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PURSUING ENERGY SUPPLY OPTIONS: COST EFFECTIVE R. & D. STRATEGIES

REPORT

PREPARED FOR THE USE OF THE

JOINT ECONOMIC COMMITTEE
CONGRESS OF THE UNITED STATES

APRIL 27, 1981

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LETTERS OF TRANSMITTAL

APRIL 20, 1981.

To the Members of the Joint Economic Committee:

Transmitted herewith is a report entitled "Pursuing Energy Supply Options: Cost Effective R. & D. Strategies." This report was prepared at the request of Senator Lloyd Bentsen by the Congressional Research Service. It evaluates some 31 unconventional and conventional energy supply options to determine the most cost-effective Federal R. & D. options for maximizing energy production in the years 1990 and 2000.

The report by 16 CRS analysts was coordinated by George Tyler of the committee staff. Preparation of the report was under the general direction of L. Harold Bullis, Specialist in Science and Technology, who was assisted by Langdon T. Crane, Jr., Specialist in Science and Technology, Lani H. Raleigh, Specialist in Aerospace and Energy Systems, and John J. Schanz, Senior Specialist in Resource Economics and Policy. Authors of individual chapters of the report are indicated at the start of each chapter.

Sincerely,

HENRY S. REUSS,
Chairman, Joint Economic Committee.

APRIL 15, 1981.

Hon. HENRY S. REUSS,
Chairman, Joint Economic Committee, Congress of the United States, Washington, D.C.

DEAR MR. CHAIRMAN: I am pleased to send you the report entitled "Pursuing Energy Supply Options: Cost Effective R. & D. Strategies." This report was prepared at my request by the Congressional Research Service of the Library of Congress and includes contributions by 16 CRS analysts and specialists.

The report is designed to pinpoint the Nation's most cost-effective domestic energy supply R. & D. opportunities. In a pathbreaking effort, these analysts evaluated the present status and future prospects for some 31 conventional and unconventional energy supply options ranging from oil and coal to solar and nuclear energy. Future energy production in the years 1990 and 2000 for each of these options was determined based on the most practical and feasible projected Federal R. & D. programs. The results enabled the authors to identify domestic sources most subject to increased production as a result of further research.

This major analytical work will be of particular value to Congress and the Administration in efforts to identify those energy supply choices that will yield the Nation the greatest and fastest payback per Federal research dollar. In determining the most cost-effective Federal energy R. & D. options, the report stresses the great difficulty in achieving energy independence. It makes no recommendation whether that goal is realistic, but urges that a variety of the most promising options be pursued simultaneously to reduce our dependence on foreign oil.

The report contains some surprises. The most promising and cost-effective domestic sources of additional energy supply are heavy oils too thick for extraction with traditional technology, unconventional gas now trapped in coal, sandstone, and shale rock, and alcohol fuels. By 1990, the report projects that these three sources could be producing new energy supplies containing the oil equivalent of from 2 million barrels to 8 million barrels daily.

The authors discuss these and many other supply options in detail in an effort to improve the quality of debate regarding our energy future. They avoid the use of technical jargon and present this important material in a clear and accessible fashion. I believe they have enabled Congress to focus much more sharply on the energy choices we face.

The views expressed in this report are those of the authors and do not necessarily represent my views or the views of any other member of the Joint Economic Committee.

Sincerely,

LLOYD BENTSEN,
Member, Joint Economic Committee.

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SUMMARY *

I. Introduction

Considerable attention is now being focused upon the Nation's increasing dependence upon imported energy supplies and the effect of such imports upon the Nation's economic and strategic health. Much discussion has centered around prospects for reducing this dependency in the future and the means whereby such a reduction might best be achieved. It now appears clear that no single solution is likely to present itself; rather, the near and mid-term solution appears to be a complex mix of continued use of conventional energy supplies, development of a variety of domestic alternative energy sources, a reduction in overall energy growth requirements through a variety of conservation and efficiency techniques, and—at least for the foreseeable future—some degree of continued dependency upon foreign imports of energy fuels. The primary question, then, concerns the nature of this complex energy mix and how its composition may be changed favorably by actions that can be taken now. This report focuses upon one aspect of this question: how can the Nation best allocate its finite research and development (R. & D.) dollars to achieve the greatest reduction in energy dependency by the years 1990 and 2000 at the least possible cost, consistent with existing social, political, economic, and environmental constraints?

Energy is not only ubiquitous, it can be captured, transported, and eventually used in a variety of ways, thereby providing a variety of energy supply and use opportunities. Availing ourselves of any such opportunities, representing a major departure from past energy practices, that can significantly increase the domestic supply of energy, or that can significantly reduce the energy inputs now required by the U.S. economic system, clearly will require a major commitment to R. & D. This commitment will involve not only the development and testing of the more promising new energy technologies at scales that approximate commercial activity, but also will involve the cost of introducing such technologies into the mainstream of U.S. energy production and use.[1] Thus, the central problem is to determine what approaches to increasing domestic energy supplies best justify major Federal support. Considering the large number of possible choices, it appears unrealistic to attempt to pursue each with equal vigor. Since only a few are likely to make major contributions in terms of adequacy of return on Federal R. & D. investment, it is necessary to identify those few and thereby concentrate upon a manageable number of alternatives.

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*Summarized by L. Harold Bullis, specialist in science and technology.

[1] A willingness to make such a commitment is evidenced by recent enactment of Public Law 96-294, the Energy Security Act.

In making these choices, the relative attractiveness of each new technology should be to a considerable extent a reflection of both the level of expectation for adding to U.S. domestic energy production (or reducing the amount of primary energy input required) and the Federal support now considered needed to make that occur. From the viewpoint of Congress, the larger this ratio the more attractive the project becomes. While a ranking of this type is not a precise or absolute indicator of what are good or bad R. & D. ventures, it is a process that provides some useful insights. Obviously, given the judgmental nature of the exercise it is important to strike a happy medium between the optimism and pessimism that accompanies all evaluation of new technologies.

One important constraint has been placed on the scope of this study. Only those R. & D. opportunities that relate to the extraction, production, processing, transport, and conversion of energy between the source and the terminal user of the energy are examined. The intent is to restrict the investigation to examining how we can improve the supply side of our domestic energy equation. It was recognized that a detailed assessment of a large number of technologies would be long and costly. Hence, the analysis has drawn primarily upon the existing expertise of the current staff of the Congressional Research Service augmented by what the staff could readily draw out of the extensive literature on energy supply technology. We must also acknowledge that the results are not only to an appreciable extent judgmental in character but necessarily must deal in orders of magnitude rather than precise measures of future supply potential versus research costs. These uncertainties about feasibility, costs, or rewards have been identified at the appropriate places in the report.

Given these caveats, the report provides a general view of the research, development, and demonstration terrain that lies ahead, some sense of the difficulties that may be encountered in crossing it, and a rough estimate of the magnitude of the eventual energy yields over a future time period that has some meaning in terms of our now foreseeable energy problems. The problem we seek to resolve is the direction and kinds of activities that are needed today if we are to have reasonable expectations of an improved energy situation ten to twenty years hence.

II. Major Policy Issues

A capsule review of the current U.S. energy supply capability is not encouraging, nor is an assessment of the current status of the development of alternative sources of energy. Fortunately, energy import dependency is not necessarily of itself fatal, as shown by the experience of other nations that have long been—and still remain—more dependent upon such imports than is the United States. Indeed, the United States itself has never been self-sufficient in many of its resource needs. The major policy problem stems not only from the world's finite and dwindling petroleum resources, but also from the rapidity with which this limited energy capability has descended upon us, and the concurrent appearance of a petroleum producers' cartel. These developments prompt serious concern about U.S. energy supply security.

A major problem is that, for the first time, the United States must operate in what is frequently a non-competitive, seller's market in world energy. In seeking to extricate the Nation from this situation, the Congress faces an array of difficulties. One is time—time to decide on direction, time to legislate, time to implement, time to experiment, time to build—efforts measured in years and decades. Another difficulty is that of determining the best use of public funds for energy-related R. & D., and the fact that almost any aggressive domestic energy supply program will be extremely costly and probably run counter to many other national pressures and programs. At present, large infusions of Federal funds run counter to the current desires to control inflation and to limit or cut the expanded cost of Government. We are also reluctant to turn our backs on more than ten years of effort toward providing for the procedural needs and meeting the costs of environmental protection.

