60 ft to about 400 ft. However, as off-site waste disposal was not available, a decision was made in 1976 to employ modified in situ. Development will consist of sublevel caving methods in combination with technology similar to recovery of heavy oil in conventional oil fields. It is planned to fill the burned out retorts with slurried waste shale from the surface retorting operation to eliminate subsidence and possible percolation of groundwater through the retorted shale. Commercial production in the late 1980's will require daily mining of 40,000 st of shale for surface plant and rubblizing of another 134,000 st underground. As mining will produce more water than the process requires, the excess will be reinjected off-tract into the basin's aquifers where it originated.

Mining stages include shaft sinking (well underway at this time), station and level development, development of combustion air and product separator systems, underground haulage, primary crushing, hoisting, surface haulage, mine draining, and mine ventilation. Shaft sinking operations have encountered groundwater and hydrogen sulfide as well as small amounts of methane which are well below original expectations. Hydrogen sulfide is dissolved in the water and has become a much less severe problem as mining operations have proceeded. Ventilation has been able to control the gases to the point the mine will be classified nongassy.

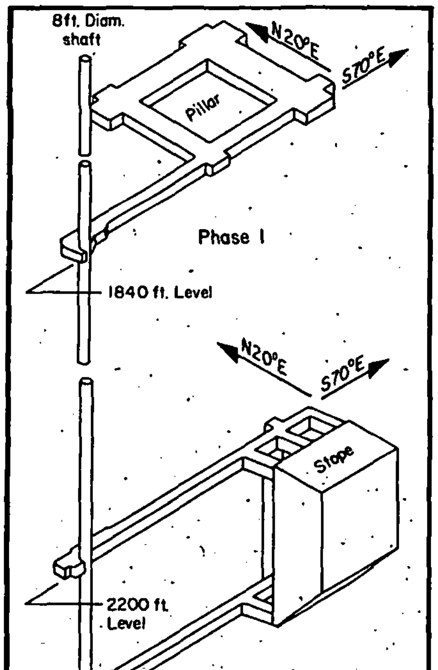

Fig. 5—Multi-Mineral Corp. experimental mine.

Superior Oil

A relatively conventional room and pillar arrangement will be used. An unusual feature is the three 11,600-ft adits following the shale outcrop downdip to the mine. Adit 1 will contain an aerial tram for personnel and materials. Adit 2 will contain two 36-in. conveyors, and Adit 3 will be for ventilation. An exhaust shaft will be drilled into Adit 3 and an emergency access shaft drilled into the southernmost (most remote from portal) end of the mine. It will extend from the surface down 2,500 ft into the lowermost mining zone. Mining will occur in three levels. The lower zone contains nahcolite-rich shale, the middle zone is dawsonitic, and the upper contains all three in mineable quantities. Production among the zones will be varied in response to market demand for the respective products. Development will be by superimposed panels following the natural bed inclination of about 14 degrees. These panels will be room-and-pillar of about 100 acres in size separated by 100-ft barriers. Distances between pillars will be between 45 and 60 ft. Should unexpected conditions occur such as structural failure or excessive water, a panel can be sealed with no disruption of work at adjacent panels. Panel mining also will allow concurrent mine backfilling with spent shale slurry and mining operations. Initial production will be from the lowest level at a daily rate of 9400 st. Later, full scale operation of all levels will see total mine production of 26,000 stpd.

Taley-Frac

A true in-situ operation is employed which generates permeability with high pressure water. A slurry explosive is pumped into the fracture system and detonated, and retorting follows.

Union

Plans are to use a conventional room and pillar mining operation which will feed a surface retorting plant. A mine portal will open onto the bench and provide access to the mine. Mine production will be trucked to an underground, two-stage, crushing-screening plant. It is expected that a 60-ft seam of mahogany shale with a Fischer assay of 34 gal/st will be mined.

White River Project

This operation on federal lease tracts U-a and U-b in Utah will combine room-and-pillar mining with modified in-situ as a secondary method. At present, the operation is stymied by a lawsuit over ownership of the land.

Oil Shale Mining Research

Most of the government oil shale mining research is sponsored by the DOE after moving there from the USBM and other agencies in 1977. The USBM currently is not sponsoring direct mining research for oil shale, but is involved in environmental research pertinent to oil shale. The EPA is sponsoring mining and extraction studies. A brief summary of these three programs follows.

Dept. of Energy

The "Draft Program Management Plan," dated June 25, 1979, gives an overview of the DOE program with a focus on in-situ technology. DOE hopes to develop by 1982 at least one design for a commercial size process using the modified in-situ method. Present mining technology appears capable of supporting commercial operations under today's economic conditions. However, modified in-situ technology is less well developed. The DOE plan addresses (1) mine planning, (2) access and site preparation, (3) mining for in-situ retorting, (4) mining for surface retorting, and (5) haulage.

"Mine Planning" will develop planning tools including economic models, equipment selection, criteria, mining simulation models, etc., to yield an optimum mining system. Methods for analytic modeling and optimization have been and are being developed, often by analogy with other mineral resource practice. Preliminary model development and plans are scheduled for completion by 1982. Optimal plans call for vertical modified in situ by 1986 and for surface process mining plans by 1989.