Dealing with these difficulties will, in most persuasive scenarios, require large amounts of Federal funds. Although "buying" a solution is a frequent, 20th century strategy, there is the question of whether we can afford the price this time. Government involvement does not eliminate the uncertainty in our energy situation, and it might increase the cost of the eventual answer to the problem without necessarily improving the quality of the solution or cutting the time needed to research it. There is understandable congressional apprehension that we may now be induced to purchase a herd of energy "white elephants" requiring disposal a decade from now. Subsidies once in place are difficult to withdraw without creating adverse industrial and public impacts.

III. The Future Supply and Demand Mix

Just as there is no current certainty as to the "best" pathway to enhancing our domestic supply situation, neither can we predict with precision the amount of energy the United States will actually need in the future. This is a reflection of more than a normal lack of confidence in energy demand forecasts. There is a strong likelihood that the United States is entering a period of significant adjustment both to higher price conditions as well as a possible functional change in the relationship between the consumption of energy and the general level of U.S. economic activity. The difficulty of analyzing our complex energy market has been compounded by a lack of experience in the response of energy consumers to high prices. Consequently, few of those who have studied the problem are willing to profess sufficient understanding of the mutual interaction of energy and the economy to make a rigorous forecast of the degree and timing of the change we are likely to experience between now and 2000. Essentially, we are still learning about the real potential for conservation by individual consumers as well as the impact of greater efficiency in industry.

Because of these difficulties, future supply analyses and demand forecasts continue to provide a fairly wide range of projections and judgments. For example, the 1979 report to the Congress by the Energy Information Agency projects U.S. supplies for 1990 to range from 77 to 80 quadrillion Btu's (quads). Similarly, EIA demand projections for the same year range from a low of 88 quads to a high of 93 quads, increasing to between 108 and 117 quads by the year 2000 and betwen 147 and 149 quads by 2020. Obviously, it is unwise to rely upon a single set of projections, or upon one source of data, for a perception of the future U.S. supply and demand for energy. It can be even more deceptive if separate projections of supply and demand are obtained from different sources and then used together. Such projections are rarely linked to one another by compatible assumptions about price, technology, and the state of the economy. However, perhaps the essential future is that virtually all recent projections, although recognizing that increasing energy prices are already substantially slowing the rate of growth of demand over that projected earlier, nonetheless exhibit a continuing energy import dependency beyond the year 2000.

IV. Resource Opportunities Versus Resource Needs

In general, energy is used for three basic purposes: to provide environmental protection and comfort, to process or transform materials, or to do work. The energy form chosen is usually matched to the energy use. Thus one kind of energy suitable for generating steam may not be useful for propelling an airplane or may be unattractive to the householder. It is more a question of physical compatibility, since the final delivery costs and potential uses of energy are also affected by the way nature provides the energy. A diffuse, low-temperature energy source will be used in an entirely different way than will a compact bundle of energy capable of yielding very high temperatures. All energy is initially provided as a free good by nature. The key variables are the costs of capture, conversion to a useful form, and final delivery.

With regard to cost, in the past the great natural advantage of the fossil and mineral fuels and prime hydroelectric power sites has been the large amount of energy concentrated at a single source point. Their present popularity reflects the fact that the amount of effort or cost required to gather and produce their contained energy in usable form has been relatively small compared to other potential sources of energy. The total, and frequently the incremental, cost of energy from these currently preferred sources can be extremely low, particularly if environmental threats and costs are ignored. In contrast, for example, most forms of solar energy, either directed or derived, normally display some combination of variability, dispersion, or low intensity.

With regard to form, it may be said that, despite man's long history of using organic substances for energy, both fossil and of recent origin, there still remain extensive opportunities for R. & D. to devise new and bettter ways of converting this material from its raw form to the most useful forms for final consumption—solid, liquid, or gaseous. Man has also employed the fluid flows of wind, surface water, and the tides to his advantage since pre-historic times, although the mechanical use of these energy forms has proved less useful in modern industrial societies. Also, the direct use of natural terrestrial or solar heat commands obvious attention.

With regard to delivery, it is interesting to note that the production of electricity now consumes approximately 30 percent of U.S. primary energy deliveries. There is a general consensus that this proportion will grow, perhaps reaching 50 percent by 2000. The use of electricity, however, has one serious physical drawback: the lack of mobility of the equipment used to generate the power. In addition, it is still costly to transport electric power over long distances or to deliver it in small packages at isolated locations. Other major forms of energy—most notably oil and coal—also have obvious costs associated with transport and delivery.

V. Prospects for Future Energy Supply Sources

In this study, 31 areas of nonconventional energy supply R. & D. have been identified and are examined in terms of the future energy that could be obtained from domestic sources beyond that which current projections indicate would be produced by merely following recent patterns of development. The 31 areas have been clustered into 8 separate groups, and within each group each technology is discussed in terms of the current situation, an examination of the resource potential, a summary of the R. & D. effort being made, and an identification of what may be required in time and effort to move each energy supply technology beyond its present pattern of development. In addition to quantifying the additional energy to be expected in the time intervals specified, the obstacles and uncertainties that are likely to be encountered are discussed. For completeness, background information has been given for the major conventional energy sources that now supply the bulk of the Nation's current energy needs.

A. Conventional Energy Sources

The conventional energy sources assessed were coal, light-water nuclear reactors, natural gas, and oil.

1. CONVENTIONAL COAL

Coal is mined by two general methods, surface or underground, depending upon the geological conditions. the coal reserves of the United States total approximately 437 billion short tons, of which recoverable reserves are currently estimated at 283 billion tons, based upon 57 percent recovery from underground mines and 90 percent from surface mines. Identified U.S. coal resources, however, are postulated at more than 1.7 trillion tons. At present, coal represents about 90 percent of the U.S. fossil fuel reserves but only contributes about 20 percent of U.S. energy needs. Coal production in 1979 amounted to approximately 770 million tons. The increased use of coal is dependent upon the future development of new technologies for its extraction, transport, cleaning, upgrading, and burning in accordance with often-changing environmental constraints. Considerable research and development, some supported by DOE, is now being undertaken in these areas. One of the major factors inhibiting the increased use of coal is the need for investment of large amounts of capital. For example, to meet the goals of the revised Project Interdependence Blueprint of about 1.0 billion tons/year by 1985 and 1.5 billion tons/year by 1990 would require an investment in new mines estimated at from $19 billion to $57 billion, depending upon in what part of the country the coal was mined. Nonetheless, the use of coal is expected to accelerate, especially as liquefaction and gasification technologies develop to replace depleted oil and gas supplies in the early part of the next century.

2. CONVENTIONAL LIGHT WATER NUCLEAR REACTORS

At present, 69 light water nuclear reactors are licensed for operation in the United States, 42 of which are pressurized water reactors and 27 of which are boiling water reactors. These reactors represent a total of about 9 percent of the current electric generating capacity of the United States. This compares with 11.5 percent in the first half of 1979, and 12 percent during 1978. The decrease is largely due to shutdowns to modify reactors in seismic risk areas and to shutdowns relating to the Three Mile Island accident. Nuclear power represented about 52 Gw (gigawatts) of U.S. electricity production capacity as of January 1, 1980. Current R. & D. programs include investigations and questions concerning reactor safety and the disposal of radioactive wastes. It is estimated that nuclear capacity by 1990 could range from as little as 131 Gw to as much as 182 Gw. Similarly, estimates for the year 2000 range from a low of 181 Gw to a high of 300 Gw.

3. CONVENTIONAL NATURAL GAS

Natural gas is closely related to crude oil and is formed under similar geological conditions (see 4 below). Hence the search for natural gas closely parallels the search for oil. The production of conventional natural gas, however, is much more efficient than is the production of oil, with recovery rates as high as 75 to 80 percent of the original in-place gas, depending upon the permeability of the reservoir. Proved reserves of domestic natural gas totaled 194.9 trillion cubic feet at the end of 1979, and inferred reserves—as estimated by the U.S. Geological Survey—now amount to an additional 201.6 trillion cubic feet. In 1979, domestic production of natural gas amounted to 19.9 trillion cubic feet. Current industry R. & D. is concentrated upon improving drill bit design, developing new technology to monitor hole conditions during drilling, turbodrill design, and improved geophysical equipment. Federal R. & D. is directed at improving drilling and off-shore technology systems, including research on seafloor instrumentation. Despite this R. & D., domestic production of conventional natural gas is expected to decline over the next several decades as reserves decline. By 1990 production is expected to amount to no more than about 17.1 trillion cubic feet/year, and may amount to even less by the year 2000 unless many new giant gas fields are discovered—an unlikely prospect.

4. CONVENTIONAL OIL

The search for oil begins with the use of general geological knowledge to locate geographic areas that are likely to contain oil reservoirs, and continues with both geological and geophysical studies to determine the structure and stratigraphy of the area and to help locate specific drilling sites. Similar methods are used for locating oil offshore except that a platform is needed to support the drilling equipment. Proved conventional oil reserves, at the close of 1979, were estimated at 27.1 billion barrels, with inferred reserves estimated at from 13 to 21 billion barrels. Estimates by the U.S. Geological Survey indicate undiscovered domestic oil resources may amount to from 42.6 to 119.6 billion barrels, for a total estimate resource potential of from 82.7 to 167.7 billion barrels. Domestic production in 1979 amounted to 2.96 billion barrels, far below the amount consumed. Current R. & D., largely conducted by the petroleum industry, concerns drill bit design, turbodrills, and improved geophysical sensors. Despite this research and increased exploration and drilling activity, prospects for increasing U.S. production of conventional oil in the future appear poor. The cost of exploration and drilling is high, and the success rate is relatively low. It has been estimated that it would cost almost $180 billion to drill the number of new field wildcats believed necessary to maintain 1978 discovery levels through 1990. Thus, it appears unlikely that additions to proved reserves will be sufficient to maintain current production levels through the next two decades. Hence, the prospects are that domestic oil production will almost certainly continue to decline beyond the 1990's, with the only possibility of reversing this decline being the slim chance of many giant field discoveries in very remote and difficult environments. The extensive employment of enhanced oil recovery techniques cannot be expected to reverse this downward trend.

B. Coal-Based Technologies

The coal-based technologies assessed included coal liquefaction, high-Btu coal gasification, magnetohydrodynamic power generation, as well as various other technologies for the utilization of coal.

1. COAL LIQUEFACTION

Coal liquefaction is the process of converting pulverized coal to synthetic liquid fuels, either by direct or indirect hydrogenation, to increase the proportion of hydrogen to carbon found in the coal. Domestic coal resources and reserves are sufficiently large so as to pose no constraint to the development of a large-scale coal liquefaction industry (see section above on conventional coal). At present, at least 11 different first- and second-generation liquefaction processes are under consideration, but thus far only experimental quantities of coal liquids have been produced in the United States. The current R. & D. strategy of DOE is to support several liquefaction processes concurrently from the laboratory scale, through process development units, with only the most promising processes then being advanced to the pilot plant stage and subsequent demonstration through joint Federal-industry efforts. These testing and other commercialization efforts are expected to increase substantially as the synthetic fuels effort recently authorized by the Federal Government gets underway. Currently, it is estimated that an average commercial production level of from 100,000 to 200,000 barrels/day of oil equivalent could be reached by 1990, possibly increasing to from 0.5 to 1.2 million barrels/day by the year 2000.

2. HIGH-BTU COAL GASIFICATION

High-Btu coal gasification is a process in which pulverized coal is converted into combustible gas which has the same heat content as pipeline quality natural gas. In general, this process involves the thermal decomposition of the coal followed by gasification or combustion of the resulting char, sometimes under pressurized conditions. Numerous first- and second-generation gasification processes are under consideration, but thus far only experimental quantities of high-Btu gas have been produced in the United States. Current R.D. & D. strategy is similar to that for coal liquefaction, as discussed above. Should industrial commercialization efforts prove fruitful, it is estimated that high-Btu coal gasification could produce from 0.5 to 1.0 billion cubic feet of gas per day by 1990. Optimistic estimates for the year 2000 range as high as 3.3 trillion cubic feet of high-Btu gas per day.

3. MAGNETOHYDRODYNAMIC POWER GENERATION

Magnetohydrodynamic power generation, or magnetohydrodynamics (MHD), is a method for converting heat directly into electrical power, without the usual intermediate step of first boiling water to run a steam generator. Although in principle any high-temperature heat source could be applied to an MHD generator, present efforts are largely aimed at utilizing the technology in conjunction with coal-fired combustors, at a potential fuel saving of up to 50 percent over conventional methods of generating electricity from coal. At present, although no fundamental scientific barriers to the technology appear to exist, MHD is making no contribution to U.S. energy supplies. Individual components of MHD systems have been built and tested, but the technology remains far from commercial development. Current research on MHD, largely performed under contract with DOE, is proceeding in three overlapping phases: first, development and testing of MHD core components at up to 50 megawatts thermal (Mwt); second, scale-up of these components to a complete pilot-plant of 250 Mwt; and third, construction of a full-scale commercial demonstration plant generating approximately 1,000 Mw of electricity, possibly by 1987. Hence, it is estimated that by 1990 the best that might be expected is a pilot-scale plant producing about 500 Mwt. However, it appears possible that a few 1,000 Mw plants could be in operation by the year 2,000.

4. OTHER TECHNOLOGIES FOR THE UTILIZATION OF COAL

Four additional technologies for the utilization of coal were assessed: low-Btu coal gasification, medium-Btu coal gasification, combined cycle coal gasification, and atmospheric fluidized bed combustion.

(a) Low-Btu coal gasification.—Low-Btu gas, composed principally of nitrogen, carbon monoxide, and hydrogen, is produced by the combustion of coal in the presence of steam and air and has a heating value of less than 200 Btu per cubic foot, as compared with about 1000 Btu per cubic foot for most natural gas. During the 1920's and 1930's thousands of low-Btu coal gasifiers were in operation in the United States, but these were superceded by the more convenient pipeline natural gas supplied by the developing domestic natural gas industry. At present, the amount of low-Btu gas being produced domestically is negligible. However, processes and

equipment similar to those used earlier remain available commercially, updated and improved in some respects and modified to conform with current environmental constraints. Commercialization of these existing systems, rather than additional R. & D., is judged to be the most crucial step at this time. The DOE projects that low-Btu coal gasification may amount to 0.16 to 0.2 quads by 1990, and possibly as much as 1.0 quad by the year 2000.

(b) Medium-Btu coal gasification.—Medium-Btu gas, composed largely of carbon monoxide and hydrogen, is produced by the combustion of coal in the presence of steam and oxygen and has a heating value of 300 to 600 Btu per cubic foot. Although more than 100 commercial-size plants are now in operation overseas, none have yet been built in the United States, despite the fact that first-generation processes and equipment for producing medium-Btu gas are available commercially. The DOE projections for medium-Btu coal gasification are 0.3 to 0.5 quads by 1990, and 1.0 to 4.4 quads by 2000.

(c) Combined-cycle coal gasification.—Combined cycle coal gasification involves the low-Btu gasification of coal, following which the product or resulting gas is cleaned and used as a fuel for a high-temperature gas combustion turbine to produce both heat and electricity. Although separate components of the system have been successfully demonstrated, no fully integrated system has yet been operated. Substantial technical development is still required, including additional work on emission control technology. The DOE estimates of combined cycle coal gasification output are for 0.1 quad by 1990 and 3.0 quads by the year 2000.

(d) Atmospheric fluidized bed combustion.—Atmospheric fluidized bed combustion involves the burning of coal, or other fuels, in a bed of limestone, or other material, to remove sulfur and thus permit the burning of coal in an environmentally clean manner. Heat is removed by boiler tubes immersed in, as well as located above, the combustion chamber. The process is adaptable to a wide variety of applications, including both utility and industrial steam generation. About 20 atmospheric fluidized bed combustion units, ranging in size from about 0.3 to 30 Mwe, are now in operation or in the design or construction stage in the United States, producing a total output of about 60 Mwe. Additional R.D. & E. appears necessary on industrial-scale boilers and heaters of lower cost and improved performance and reliability, as well as on coal feed facilities. Nonetheless, the technology appears ready for industrial-scale commercial prototype construction. A major difficulty to commercialization is the reluctance of many users to risk current productive capacity to promote this still-uncertain technology, despite savings which might accrue. The DOE estimates 0.8 quad output by 1990, and 6.0 quads by 2000 for this technology.

C. Direct Sunlight Technologies

Six technologies that essentially utilize sunlight directly were assessed: agricultural and industrial process applications, passive solar energy techniques, photovoltaic power conversion, satellite power stations, solar heating and cooling for buildings, and solar thermal power conversion.