"Access and Site Preparation" research will develop site preparation plans and methods for all types of oil shale mines. Further objectives include development of a rapid and cost effective method of accessing specific shale production areas and mine designs. Drill-blast-muck methods presently are used in construction of large-diameter shafts to underground mines. Rotary drilling systems powered from the surface are being investigated with diameters up to 15 ft. Small diameter (1 to 12 ft) shaft sinking systems that can sink shafts at the rate of 50 ft per 24-hr day are ultimately needed. A current project is testing a 20-ft-diameter drill to depths of 2,000 ft. It is expected that large diameter (12 to 40 ft) systems that can sink shafts at 30 ft per day will result from this program. Raise boring techniques for shafts to 20-ft-diameter are currently used when access to the bottom of the shaft is available. DOE also is sponsoring development of a downhole powered (blind shaft boring) drill to bore shafts up to 24-ft-diameter at depths up to 2,000 ft.

"Mining for In-Situ Retorting" is directed toward shale preparation prior to retorting underground. True in-situ methods do not involve material removal, but these methods are not yet well developed. Modified in situ requires mining of 20 to 40% of the shale and rubblization of the remainder. Developers are concentrating on obtaining requisite permeability, particle size distribution, and void characteristics. Other programs include development of computational models for the explosive rubblization effects, mining and haulage methods for required acccess and excavation of retort areas, validation of ground control techniques on a large scale, and full analysis of ventilation systems. Though this technology still is developing, it is trailed by less studied and understood methods for evaluation and diagnosis of the process and reliable design methods. Also unproven are demobilization procedures after retorting, and values for shale physical and thermal properties under in-situ mining and retorting conditions. Economics are very uncertain at this time.

"Mining for Surface Retorting" is directed toward high-volume, cost-effective mining methods for extracting oil shale for surface retorting. Drill-blast-muck methods currently employed in hardrock mining generally can be used, and are operating at rates in the range of 60,000 stpd which could supply a 30,000 B/D plant. This is on the small side for projected oil shale operations. Enhancements to technology up to 100,000 stpd underground mining and 250,000 stpd surface mining are desirable. A total mining complex at the level of 700 to 2,000 million stpy may ultimately be required to support a 1 to 3 million B/D shale oil industry. This portion of the program is to develop commercial mining requirements, formulate an appropriate R&D program, and design preliminary and optimal mine plans.

"Haulage" for men and materials is under study. The largest hard rock underground operations currently mine and transport up to about 70,000 stpd. The largest surface mine is about 200,000 stpd. Mine haulage systems do not exist to support more than one large shale plant. Areas under research include rapid, safe, and economical transport of men and supplies to all work sections of a large mine in under 30 minutes; efficient and economical face haulage systems; and total haulage systems integrated into the overall operation. Design of haulage and models, as well as associated cost models, is scheduled for completion by 1980. Actual development is set for 1983. Field tests of full-scale systems are scheduled for 1986 (modified in situ) and 1989 (surface).

Bureau of Mines

Most of the programs from USBM were transferred to DOE if they related to oil shale mining. The Bureau, however, is conducting research into in-mine disposal of retorted shale and various waste disposal problems. Much mine technology research for other types of mines will be readily applicable to oil shale deposits as well.

Environmental Protection Agency

The mining-related work is being done under the Extraction and Handling Div. Objectives are related to definition of environmentally acceptable practices for oil shale mining. It is felt that restoration of the semiarid oil shale areas of the West will be extremely difficult. Mines in the East are felt to be more reclaimable. Projects are underway on the nature, quantities, and composition of fugitive dust emissions near mining operations, haulage roads, crushing operation. and spent shale transfer points. A field project is underway in the Anvil Points, CO, area.

Other Research

Much research is being conducted by the oil shale developers, equipment manufacturers, and others closely tied to the oil shale industry. However, these results are generally proprietary or not finalized in a form for publishing.

Conclusions

Underground oil shale mining appears fully feasible with current mining technology, though the maximum scale of oil shale will push the limits a bit. Better design data for the rock is desirable and is being developed. Modified in-situ mining and rubblization is rather difficult from the mining standpoint as the stope will be used as a retorting vessel. Many problems related to blasting in limited spaces to generate a carefully-sized shale rubble of even permeability are now under development. No commercial operation is yet proven. True in situ is less well developed than modified in situ and involves access to the shale by generation of artificial fractures or use of existing permeability in the limited zones where it exists. Much research is underway. Again, no commercial operations are proven.

Clifford B. Farris is affiliated with the Council of Energy Resource Tribes. This paper was written while he was a senior project engineer with the Colorado School of Mines Research Institute. There, he was in the Energy Division where he specialized in oil shale research, oil shale related minerals, and energy modelling. Earlier positions included assistant to the vice president, Tucson Gas and Electric, in charge of an SNG plant, and various other positions within the energy industry. He has an undergraduate and a Master of Science degree from the Colorado School of Mines.

National Underground Coal Conversion Program Overview

Cyril W. Draffin, U.S. DOE

Introduction

Americans have long been proud of their ability to recognize a need, define it, and then develop workable solutions. The U.S. underground coal conversion (UCC) program is a good example. In 1974, the need to utilize coal resources that could not be mined was recognized, and Congress gave the Bureau of Mines $1.7 million to gain a better understanding of the UCC technology and its potential applications. Since 1977 when the U.S. Dept. of Energy (DOE) was formed, workable technologies have been tested, the market for underground coal conversion has been recognized, and extensive industrial interest has developed.