1. AGRICULTURAL AND INDUSTRIAL PROCESS APPLICATIONS

Solar collector systems for agricultural and industrial process heat applications produce hot air, hot water, and steam ranging from temperatures of less than 212 degrees F to greater than 350 degrees. Much of the technology for temperatures up to about 350 degrees F is adapted from solar heating and cooling systems, whereas for higher temperatures the applications draw primarily upon high-concentration collectors developed for solar thermal electric techniques. At present, these applications account for about 39 percent of the total energy used in the United States. However, aside from a small commercial market for crop dryers, agricultural and industrial solar heat applications remain insignificant. In the industrial area, current technology can satisfy many low-temperature requirements, but for higher temperatures the technology is not well-advanced. Past R. & D. both for agricultural and industrial process purposes has placed primary emphasis upon developing systems with state-of-the-art components, relying for future progress upon R. & D. now underway in other solar-related programs. The long-term prospects for the technology appear primarily dependent upon achieving lower solar system costs, and especially lower collector costs. Should the cost problem be resolved, from 1 to 2 quads of agricultural and industrial process energy requirements might be met by 1990, possibly increasing to 2.2 quads by the year 2000.

2. PASSIVE SOLAR ENERGY

Passive solar heating and cooling techniques are employed to collect, circulate, and store thermal energy to heat buildings, or to take advantage of natural air flows to cool buildings by removing unwanted heat energy. Buildings may be classified in four categories of increasing utilization of passive solar design: conventional, energy efficient, sun-tempered, and true passive solar. Despite the fact that the basic design principles are well-known and that suitable materials are readily available, passive solar technology has barely begun to penetrate the new home market in the United States. A major obstacle appears to be that present building and housing codes are not readily adaptable to passive solar design, are difficult to change, and vary from one locality to another. Should these problems be overcome, however, a progressive increase in passive solar homebuilding might achieve an energy savings of about 0.4 quads per year by 1990, and possibly as much as 1.1 quads per year by the year 2000.

3. PHOTOVOLTAIC ENERGY CONVERSION

Photovoltaic energy conversion involves the direct conversion of sunlight to electricity by solar cells. Typically many such cells are sealed into panels, and several panels are then electrically interconnected to form an "array." Arrays are either flat plate, which absorb sunlight as received, or utilize lenses or reflectors to concentrate the sunlight onto the cell area. Although the industry is still in its infancy, solar cells have been in use since the mid-1970's, primarily at small, remote, unmanned sites. Current R. & D. is directed mainly at reducing the cost of solar cells, now made by highly labor-intensive batch processing techniques. Other problems include the lack of available systems and systems experience, as well as the limited availability of solar-grade silicon. Photovoltaic power is unlikely to contribute significantly to U.S. energy supplies until it becomes competitive with utility-generated power, possibly by 1986 should DOE programs prove successful. Consequently, its contribution by 1990 is not expected to exceed about 0.1 quad. Its likely maximum contribution by the year 2000 is estimated at about 1 percent of the then-generated U.S. electrical energy of about 5 x 10^{12} kwh.

4. SATELLITE POWER STATIONS

A satellite power station (SPS) is conceived as a geosynchronous Earth orbit satellite that would collect solar energy above the Earth's atmosphere and convert it into electricity for subsequent transmission to the ground, thereby avoiding the screening effects of the atmosphere, as well as problems inherent in collecting solar energy due to the diurnal cycle and inclement weather. Transmission of electricity is envisioned as most likely using microwaves or, perhaps, lasers. The concept is only now undergoing feasibility determination studies, with major concern being addressed to four areas: environmental aspects, social aspects, comparative costs vis-a-vis other electricity sources, and technology development. The primary objective of current R. & D. is to determine whether or not the concept warrants construction of a prototype SPS. The first full-scale SPS is expected to cost about $100 billion, with each additional SPS costing an estimated $11.5 billion. At present it appears highly unlikely that energy from satellite power stations will make any contribution to U.S. energy supplies by 1990 or 2000.

5. SOLAR HEATING AND COOLING FOR BUILDINGS

Solar heating and cooling techniques provide a broad range of opportunities for utilizing a variety of solar collector systems and building design principles to provide hot water and space heating and cooling for both residential and commercial buildings. Active systems are differentiated from passive systems discussed earlier in this report (see section 2, above), by their typical employment of electric pumps to circulate a heat transfer medium. Currently an estimated 100,000 installations, most of which are domestic hot water heating systems, exist within the United States and provide an energy output of about 250,000 barrels of oil equivalent per year. Current Federal emphasis is upon the commercialization of existing subsystems, rather than with R. & D. to develop new systems, and also in addressing such problem areas as subsystems costs, quality control, overall performance, and societal and institutional aspects of widespread implementation. At present, employment of solar heating and cooling is falling far below goals set by the National Energy Act and may provide less than about 0.7 quads by 1990. The best potential contribution of both active and passive solar energy systems in residential and commercial applications is estimated by DOE as 2.4 quad of energy in the year 2000.

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6. SOLAR THERMAL POWER CONVERSION

Solar thermal technology involves the use of highly-concentrating mirror configurations to produce high-temperature heat which can then be used directly, converted into electrical or mechanical energy, or into a combination of these. Two basic system configurations, power towers and distributed receivers, can be sized from a few kilowatts to hundreds of megawatts. Although technical feasibility has been proven and no scientific breakthroughs are needed for deployment, the technology for both small and large-scale systems is still very much in the developmental and demonstration stages. Current R. & D. is primarily directed toward reducing system and subsystem costs through enhanced performance, improved collectors, higher temperature capabilities, and by gaining utility and industry experience in field experiments. Since initial market penetration is not anticipated until the 1985–1995 timeframe, it appears unlikely that the technology will contribute significantly to U.S. energy supplies by 1990, or provide more than about 0.03 to 0.1 quads of energy by the year 2000.

D. Fluid Hydrocarbon Technologies

The fluid hydrocarbon technologies assessed were heavy oil, oil shale, and unconventional gas.

1. HEAVY OIL

Heavy oils are crude oils that cannot readily be extracted from reservoirs because of their viscous resistance to flow at existing temperatures. However, their mobility can be improved, and their recovery thus promoted, by employment of a variety of heating techniques: by injecting a hot fluid, usually steam or hot water; by burning some of the heavy oil in place in the reservoir; or, in rare instances, by electric heating. Domestic resources of heavy oil are estimated at between 110 and 125 billion barrels, of which recoverable reserves may amount to from 7.5 to 20.5 billion barrels. Current domestic production of somewhat more than 500,000 barrels per day is restricted primarily by economic and environmental constraints, rather than by a lack of technology. Current R. & D. is directed toward improving techniques for heating reservoirs more effectively and efficiently, toward the study of additives to improve the sweep efficiency of a steam flood, and on research concerning the extension depth limits for steam injection methods. Production of heavy oil is expected to double by 1990 to a rate of about one million barrels per day, but then is expected to remain at about this rate for the next decade.

2. OIL SHALE

Oil shale is a sedimentary rock containing various amounts of kerogen, a solid organic material which, when heated to about 900 degrees F, decompose into hydrocarbons and a variety of solid, largely unusable wastes. The hydrocarbons can be processed into liquid and gaseous petroleum products, including both jet and diesel fuels. Domestic resources of high-grade oil shale amount to an estimated 730 billion barrels of oil equivalent, and leaner oil shares are estimated to contain an additional 26 trillion barrels. However, the economic feasibility of commercial-scale processing technology has not yet been demonstrated, and only experimental quantities of shale oil are currently being produced in the United States. Current Federal R. & D. is directed toward improving the economics of oil shale processing, improving energy efficiency, achieving greater processing yields, reducing environmental emissions and residuals, and developing processes that may reduce the requirements for water. If commercialization of the technology proceeds as now planned, an average daily production level of 60,000 to 250,000 barrels of shale oil may be reached by 1990, and a level of possibly 180,000 to 450,000 barrels per day may be reached by the year 2000.

3. UNCONVENTIONAL GAS

Unconventional gas is usually considered as that gas occurring in four geologic environments: dissolved or entrained in hot geopressured waters, in joints and fractures or absorbed into the matrix of Devonian age shales, in tight (impermeable) sandstones, and in coal seams. Estimates of total resources of such gas range from about 782 to 3140 trillion cubic feet (tcf), of which about 12.7 to 13.5 tcf are considered recoverable reserves. It is estimated, however, that improved technology might increase recoverable reserves to a maximum of about 1400 tcf. Current production of such gas amounts to about 1.1 tcf/year, largely from tight sandstones but with some contribution from Devonian shales. Current activity is directed toward achieving meaningful increases in the levels of gas production from marginal wells and unconventional gas resources, identifying incentives to stimulate private development, and resolving institutional, legal, and environmental barriers to development. However, the major requirement for commercialization is said to be increased economic incentives. Should development proceed satisfactorily, production of unconventional gas could amount to roughly 2.1 to 9.6 tcf/year by 1990, declining thereafter during the next decade.