Perspective

The U.S. is blessed with extensive coal resources. Coal supplies about 19% of our national energy needs, yet recently promulgated environmental standards and increasing mining costs have limited direct coal use. UCC potentially can use coal that is economically or technically infeasible to mine because the coal is too thick, deep, dirty, high-ash, and wet; has an excessive angle of dip; or has unpredictable and poor overburden characteristics that make mining unsafe. Coal can be gasified underground or perhaps liquefied below the earth's surface.

Underground coal gasification (UCG) is the prime element of the underground coal conversion program. It enables coal to be converted to gas underground.

UCC Coal Resource

Recent data show a total U.S. coal resource base of about 6.4 trillion tons. Of this, 1.8 trillion tons might be accessed by UCC, including some minable coal. A commercial UCC process could quadruple roughly the 450 billion tons of U.S. coal reserves, which presently are recoverable by mining.

The U.S. coal resources are divided into five sectors. The two most eastern sectors contain relatively thin, swelling bituminous coals that are difficult to gasify. Of the two, the bituminous coal in the Eastern Province is the most difficult because it is deeper than in the Interior Province and the terrain is more rugged.

The sector along the Rocky Mountains contains huge amounts of thick low-rank coals that are the most promising for early development by UCC. The coal has good continuity and the terrain is suitable. Low-rank coals such as subbituminous and lignite are highly reactive and tend to shrink and disaggregate when heated. Most of the coal in the Pacific sector is in the state of Washington. These coals tend to be highly fractured and faulted; much of the coal is steeply dipping. Abundant coal, much of it low-rank, is also found in Alaska; however, Alaska's distance from markets in the lower 48 states will tend to limit UCC to local markets.

An attractive aspect of UCC is that only a limited surface area is needed for commercial development of the thick seams of low-rank coal found in the western states. For example, the total amount of coal needed for a 250 million scf/D plant producing synthetic natural gas (SNG) for a 20-year operating life is 160 to 200 million tons, depending upon heating value of the coal. Using a coal thickness of 30 ft, 1 acre contains a reserve of 53,000 tons, and a square mile encloses 34 million tons of coal. Thus, during the lifetime of even such a large plant, operations would encompass less than 6 sq mi.

Advantages and Disadvantages of UCG

Some potential advantages, especially important when compared with conventional coal mining combined with surface gasification, have not been proved, but DOE's program is designed to show that UCG can: (1) use large coal reserves not economically recoverable by conventional mining methods to allow electric utilities to switch from natural gas to a coal-derived fuel: (2) minimize health and safety problems associated with conventional coal extraction techniques; (3) produce less surface disruption and bring less solid waste to the surface; (4) consume less water and generate less atmospheric pollution; and (5) reduce capital investment and gas costs by at least 25% compared with surface coal gasification.

UCG also has some potential disadvantages: (1) UCG requires processing at the site of the coal deposit; (2) ground subsidence could cause gas leakage or damage to surface equipment; (3) UCG might cause disruption of aquifers and pollution of groundwater; and (4) low heating value gas (from air injection) is uneconomical to transport over long distances (markets for this gas must be near the plant site).

Comparison of these advantages and disadvantages indicates that UCG offers great promise in specific areas of the country.

UCC Technology

Although underground coal liquefaction processes are under consideration, the major UCC technology in the current program is underground coal gasification. Underground coal gasification has existed as a concept since 1868 and field tests have been conducted since 1912. The Soviets have conducted a field program for 40 years and have operated semicommercial UCG plants for 20 years. The Soviet work proved that underground coal gasification is feasible technically because they were able to maintain reasonably stable heating values and production rates of gas over a period of several years.

Technology involved in gasifying coal underground is straightforward, but it is not easy. Coal is gasified by drilling into the coal seam and injecting air (or oxygen and steam) into the underground reaction zone. The coal is partially oxidized, producing low- or medium-Btu gas. The hot gas is forced through the seam to the exit boreholes and is carried to the surface where it is cleaned and upgraded for use.

The natural permeability of a coal seam is too low to sustain the high gas flow rates required for gasification. Thus, a critical part of the technology is the creation of permeable pathways, or links, in the coal seam between the injection and production boreholes. These links can be created by reverse combustion, directional drilling, or other techniques. For low-rank coals (subbituminous and lignite) that shrink and disaggregate upon heating, it is particularly important and effective to produce the links near the bottom of the coal seam. Coal immediately above the gasification zone disaggregates upon heating and, in effect, creates an underground packed bed of coal.

The gasification zone expands from the bottom to the top of the seam, utilizing all the coal. If a linkage channel is formed at the top of the seam, a much smaller portion of the coal is gasified; in addition, the injected air tends to bypass the gasification zone, causing production of very low-quality gas. Thus, the existence of a linkage channel low in the seam ensures that the coal and air are reacted effectively, and that the product gas has a high heating value that remains fairly uniform with time.