E. Organic Conversion Technologies

The organic conversion technologies addressed were those three expected to provide the major energy contributions during the next two decades: energy from municipal solid wastes, and ethanol and methanol.

1. ENERGY FROM MUNICIPAL SOLID WASTES

Several processes have been developed for recapturing and utilizing the energy content of the organic or combustible materials discarded as municipal solid waste. Such wastes may be burned directly for their heat energy, with subsequent removal of non-combustible residues, or may be first separated from the non-combustibles and processed into so-called refuse-derived fuel, or into gaseous or liquid products, which may then be used as—or mixed with—conventional fuels such as oil or coal. It is estimated that the theoretical energy potential of domestic wastes produced every year is roughly equivalent to that of 200 million barrels of oil. However, although about 60 commercial or large-scale systems are now either in the final planning, construction, or operational phase, less than about 10,000 barrels per day of oil equivalent is now being produced in the United States. Current R. & D. is directed toward reducing materials problems (e.g., corrosion) encountered in existing systems, improving the efficiency of current operations, and advancing the current state of technology. The current and anticipated level of industrial activity indicates that about 20,000 to 85,000 barrels per day of oil equivalent may be produced by 1990.

2. ETHANOL

Ethanol (ethyl alcohol) can be used directly as an automobile fuel or can be mixed in a 10-percent solution with gasoline to provide a fuel popularly known as gasohol, which is now being sold at more than 1,000 gasoline stations throughout the United States. Ethanol is produced by the fermentation and subsequent distillation of various grains, sugar cane and beets, and—experimentally—from cellulose. The technology for manufacturing ethanol is well-understood but requires improvements to make gasohol a practical alternative fuel. For example, it is not yet clear as to whether the energy content of ethanol would be significantly greater than the energy required to produce it in the first place, even when produced in modern, efficient plants. Additional considerations, as yet unresolved, include the economics of alcohol fuels manufacture, automotive mileage achieved, the availability of adequate feedstocks, and environmental pollution. Should these questions be resolved favorably, it is estimated that production of ethanol for fuels from food processing wastes, grains, and sugar crops might amount to as much as 7.2–41.2 billion gallons per year by 1990. Should techniques for producing ethanol from wood and agricultural resides prove commercially feasible, annual production of ethanol for fuels might range as high as 54 billion gallons by the year 2000.

3. METHANOL

Coal, wood, or cellulose urban wastes can be subjected to physical and chemical reactions to produce methanol (methyl alcohol) which can then be used, like ethanol (section 2, above), either by itself or blended with gasoline to provide an automobile fuel. However, no commercial facilities for converting any of these materials to methanol now exist, nor is methanol now being widely used as a motor fuel. Current R. & D. is concerned with mechanical operating difficulties in using methanol as a motor fuel, phase separation due to the limited solubility of methanol in gasoline, corrosion of automobile components made from plastics or rubber, and the toxicity of methanol to humans. All things considered, it appears unlikely that methanol will be available in significant quantities for use as an automobile fuel by 1990. However, should a major developmental effort be successfully undertaken, annual production could reach almost 14 billion gallons by the year 2000, or more than enough to provide a 10-percent methanol "gasohol" blend for all the gasoline expected to be used by then.

F. Nuclear Technologies

The three advanced nuclear technologies assessed were advanced converter reactors, breeder reactors, and nuclear fusion reactors.

1. ADVANCED CONVERTER REACTORS

Advanced converter reactors are nuclear reactors which have better fuel utilization than current-employed light water reactors, but which do not produce more fuel than they consume, as do breeder reactors. Three types of advanced converter reactors are now under consideration: improved light water reactors, heavy water reactors, and high temperature gas reactors. None of these three nuclear technologies is at present making any contribution to U.S. energy supplies. With regard to current R. & D., improvements in the fuel utilization of light water reactors may be possible by improving the design of nuclear fuels and by changing fuel management techniques: although modifications of reactor cores may be necessary, it is expected that the changes will be such as to allow them to be retrofitted to existing light water reactors. Improvements in fuel utilization of heavy water reactors, which use water made from deuterium as both a coolant and a moderator, can be realized by mixing heavy water and light water in varying proportions depending upon the age of the fuel. Improved fuel utilization by high-temperature gas reactors, which use fuel pellets incorporated into graphite blocks rather than long fuel rods, may be achieved through the higher thermal efficiencies and the improved burnup and conversion ratios which may be possible with these reactors, compared with conventional LWRs. No contribution to U.S. energy supplies by 1990 is anticipated for either heavy water or high-temperature gas reactors. However, should it prove possible to retrofit improvements in the design of fuels and reactor cores to existing and planned light water reactors, a 15-percent saving of uranium may be achievable by 1990. Possibly an additional 15-percent saving may be achievable by the year 2000.

2. BREEDER REACTORS

A breeder reactor is a type of nuclear reactor which, in addition to producing energy, is able to produce more usable fuel than it consumes. Attention has been focused primarily upon four kinds of breeder reactors: the liquid metal, which uses a liquid metal—typically sodium—to cool the reactor core and for transfer of heat; the light water, which is essentially a light water reactor with a core designed to maximize the conversion of fertile material; the molten salt, in which the fuel itself is a liquid; and the gas cooled fast reactor, which uses helium gas as a coolant. The liquid metal fast breeder reactor, the most developed of these four designs, is now in the demonstration stage of development; primary attention is being focused upon the testing of breeder reactor fuels and materials, as well as the acquisition of sufficient design and development experience to permit the construction of a demonstration plant. With regard to the light water breeder reactor, the immediate objective of R. & D. is to confirm that breeding can be achieved in existing and future systems. Development of the gas cooled fast reactor, originally intended as a backup to the liquid metal breeder, has been terminated. Further development of the molten salt breeder reactor, also terminated, may be re-evaluated in the light of new concerns over the proliferation dangers of plutonium. No contributions to U.S. energy supplies is anticipated from any breeder reactor by 1990, but the first commercial breeder reactors could become available shortly after the year 2000.

3. FUSION

Unlike nuclear fission reactors which utilize the energy that is released by the splitting of heavier elements into lighter fragments, nuclear fusion reactors would utilize the energy that is released when lighter elements combine to form heavier elements. First-generation reactor designs are based upon combining deuterium and tritium, confined either magnetically or inertially in the form of a hot plasma, to form helium. Resources of deuterium, found in seawater, are virtually unlimited, and resources of lithium, from which tritium can be obtained by breeding, are also vast, although in increasing demand for other purposes. However, no fusion technology has yet demonstrated scientific feasibility or the ability to produce as much energy as is consumed in the process. Current magnetic confinement R. & D. is focused primarily on major plasma physics and technical/engineering problems. Inertial confinement R. & D. is focused primarily upon the development of a driver with durability, high efficiency, high energy, high repetition rate, and short pulse length, and upon the fabrication of a target pellet which can reach thermonuclear burn. Because of the early state of development of this technology and the formidable problems yet to be resolved, it is unlikely to make any significant contributions to U.S. energy supplies until at least 2040 unless the current pace of the program is greatly accelerated.

G. System Efficiency Technologies

The major system efficiency technologies that were considered for assessment were cogeneration, and several possibilities for achieving conservation and efficiency in the use of energy.

1. COGENERATION

Historically the term cogeneration referred to the practice of a power plant generating steam supplies beyond the amount needed to make electricity, and selling the extra steam to an industrial user. In recent years the term has come to broadly include all types of add-on systems which increase the useful yield of power of steam generating systems. Two kinds of systems—"topping" and "bottoming"—predominate. A topping cycle involves the initial use of combustion heat to power a high-temperature electrical generator, followed by use of the remaining heat to generate steam. A bottoming cycle involves the powering of a special closed-cycle, low-temperature generator with the residual waste heat present in the exhaust from a conventional steam turbine, which may amount to more than 70 percent of the original energy. Older cogeneration techniques such as the sale of process steam and district heating are well proven. However, the new technology of enhancing power generation through the application of topping and bottoming cycles is now in the research and development phase. Commercialization will depend upon the outcome of current R. & D. to help determine lifetime, reliability, and economic feasibility. It has been estimated that the maximum ultimate fuel saving potential through cogeneration in utility power plants is about 0.2–1.52 quads in 1990, increasing to about 2–6 quads in 2000.