During the past few years a number of key technical achievements have occurred, including the following:

1. Air injection produced low heating value gas (approximately 160 Btu/scf) at an average of 7 million scf/D during a 55-day experiment conducted by the Laramie Energy Technology Center.
2. Steam/oxygen injection produced medium heating value gas (263 Btu/scf) at 3,300,000 scf/D during a 2-day oxygen test in the midst of a 58-day air experiment conducted by Lawrence Livermore Laboratory.

Market for UCG

Either low- or medium-Btu gas is generated, depending on whether air or oxygen is injected. If air is used, low-Btu gas (100 to 200 Btu/scf) is produced. This low-Btu gas can be used for electric power generation and process fuel near the coal deposits. If oxygen is used, medium-Btu gas (250 to 300 Btu/scf) is generated. Medium-Btu gas can be used as a feedstock for production of ammonia, methanol, or gasoline; for power generation and process fuel within 200 mi of the site; or upgrading into high-Btu gas (SNG) for injection to the national pipeline grid.

Lignite and subbituminous coal are easier to gasify underground than bituminous coal or anthracite; consequently, UCG will be used first in lignite and subbituminous resources. Fortunately, there are large markets for electric power, SNG, chemical feedstocks, and industrial energy in the same regions where subbituminous coal and lignite are located. Table 1 indicates the markets for UCG in the states of Texas, Louisiana, Washington, Wyoming, Arizona, New Mexico,

TABLE 1 – PRIMARY NEAR-TERM UCC MARKETS

Location	Application	Approximate Local Lignite or Subbituminous Coal Resources (billion tons)
Gulf Coast	Electric power Chemical feedstocks Industrial energy	50
Washington State	Electric power	1.5
Rocky Mountain	Electric power SNG	120
Four Corners	Electric power SNG	70

Utah, and Colorado that could be tapped by the year 2000. These eight states annually consume about 200,000 MW of electric energy and 6×10^{15} Btu of natural gas for chemical feedstocks, residential/commercial applications, or industrial process energy. These states also contain 240 billion tons ($4,800 \times 10^{15}$ Btu) of lignite and subbituminous coal.

Industrial Interest in UCG

Extensive industrial interest in UCG has grown in the past year. Table 2 lists the key U.S. companies that have expressed publicly active interest in UCG.

In the private sector, Basic Resources Inc., a subsidiary of Texas Utilities Services Inc., has licensed the Soviet technology and is developing underground gasification of Texas lignites near Fairfield, TX. They have completed two tests and plan to build two or more 200-MW electrical power plants using UCG in the 1980's. Atlantic Richfield Co. has executed a successful field gasification test in a 100-ft thick subbituminous coal seam near Reno Junction, WY. Texas A&M U. is carrying out UCG tests in lignite under sponsorship of a consortium of private companies.

Current Technology Issues

Results of the program to date indicate that while UCG is feasible technically, it still contains some process uncertainties that must be resolved further before UCG can be used commercially: (1) demonstration of reliable, cost-effective linking near the bottom of the coal seam; (2) determination of process efficiencies (thermal and oxygen utilization efficiencies) with steam/oxygen or air injection; (3) determination of sweep efficiencies (resource extraction) with steam/oxygen or air injection in multiwell systems; (4) ability to operate multiple modules; (5) capability for scaling up the UCG process to economic commercial size; (6) development of process control techniques to achieve reliable product gas composition and flow rates and economic instrumentation to monitor remote processes; (7) ability to predict performance at new sites based on reliable data and process models; (8) control of water influx to the reaction zone; (9) evaluation of coal seam limitations, including thickness, depth, rank, shale stringer, dip, permeability, hydrology, continuity, overburden, and floor rock characteristics; (10) development of definitive cost estimates and detailed economic comparisons with alternative energy extraction techniques; (11) determination of optimum well spacings with respect to linking methods and resource extraction efficiency; (12) ability to develop a cost-effective UCG system to gasify bituminous coal; and (13) control of gas losses from the underground gasifier.

Further research and work is necessary to reduce environmental uncertainties of UCG operations. The major environmental uncertainties associated with UCG include subsidence causing aquifer disruption of interconnections that affect flow patterns and rates; water quality effects caused by contamination of ground water; surface disruption caused by site activities and subsidence; gas leaks to the surface; and the amount, quality, and sources of water required for the process.

The Future

The highest priority of the UCC program is to develop and demonstrate, in conjunction with industry, a commercially feasible UCG process during 1985-87. To do this, the program must concentrate on the coal resource that shows the most potential at the present time – low-rank coal. In order to address the major potential markets for UCG, both air gasification and steam/oxygen gasification will be pursued. Considering the prospective industrial involvement in the program, this suggests the need for two parallel projects. Low-Btu gas is of interest primarily to electric utilities, while medium-Btu gas is required by oil, gas, and chemical companies interested in SNG or chemicals. The second priority for the UCC program is to develop technology for near-market bituminous and steeply dipping coals.

TABLE 2 – INDUSTRIAL INVOLVEMENT IN UCG

Institution	Activity
Atlantic Richfield Co.	Privately funded UCG field test
Texas Utilities Services Inc.	Privately funded UCG field tests using Soviet technology
Public Service Co. of New Mexico and U. of New Mexico	Proposed 50% funding of UCG field test
Williams Brothers Inc.	Consortium of 10 interested companies
Texas A&M	Privately funded UCG field test
Gas Research Inst.	Cost-sharing DOE's western medium-Btu-gas project

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Innovative Coal Extraction Technology

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Introduction

Although innovative coal extraction technology can be approached from many angles, this paper focuses on three: innovation in response to rising costs, to changing mining conditions, and to regulatory issues. Before exploring these three subjects, however, a basic question needs to be raised.

Why Innovation?

Coal is widely heralded, and quite correctly so, as the United States' "ace in the hole." It has been said that the U.S. is to coal what the Arabs are to oil. The implication is that we have nearly inexhaustible reserves—that coal is cheap, plentiful, and easy to extract. Indeed, because our current productive capacity is estimated to be 15-20% greater than demand, we have been given a false sense of security about the ease of future coal extraction. Therefore, innovative measures are being concentrated on developing technologies for the demand side of coal, including power generation, synthetic fuels, and industrial applications.

What is often forgotten is that the unit cost of producing energy from these new technologies depends critically on the cost of the coal feedstock—in some cases the coal consumed accounts for more than one-third the total cost. Thus, while the developers of the end-use technologies struggle to improve the overall thermal efficiency of their process by one or two percentage points to make the energy produced competitive in the marketplace, they often are unaware of the risk of a 3 to 6% increase in coal costs wiping out the expensive, hard-earned results of their research.

Energy planners are just beginning to realize that coal is not a uniform commodity available at low cost in infinite quantities. Coal is a heterogeneous material whose cost and quality vary widely with local conditions. To produce the massive amounts of projected coal-based energy at reasonable costs, we urgently need developments in extraction technology, as well as in end-use technology. Thus, coal extraction, coal conversion and utilization, and end-use energy consumption must be viewed as highly interdependent parts of an energy supply network (Fig. 1). And current emphasis on conversion and utilization must be balanced by more emphasis on upstream technologies, including coal extraction. Even more important, the impacts of innovation (or the lack thereof) in any one technology area in the energy supply network need to be discussed and understood by those working in each of the other areas.

Why innovation in coal extraction technology? Figuratively, we are all in the "coal boat" together—geologists, miners, transporters, processors, power producers, distributors, and consumers. Innovation is required from each of these sectors to overcome the obstacles that prevent greater use of our most abundant national energy resource. All other links in the coal energy supply network depend on large volumes of coal produced at reasonable costs. Declines in productivity, therefore, must be reversed; the more difficult mining conditions that will be encountered call for new methods and equipment; and regulatory issues must be resolved if the coal extraction link is to be a strength rather than a weakness in the planned U.S. transition to an economy based more on coal and less on imported petroleum.

Innovation Tailored to Regional Conditions

Once the importance and urgency of innovative coal extraction technology has been grasped, the next step—implementing a research program—becomes quite

ENERGY SUPPLY NETWORK

Resource →	Extract Raw Material →	Pre-Process Raw Material →	Transport Pre-Processed Material →	Transform Pre-Processed Material →	Distribute Transformed Material →	User
Fossil Source	Example Energy Supply Facilities					Forms at End Use
Coal Oil Gas Oil shale Tar sand	Surface mine Underground mine Onshore well Offshore well	Preparation plant Prerefining Storage Load out	Railroads Pipelines Waterways Trucks	Power plant Petroleum refinery Gasification plant Liquefaction plant MHD	Electrical grids Pipelines Railroads Trucks	Electricity Gas Fuel oil Gasoline

Definition of Energy Supply Systems Terminology:

1. *Energy Supply Network:* Pathway or chain of facilities that connect an energy resource to an energy user.
2. *Energy Supply Facility:* A major, self-contained link in an energy supply network that is designed to extract, pre-process, transport, transform, or distribute energy resources. The design objective of such a facility is achieved by a combination of unit operations.
3. *Energy Supply Unit Operation:* A major subsystem that accomplishes or supports one of the steps in the overall process of an energy supply facility.
4. *Energy Supply Component:* A small part or element that forms a part of an energy supply unit operation.

Fig. 1—Coal extraction is a key link in delivering coal-based energy to the consuming public.