2. CONSERVATION/EFFICIENCY

Although energy conservation is most frequently discussed in terms of demand, definite possibilities exist for conservation on the supply side, as well. Within this context, demand-side energy conserved can be considered the equivalent of new energy supplies. Essentially, conservation becomes a matter of increasing energy production, delivery, and distribution systems efficiencies so that existing demands for energy can be met with minimum energy resource requirements. As a practical matter, the bulk of the energy consumed in the United States is employed in the form of electricity or heat, including the use of electricity for heating purposes. Most of the electrical power consumed in the United States is produced at present by coal-, oil-, and gas-fired generators with a smaller contribution from nuclear-fission, hydro, and geothermal powered generators. Although prospects exist for at least some increase in efficiency of these various technologies by 1990 or the year 2000, no reliable estimate of the combined savings possible through achieving these efficiencies is available. Similarly, the possibility for efficiency savings in the transmission of electrical energy through the development of new, low-loss materials, or the use of high-voltage AC or DC transmission lines, is attractive but inadequately assessed. The use of coal slurry pipelines, now being considered, may result in a saving in costs but not necessarily in energy.

H. Other Technologies

A number of other alternative energy technologies were assessed that do not fall clearly within the categories discussed above. These included fuel cells, geothermal energy, hydrogen, low-head hydropower, ocean thermal energy conversion, and wind energy.

1. FUEL CELLS

Fuel cells convert fuel into a continuous flow of electricity by means of chemical reactions taking place within the cells. Although several chemical reactions are feasible, the fuel cells under development today depend upon the oxidation of hydrogen to produce electricity. Fuel cells having operating efficiencies of more than 50 percent have been fabricated, as contrasted with conventional power plant average efficiencies of about 35 percent; the maximum theoretical efficiency of a fuel cell is about 83 percent. Since any hydrocarbon or carbon fuel can be reformed to supply hydrogen for oxidation in a fuel cell, resources are virtually unlimited. At present fuel cells are making no contribution to U.S. energy supplies. Current R. & D. is focused upon demonstrating the suitability of the phosphoric acid fuel cell as an on-site source of power, and upon the thermal integration of a molten carbonate fuel cell with a coal gasifier system. Significant energy savings by employment of fuel cells is not anticipated by 1990, but overall fuel savings of up to 2.5 percent in the generation of electricity may be achievable by the year 2000.

2. GEOTHERMAL ENERGY

Geothermal energy is generally defined as that portion of the Earth's heat contained within the crust relatively near the surface. Although in most areas this heat is so diffuse that it cannot be economically recovered, in some areas it is sufficiently concentrated so as to be recoverable as steam or hot water which can be used directly for space heating and for industrial and agricultural purposes, or indirectly through the generation of electricity. Total domestic geothermal resources, comprised of hydrothermal convection systems, geopressured deposits, hot tight rock deposits, and magma systems, may amount to as much as 50 million quads. However, current U.S. geothermal production of electric power is only about 663 Mwe and less than 20 Mwt. Research activity is concentrated upon refining and updating the assessment of domestic geothermal resources; the reduction of costs and uncertainties in reservoir exploration, development, and utilization; the development and demonstration of cost-effective heat exchangers for a wide range of geothermal fluids; and the development and demonstration of environmental impact control technology. It is estimated that if current Federal geothermal programs prove successful, electric power generating capabilities might reach 10 Gw by 1990 and possibly 20 to 40 Gw by 2000. Direct heat applications may amount to 0.2 to 0.4 quads by 1990 and 0.5 to 2 quads by 2000.

3. HYDROGEN

Hydrogen is now produced from water, natural gas, or coal. Advocates of a "hydrogen economy," based upon the widespread use of hydrogen energy, forsee the large-scale separation of water into hydrogen and oxygen, using a non-fossil fuel energy source such as nuclear or solar energy. The hydrogen thus produced would be transported through pipelines and burned to provide fuel for various needs. Since the burning of hydrogen produces water, the technology would essentially comprise a huge closed system of virtually infinite resources. At present, the use of hydrogen as a fuel is limited to experimental applications. Current R. & D. largely concerns various aspects of the production, storage and transport, and burning of hydrogen. No significant contribution by hydrogen to U.S. energy supplies is envisioned until at least 2020.

4. LOW-HEAD HYDROPOWER

Hydropower is the production of electric power from rivers and streams either by use of the water's gravitational fall or the kinetic energy of its motion. Hydroelectric powerplants can be attractive because they utilize a renewable energy resource and produce electric power over long service lives, although they also can have adverse environmental and other impacts. The total physical low-head hydropower resource of the United States is estimated at about 16.4 Gwe. At present, low-head hydroelectric facilities (15 Mw and smaller) amount to about 3,000 Mw capacity, producing in excess of 15 billion kwh of electric energy per year. Since hydropower is a fully-developed technology, low-head hydropower is almost totally a matter of commercialization. Hence, the major considerations being addressed include technical readiness, economics and financing, environmental readiness, institutional factors, and information transfer. Although the contribution of low-head hydropower to current U.S. energy supplies is small, expectations are that installed capacity may amount to about 6 Gwe by 1990 and about 18.9 Gwe by the year 2000.

5. OCEAN THERMAL ENERGY CONVERSION

Ocean thermal energy conversion (OTEC) exploits the temperature differences that exist between warm surface water and the cold, deep ocean water below. The total potential OTEC resource is estimated at from 100 million to 10 billion Mwe, of which approximately 100,000 Mwe is considered potentially exploitable. At present, there is no on-line OTEC generating capacity in the United States. Although proof-of-concept design studies have been completed using state-of-the-art technology, and although OTEC operating principles are well-known, complex engineering and cost problems remain to be solved. Current R. & D. includes the thermal performance of OTEC heat exchangers and related biofouling, cleaning, and corrosion of heat exchanger surfaces; the refinement, optimization, and further engineering development of systems and subsystems; and study of possible adverse environmental effects. It is not anticipated that OTEC will make any significant contribution to U.S. energy supplies by 1990, but could contribute as much as 3 Gwe installed capacity by the year 2000.

6. WIND ENERGY

A wind energy conversion system is any machine or device utilizing the energy of the wind to produce mechanical energy which then can be used directly as an energy source or which can be converted into electrical energy. In addition to traditional windmills, the technology includes many different forms of wind machines that turn on horizontal or vertical axes. Although wind can be considered a virtually limitless resource, an upper global limit of about 1.3×10^5 Gw has been estimated as the total maximum extractable wind power, of which about 2,000 Gw is estimated as being available within the continental United States. At present, total DOE wind program installed and operating capacity amounts to almost 3 Mw. Although commercialization of wind energy technology does not depend upon any major technological breakthroughs, technical, and engineering developments are needed to lower the capital, maintenance, and operating costs. Current R. & D. involves the development of both small (less than 100 kw) and large (100 kw or greater) wind machines; investigating wind energy applications; evaluating national and local wind resources, and assessing problems and marketing strategies. Large wind systems may supply about 0.19 quads of energy by 1990, plus an additional 0.11 quads from small systems. Expectations for the year 2000 are for about 2.0 quads from large machines and an additional 0.32 quads from small machines.

VI. ANALYSIS AND DISCUSSION

This report has examined an extensive array of energy technologies that offer a diversity of opportunities to tap new domestic sources of energy, to increase the reserves to production ratio of our resources, or to improve the efficiency with which we process and deliver energy to the ultimate industrial or individual consumer. The picture revealed is a complex montage of quantities of energy, time elements, and private and public expenditures. In view of this complexity, the question is: where do the various research activities described in the report fit into our future energy picture?

To facilitate discussion of this question, the technologies were first grouped according to the primary form of the original source of energy, e.g., coal-based, direct sunlight, fluid hydrocarbon, and so forth. Consideration was then given to the quantity of energy in customary units, tons, barrels, kilowatts, or Btu's that ultimately may be available using the technology. Clearly, many of the energy resources and their technologies are already part of the Nation's developed energy capability: consideration was therefore given to what portion of the resource potential is currently developed either in terms of capacity (for flow resources) or as known reserves (for depletable resources). Considerable attention was then given to various estimates that have been made as to the level of energy output that might be anticipated in the years 1990 and 2000, based upon the research, development, demonstration, and commercialization now being undertaken or contemplated. Finally, the various technologies were considered in terms of the relative level of federally supported R.D. & D. that might be required to bring them to the levels of contribution to U.S. energy needs variously predicted for them within the time frames indicated above.

Considered in this way, two kinds of technology "exceptions" became evident: first, those that are not believed likely to represent commercially-viable energy options by the year 2000; and, second, those which—for various reasons—probably will not receive significant future Federal R.D. & D. support. These two categories of technologies are indicated below:

I. *Little or no anticipated contribution prior to 2000 but requiring Federal support*—

Breeder reactor,
Fusion,
Hydrogen, and
Satellite power stations.