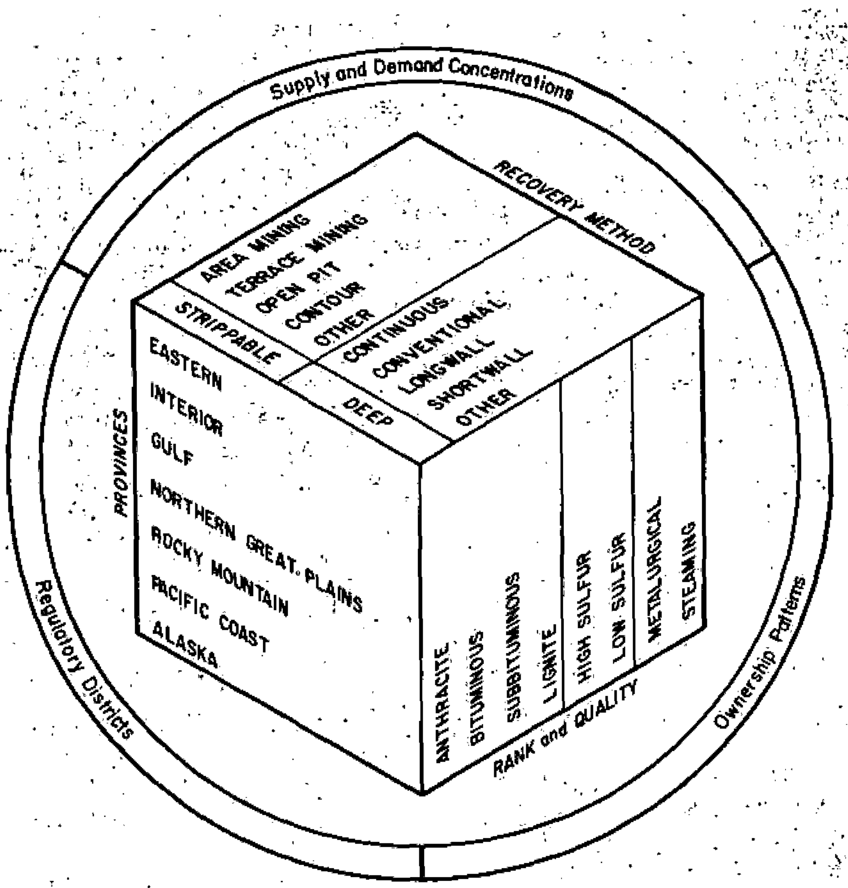

Fig. 2—Coal reserves and mining problems can be divided into many subcategories.

complex because coal deposits themselves are diverse and complex. The factors that influence productivity and extraction costs vary from location to location; problems posed by new deposits bear little relationship to one another from one region to another; and regulatory issues that preclude the development of some deposits are easily resolved for others.

The point here is that no single innovation in coal extraction technology will apply across the board to the U.S. reserve base. Therefore, to implement a program of research, whether at a manufacturer's laboratory, a university, or a government agency, the priorities set must account for regional variations. Innovation must be tailored to regional conditions, with emphasis on extraction technologies that are potentially applicable to exploiting large regional reserves at competitive costs.

Thus, as a first step, the coal reserve base must be subdivided to establish research goals and priorities for each category. Several equally valid methods exist for performing this subdivision (Fig. 2). These approaches are useful for identifying the geographic distribution of probable future coal production and for ascertaining the geographic distribution within those production areas of coal extraction problems amenable to innovative technology. By such disaggregation, research objectives can be tailored to region-specific problems. And priorities in funding can be set on the basis of a company's product line, a university's constituency, or a government agency's responsibility in carrying out its national mandate. (In all cases, the eventual number of buyers or users of the technology will have a bearing on how much funding is justified.)

Such disaggregation is easier to describe, however, than to achieve. Forecasting regional demand and production is subject to much uncertainty; moreover, regional resource data are incomplete. Nevertheless, we should attempt to identify and rank needs of specific areas that must be solved by coal extraction technology, whether they entail mountain-top removal mining in Appalachia; extraction of deep, thick seams in the Rocky Mountains; longwall mining in the Midwest; extraction of tilted beds in the Pacific Northwest; stripping of multiple seams in Wyoming; mining of anthracite in Pennsylvania or Rhode Island; mining of lignite in the Northern Plains of the Gulf Coast; or the hundreds of other mining problems that apply to regional and subregional geographic areas such as those shown in Fig. 3.

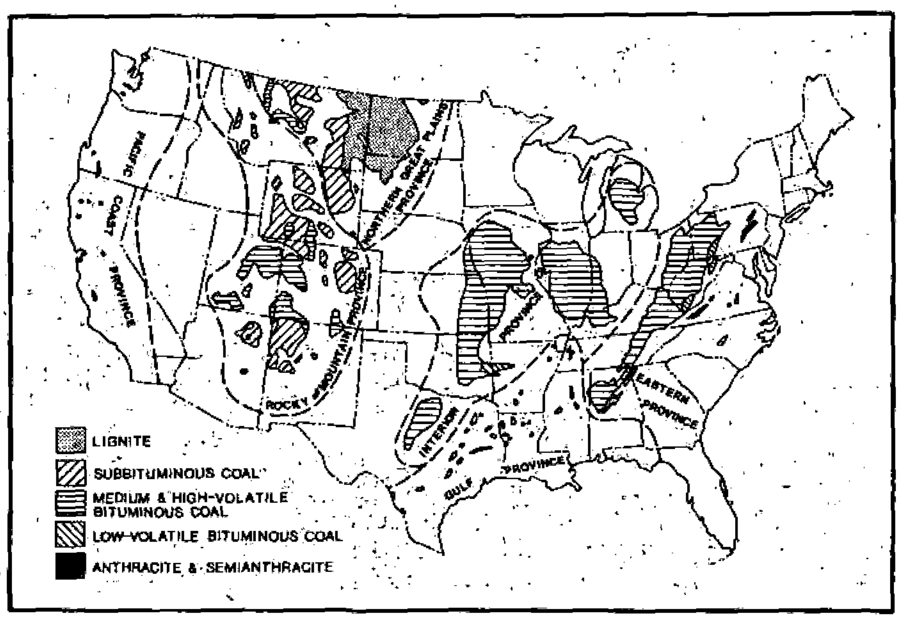

Fig. 3—Research priorities must be tailored to regional conditions.