II. *Significant contribution by 2000 anticipated but future Federal R. & D. support considered negligible*—

Cogeneration,
Conservation/efficiency, and
Passive solar.

With regard to those technologies given in I, above, it is difficult at this point to make refined economic judgments about their long-run potential, and at best their future contributions will result from research that, for the most part, takes us past the year 2000. Hence, assessment of the potential contributions of these four technologies was considered outside the time frame of the present report.

With regard to those technologies given in II, above, the need for Federal R. & D. would appear to be negligible or non-existent; rather, the situation would seem to require private investment of time and money to determine on an operational basis whether the possibility for improving the efficiency of their supply or delivery systems in a certain way will prove economically attractive and reasonably reliable. Thus, the question appears not so much one of research, but whether an individual or a firm will be sufficiently attracted to try these approaches, i.e., in all of these cases, the introduction and evolutionary refinement of the technologies would appear to require the normal involvement of manufacturers, producers, and consumers, rather than the expenditure of Federal R. & D. funds. Hence, the assessment of the potential contributions of these technologies was not considered germane to this report.

It should be emphasized that the above comments concerning the technologies included in I and II, above, in no way represent a dismissal or downgrading of the potential contribution these technologies might make to future U.S. energy supplies. Continued Federal R.D. & D. support may well be justified for technologies given in I, and continued private-sector support may be forthcoming for technologies given in II. No judgment of the merits of such support, either Federal or private, is intended here. Further, it should be noted that, were policies adopted to further their rapid deployment, some of the technologies now placed in Category I—especially the breeder reactor—might well be treated instead under Category III, discussed below.

The remaining 23 technologies were then grouped—as shown in the following table—according to whether their estimated energy returns by the year 2000 were likely to be large, moderate, or small for a limited, moderate, or extensive Federal investment. These estimates of both possible energy returns and extent of Federal support are of course qualitative judgments of a somewhat arbitrary nature and simply represent a "best guess" as to what our future course of action may be, based upon the information given in each of the individual technology chapters.

ESTIMATED RETURN ON INVESTMENT FOR TECHNOLOGIES REQUIRING SIGNIFICANT FEDERAL SUPPORT (CATEGORY III)

Estimated return	Extent of Federal R.D. & D. support required		
	Limited support	Moderate support	Extensive support[1]
Large	Heavy oil Unconventional gas		
Moderate	Combined-cycle gasifier Ethanol and methanol[2] Low- and medium-Btu coal gasification Solar heating and cooling of buildings Wind energy	Advanced converter reactors Agricultural and industrial process heat applications Fluidized bed combustion Oil shale	Coal liquefaction Photovoltaic energy conversion
Small	Energy from municipal solid wastes Geothermal energy Low-head hydropower	Fuel cells	([3]) High-Btu coal gasification Magnetohydrodynamic power generation Ocean thermal energy conversion Solar thermal power conversion

[1] Without extensive Federal R.D. & D. support and a commitment to commercialization by the year 2000, the technologies listed in this column might well have been placed in category I of table 13, rather than in category III.
[2] Combined mid-range estimate (see table 12). Upper estimate would place these technologies in the large-return category.
[3] Were policies to be adopted to accelerate their rapid deployment, some of the technologies now listed in category I of table 13—the breeder reactor in particular, and possibly satellite power stations—might well be listed here, instead, under category III.

Considering first the technologies listed in the table under "Limited Support", the group includes heavy oil, gas from unconventional sources, the combined-cycle gasifier, alcohol fuels (ethanol and methanol), low- and medium-Btu coal gasification, solar heating and cooling for buildings, wind energy, energy from municipal solid wastes, geothermal energy, and low-head hydropower. Several of these technologies have a number of factors in common. Quite striking is that most of them are not new—we are well along the learning curve for many of them. Drilling for oil and gas and the movement of fluids in the reservoir have been studied for many years. The production of alcohols—and especially ethanol—from a variety of raw materials, as well as their combustion in internal combustion engines, is familiar technology. We have been using wind power for centuries, and its conversion to electric power is a simple process. Although these technologies require some further research, the primary need is to demonstrate that they have commercial utility in today's energy markets. This should not involve large expenditures of Federal funds over an extended period. Substantial private sector involvement can be expected, first in research and later in product commercialization once the technology is shown to be usable. Finally, the energy sources being tapped are of appreciable size, so that the amounts of energy that each could contribute by 1990 or 2000 is significant. Thus these technologies possess all of the key factors—resource magnitude, familiar technology, potential for a competitive cost level, and good timing—that make likely the prospect of a moderate-to-large energy return for rather limited Federal support.

For several other technologies listed under "Limited Support," the key factors also tend to be mostly favorable but the combination appears less strong. For example, the combined cycle gasifier would appear to be a good prospect but has the disadvantage of not being quite as familiar a technology and may have some limits in its early applications. In contrast, low- and medium-Btu gasification are already "on-the-shelf" technologies that merely need some demonstration efforts. However, there may be restraints on the general utility of this quality of gas as an industrial fuel. Solar heating and cooling techniques are also well-known and may prove useful, but their widespread application still faces a number of institutional, rather than technological, obstacles. Solid waste conversion seems to have some favorable combinations of economic factors, but its operational feasibility in actual urban settings needs to be further established, and the total resource recovery potential has upper bounds. Geothermal heat and the use of our remaining undeveloped low-head hydropower both suffer from either the availability or usability of specific sites. Other than a lack of experience in finding and developing geothermal resources, neither of these two relatively lowgrade energy sources seem to require a "pure" research effort. Thus, although none of these technologies would appear to require more than limited Federal support, the above factors may serve to preclude more than a small-to-moderate energy return for that support.

Considering next those technologies included under "Moderate Support", we encounter technologies definitely less familiar or well-developed than are those of the above group and which for various reasons imply the need for considerably more Federal support if they are to be developed. For example, the improvement of future light water nuclear reactors involves achieving a higher performance factor in the operation of the plant and the use of the fuel charge. Better reactor design would enhance our efficient use of uranium resources as well as reduce costs. However, this kind of contribution to supply is limited both by the number of reactors that might be involved by the end of the century as well as theoretical limits to achievable uranium burn-up. Agricultural and industrial solar process heat require a definite research investment to demonstrate their usefulness, but even if proved usable there are limits on where such low grade heat will be useful. While oil shale technology is not new, it has never been tested on a commercial scale. The pace of its development, plus the large front-end expenditures, seems to suggest the need for rather deliberate progress over an extended period of time. Fluidized-bed combustion, like the combined-cycle gasifier discussed previously, also appears a good prospect but suffers the disadvantage of lack of familiarity and possible limitations in its early application. The fuel cell has a very limited potential for producing commercial energy by 2000, and the planned R. & D. funding is not very large. Thus, these "Moderate Support" technologies—although considered as potentially requiring significantly greater federal support than the "Limited Support" technologies—may, over the next two decades, at least—involve a somewhat lesser energy return.

Finally, we consider under "Extensive Support" those technologies which, if pursued, appear to require the greatest Federal support but which, at least by the year 2000, may yet provide commensurate energy returns. With one exception, the group reflects primarily the large amount of Federal R. & D. support needed to achieve future production of competitive energy. Moreover, the prior experience with these technologies, while not necessarily totally new, does not include familiarity on a large commercial scale. This is true for coal liquefaction, high-Btu gasification, photovoltaic conversion, and solar thermal conversion. In the case of magnetohydrodynamic power generation, a large amount of research is required to move the state-of-the-art from its present basic level through plant demonstration. In addition, long lead times may prevent any significant amount of energy output by 2000. Ocean thermal energy conversion is the one exception. In this case the amount of funds needed to demonstrate its feasibility is not as great as for the others in the group, but the potential contribution by 2000 would also appear to be relatively modest.

In considering the future potential of these technologies, it is obvious that in some situations a rather small amount of Federal support, coupled with an important effort by the private sector, may yield large energy rewards in the next twenty years. Also important are efficiencies that might be achieved in our supply stream that, while not actually providing new energy supplies, nonetheless make possible the use of less of our original energy resources in producing and transmitting energy to the ultimate user. Finally, some R. & D. efforts perhaps should be pursued cautiously because the requirements for Federal support may be large or expectations may turn out to have been exaggerated.

It is unlikely that any single one or combination of these technologies can satisfy all of the Nation's energy needs by 2000, no matter what the outcome of our R. & D. efforts may be. Hence, a variety of efforts will no doubt continue to be required. Thus, it would appear most likely that much of the familiar resource/systems pattern that currently supplies the bulk of our raw energy supplies will still remain visible as we enter the next century.