Innovation to Control Costs and Improve Productivity

In recent years research in coal extraction technology has concentrated on production problems. Five areas of work have potential for helping to control costs and improve productivity: (1) mine planning technology, (2) mine development technology, (3) improved unit operations, (4) improved components, and (5) innovative mining systems.

Mine Planning

Mine planning technology has progressed greatly in the field of computer applications. Computer programs are available for geologic modeling, geostatistical interpretation, feasibility studies, simulation of unit operations, design of surface and underground workings, equipment selection alternatives, productivity analysis, cost evaluation, production planning, and production data gathering. These programs provide a sound base of information to assure that the major investment required to open a large new mine can be made with less risk. The programs now available are good, and they are being improved by adding necessary detail. However, there is one note of caution: no substitute has yet been found for gathering field data in the appropriate detail as input for the analysis requires, nor is there substitute for experience in interpreting results and assuming responsibility for decisions.

Mine Development

Mine development technology also is progressing. Exploration methods are improving through cheaper, faster drilling and through the use of seismological methods to supplement drilling. For underground mining, field demonstrations are under way to test new approaches in rapid shaft sinking and main heading development. These approaches may reduce the lead time necessary for opening a mine and preparing for the exploitation of deposits deeper than those currently mined.

Unit Operations

Improving unit operations has received considerable emphasis over the years, as witnessed by the successful introduction of the continuous miner, roof bolting, and large-scale draglines. For underground mining, current research is focusing on combining extraction and roof support in a single machine so that longer continuous and more productive advances can be made without machine place changes. All four major manufacturers of continuous miners are involved in developing such a machine, and all four face two similar problems: (1) how to package and operate a complex combination of machinery in a physically restricted space, and (2) how to assure reliability and maintenance characteristics as good or better than the individual machines being replaced. Eventually, with perseverance and innovation in cutter design, roof drilling systems, roof bolt design, automated and sequenced controls, temporary roof supports, and integrated face ventilation, we can expect improvements in room-and-pillar mining. These improvements will be aided by advances in face haulage technology that employ improved shuttle cars, self-advancing belt systems, and hydraulic transport. New methods of removing or partially extracting pillars during retreat mining also are being developed. Room-and-pillar mining research is attempting to solve the productivity and cost bottlenecks currently experienced in existing mines.

For such new technologies to be successful, it is increasingly necessary to test machines and components on the surface so that a mechanical shakedown of the equipment is completed before going underground. Going underground with equipment too soon or raising expectations with overly optimistic forecasts of performance has resulted in many promising developments ending up in a rusting pile outside the portal.

Even as improvements do evolve in room-and-pillar mining, an eventual limit will be reached in regard to how deep these methods can be used; eventually, new methods such as longwall mining must be adapted to U.S. conditions. Longwall mining that employed European technology began penetrating American markets in the 1950's. However, differing mining conditions here have limited the application of longwall units, primarily because of roof support problems. The new longwall shields recently introduced in Europe and the U.S. appear to be an effective solution and have reawakened interest in higher capacity cutting, higher capacity face and section conveyors, and some forms of automation. Still neglected, however, are the improvements needed in driving development headings (which can account for as much as one-third of the coal produced, even in a mine with all longwall sections), roof control in head gates and tail gates, and ventilation of working faces and gob areas.

Improved unit operations in surface mining have concentrated on overburden handling, with attention focused on continuous haulage of overburden. Thus far, research has largely consisted of conceptual studies of various schemes of overburden blasting, extraction, in-pit crushing, movable conveyors, and spoil stacking. Some schemes are designed for contours and ridges in Appalachia, others for Midwestern strip mining, and others for open-pit terrace mining. All these applications suffer from three major problems: (1) most overburden overlying U.S. coal seams is sufficiently consolidated that continuous extraction by bucket wheel, like that practiced in Europe, is impracticable; (2) seams are so thin that the design and operation of shiftable in-pit crushers and conveyors are major problems because of the frequent moves required; and (3) size and efficiency increases in loaders, shovels, trucks, and draglines have kept alternative methods of overburden handling competitive. Nevertheless, prototype continuous excavators, moving conveyors, and stackers are being field-tested in a wide variety of specialized applications and show considerable promise. In the West a second generation of unitized coal haulers is coming into use.

Components

Innovation continues in components to make unit operations more productive and efficient. Improved controls including remote operation, automation, and information feedback are being developed. The efficiency and reliability of mining machines, in terms of their electrical, hydraulic, and mechanical systems, are being improved to reduce equipment downtime. More horsepower is being delivered to the point of work to increase equipment capacity. Taken together with innovation in equipment manufacturing processes, the result is a steady flow of evolutionary improvements designed to increase the capacity and reduce the cost of current mining equipment.

Mining Systems

Longer-range research also is under way that, although benefits will not be as immediate, may provide alternative solutions to the problems being addressed by applied research. Included are reaching an understanding of the systems aspects of current mining methods and basic research in rock mechanics and deposit characterization. Among new mining systems being investigated are hydraulic mining, in-situ gasification, and borehole mining; these three areas represent ideas that have progressed from concept to prototype and in some cases to full-scale operation. Evaluating such new mining systems requires balancing the unbridled enthusiasm of proponents against the "not invented here, it'll never work" stance of opponents. Therefore, it is most useful to use well-defined criteria such as technical risk, estimated cost, competitiveness, and field applicability in assessing the potential of these novel systems.

Innovation to Meet Changing Conditions

Increasingly in the next 20 years we will have to mine deposits under more difficult conditions. In some cases, existing systems simply will not work (e.g., room-and-pillar mining at deeper levels because of pillar strength limitations, and dragline mining in thicker overburden because of boom length limitations). In other cases, existing equipment will be rendered obsolete by the physical problems associated with thick underground seams that require multiple bench mining; thin underground seams that require scaledown of current equipment to the point where new configurations are necessary; and multiple seams that require rehandle in surface mines and interlevel roof control in underground mines. Moreover, if some of the dipping and faulted deposits that have been avoided in the past are to be mined, totally new approaches will be needed.

Innovation to Meet Regulatory Issues

Health and safety research, particularly in underground mining, has been well funded for nearly a decade and has produced improvements in ventilation, respirable dust control, roof control, cabs and canopies, operating controls, electrical safety, fire protection, lighting, and methane drainage. The reduction of deaths and accidents in mining and the provision of a more healthy working environment have been impressive.

Nonetheless, these achievements have not been without problems, particularly from the perspective of machinery manufacturers and mine operators who diverted research funds and engineering talent from improving productivity into complying with regulations. In addition, by separating health and safety research from production research, the government has divided funds and organizational responsibility. In the actual work place, however, health and safety and production are simply different aspects of a single team of men and equipment. Research to achieve integrated solutions through innovative technology has become fragmented and more difficult to achieve.

In surface mining, regulatory issues have had more to do with land reclamation than with safety. Improved approaches to selective overburden placement, groundwater control, contour grading, topsoil handling, revegetation, and acid water treatement have been developed. Shovel/truck mining may displace medium-size draglines in areas where overburden mixing will not meet reclamation requirements. It also may have greater use in mountain-top removal operations to meet head of hollow, valley-fill reclamation requirements. Use of large scrapers, dozers, and graders required for regrading has resulted in reclamation equipment investments that approach the investment for in-pit equipment in some areas. Other issues such as surface subsidence, classification of hazardous wastes, the impacts of overburden blasting, and the impact of mining on aquifers remain more at the stage of defining the problem rather than achieving solutions for it. Again, like health and safety matters, resentment occurs when money and talent are diverted to work on regulatory issues and when government research is funded and organized separately from production research, although the activities are integrated at the mine.

Current Research Activities

Many U.S. government agencies are investigating innovative coal extraction technologies. Although the U.S. DOE has the lead responsibility in production research, many other agencies are also involved in mining or mining-related research. They include the USBM, USGS, Office of Surface Mining, Mine Safety and Health Administration, and National Academy of Sciences.

Some liaison and coordination among these groups has been attempted. However, primarily because of differences required by the disparate legislation that fund these diverse activities and partly because of the lack of continuity in research organizations and goals experienced in Washington in recent years, the federal program remains fragmented. Such fragmentation hampers the sincere efforts of experienced researchers within these agencies. No focal point exists to communicate the basic underlying benefits of coal extraction technology and to coordinate and rank research activities. As a result, many programs compete rather than working synergistically.

In addition to government research, several universities with the help of state, federal, and private funding provide centers for basic and applied mining research. In addition, large manufacturers of mining equipment have continuing programs for developing new and improved product lines. The direction and implementation of this government, academic, and industry research are encouraged through the working committees, publications, and conventions of such organizations as the Society of Mining Engineers of AIME, National Coal Assn., and American Mining Congress.

Similar research programs are being undertaken in most of the major coal-producing countries such as the United Kingdom, Federal Republic of Germany, Australia, Poland, and the U.S.S.R. In addition to several bilateral agreements with these countries, the U.S. also is participating under the auspices of the International Energy Agency's Coal Working Party to create a Mining Technology Clearing House. The clearing house would maintain registers of current research projects. These should enable researchers to know of current parallel or complementary work in member countries and, thus, encourage active communication and collaboration without the usual delays encountered by waiting for completion of the work and publication of the results. As the worldwide implications of coal-based energy are becoming better understood, coal extraction technology and related matters are being studied more actively by such international organizations as the United Nations, International Inst. of Applied Systems Analysis, the World Energy Conference, and the International Energy Agency.

Conclusions

Coal extraction technology is a key link in the energy supply networks that deliver coal-based energy to the American public. Diverse regional conditions must be considered in implementing a program of research in coal extraction technology. Innovation urgently is needed not only to control costs and improve productivity but also to prepare for mining more difficult deposits and to respond to important regulatory issues. More emphasis is needed on coordination and continuity of purpose and personnel so that the combined impact of ongoing research by the government, universities, and industry will continue to make coal a feasible and desirable fuel for meeting our future energy needs.

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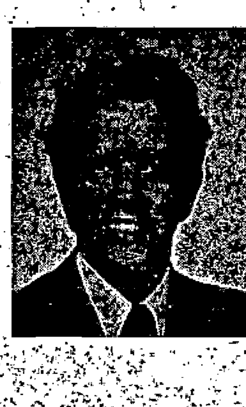

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