INTRODUCTION *

I. Purpose and Basis of the Study

The American people and the Congress have always had great confidence that the engineering and scientific capabilities of the United States can rescue the Nation from threats to national security or to the general economic welfare. While this faith has frequently been rewarded by remarkable achievements in the past, it is still recognized that the process of research and development is difficult to manage. Goals are not always achieved, results are not always predictable, and the price tag can be large. Given these conditions, normal prudence demands a careful review by Congress of current research and development (R. & D.) investments regarding how they might provide more future domestic energy, keep costs down or achieve greater technological efficiency. While we may now be prepared to accept the high costs and uncertainties of energy research, there is still a need to leaven our national mix of R. & D. ingredients with some forethought as to the best strategy to be employed. In essence, we should attempt to array governmental support of R. & D. in a manner that is most likely to enhance and replenish our energy supplies while minimizing our total research effort and remaining sensitive to environmental degradation.

Energy is not only ubiquitous, it can be captured, transported, and eventually used in a variety of ways. This provides us with a large menu of energy choices. This study attempts to identify among the various energy supply opportunities, the various respective expectations for contributing to the future U.S. energy situation. As much as knowledge permits, the focus of our attention is on the specifics of relative cost and timing. There is a variety of costs to consider beyond merely the invention of a new technology. There is also the cost of developing and testing the more promising new technologies at scales that approximate commercial activity. Finally there is the cost of introducing a new commercial technology into the main stream of American energy production and use. The duration of this sequence varies in length, and each technology is situated differently.

Any major departure from past energy practices that can significantly increase the domestic supply of energy or reduce the energy inputs required by the U.S. economic system is likely to require research and development programs measured in decades. Therefore, the years 1990 and 2000 have been chosen as break points along the way from how we currently supply ourselves with energy toward that time when measurable changes resulting from research already well along toward actual employment can be expected. Looking beyond 2000, we also examine those less mature tech-

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nologies that may make a difference in the next century. For these, the objective has been merely to identify the resource opportunity plus the kind of basic research that is underway or needed now if the option is to be pursued.

The threshold question of what promises to have important enough impact on the U.S. energy supply stream in this century to justify current major research expenditures from Federal funds is a crucial one. From an array of choices, we need to select and concentrate on a manageable number of alternatives. This objective is to avoid continuing expenditure of time and public funds in examining and pursuing with equal vigor all of the many energy alternatives when only a few are likely to make major contributions as a return on the Federal R. & D. investments. The relative attractiveness of each new technology should be to a considerable degree a reflection of both the level of expectation for adding to U.S. domestic energy production (or reducing the amount of primary energy input required) and the Federal support now considered needed to make that occur. Obviously, given the judgmental nature of the exercise, it is important to strike a happy medium between the optimism and pessimism that accompany all evaluations of new technologies.

One important constraint has been placed on the scope of this study. Only those R. & D. opportunities that relate to the extraction, production, processing, transport, and conversion of energy between source and the terminal user of energy are examined. The intent is to restrict the investigation to examining how we can improve the supply side of our domestic energy equation. This emphasis recognizes the essential difference between: producing and consuming technologies; the economic motives at work; and the means of effecting the technology transfer. Thus, in this report conservation of energy is treated as it relates to the search for greater efficiency in producing, transporting, and processing energy rather than addressing such issues as how R. & D. might reduce residential consumption of fuel oil or improve automotive performance. To illustrate further, fuel cell research to develop units for producing electricity in individual residences is within the purview of this study, but the search for new building materials to reduce heating costs is not. This important parallel question of the most effective use of public expenditures on research for improving energy consumption needs to be examined independently. In separating these R. & D. tracks we are not minimizing the importance of conservation in use as a particularly effective strategy in the very near term as well as its importance over all future periods.

It was recognized that a detailed assessment of a large number of technologies would be long and costly. Hence, the analysis here has drawn primarily upon the existing expertise of the current staff of the Congressional Research Service augmented by what the staff would readily draw out of the extensive literature on energy supply technology. We must also acknowledge that results are not only to an appreciable extent judgmental in character but must deal in orders of magnitude rather than precise measures of future supply potential versus research costs. These uncertainties about feasibility, support, requirements, or rewards have been identified.

Given these caveats, the report provides a general view of the research, development, and demonstration terrain that lies ahead, some sense of the difficulties that may be encountered in crossing it, and a rough estimate of the magnitude of the eventual energy yields over a future time period that has some meaning in terms of our now-foreseeable energy problems. The problem we seek to resolve is the direction and kinds of activities that are needed today if we are to have reasonable expectations of an improved energy situation ten to twenty years hence.

II. Today's Perspective of Tomorrow's Energy Problems

A. The Policy Issues at Hand

A capsule review of the current U.S. energy supply capability is not encouraging. In 1977, U.S. coal production finally exceeded the previous record year of 1947. While this shows an improvement in our coal supply situation it should be noted that current coal mine capacity is probably less than it was immediately after World War I. The U.S. rate of discovery of new oil and gas reserves declined after the early 1960's, leading to the eventual peaking of crude oil production in 1970 and of natural gas in 1973. However it is still likely that we have not as yet passed the mid-point in our discoverable, but producible at higher cost, oil and gas resources. In the non-fossil energy categories, hydroelectric power passed its zenith of relative importance long ago, and nuclear power remains well short of past ambitious expectations.

Turning to the development of alternative sources of energy, the performance to date offers little reassurance. We have on hand: one geothermal plant; no commercial-scale oil shale plants; no pipeline quality coal gasification facilities; no commercial experience in the liquefaction of coal; no tidal power plants; some limited small-scale direct or passive solar heating; some demonstration activities in energy production from wind, biomass, and solid waste; and limited experience in low- and medium-Btu coal gasification, heat pumps, fuel cells, and combined cycle or co-generation of electricity. New departures in conventional nuclear plant design, breeder reactors, nuclear fusion, and magnetohydrodynamics in our central station power plants appear to be well in the future.

The recent frustration of innovation in supplying the United States with energy is a striking departure for a nation that in the past drilled the first oil well, designed continuous coal mining machines, introduced long distance gas pipelines, mounted a joint private and public effort to build the Shippingport nuclear reactor, and first ventured into deep water with its drilling platforms. Only three decades ago, the United States consumed approximately half of the world's fossil fuel production, but it produced virtually all of that domestically. While we may be concerned about our energy consumption habits, they were not learned at the expense of the rest of the world. Even 20 years ago the United States was still producing 94 percent of its own energy. Today domestic capability has slipped to 80 percent of current consumption and continues to drop.

Energy import dependency is not necessarily of itself fatal. Other nations are more dependent upon energy imports, and the United

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States itself has never been self-sufficient in many of its resource needs. The policy problem stems from the rapidity with which this domestic (and world) limitation of energy capability has descended upon us and the concurrent appearance of a petroleum producers' cartel. We no longer possess the international economic and political independence that was once ours. At the margin, our incremental additions to energy supply in recent years have usually been imported oil. That oil has become very costly per Btu and will remain so. Most of the world's oil exporting nations have become dedicated to prolonging the life span of what may be their only major resource endowment as well as to maximizing their revenues at a stable level of real annual income. These economic goals when combined with their small size and political volatility prompt serious concern about U.S. energy supply security.

In past times of economic or military stress, the world energy supply situation was cushioned by a diversity of energy sources—European coal, Western hemisphere oil, or idle U.S. capacity for producing either coal or oil. At present, if any uncommitted or surplus world energy capacity remains available in the short term, it is located in a few oil producing nations of the Middle East. As a consequence U.S. response to either emergency conditions or to producer-set prices for energy is severely restricted. The energy supply capability at our disposal when the Suez crisis struck in 1956 no longer exists. In addition we for the first time must operate frequently in a non-competitive, sellers market in world energy.

If the Congress seeks to correct this situation with dispatch, it faces an array of obstacles. One is time—time to decide on direction, time to legislate, time to implement, time to experiment, time to build—efforts measured in years and decades. Even the simple goal of creating an emergency crude oil stockpile is elusive—how much to spend, what quantity of oil, where to place it, how to store such a large quantity of crude, and how to acquire it given the market conditions.

Measures to enhance domestic supply and the use of public funds for R. & D. have been and are being considered at a time of legislative concern and action resulting from the large cash flows that are being generated within energy producing companies as a result of the escalation in the world price of crude oil. While high prices should simultaneously encourage more domestic supply and consumer conservation, there is a real concern that cash surpluses in the hands of the producers may not necessarily be used to serve the greatest public interest. If U.S. prices are held down by government action, profits would shrink and consumers would avoid an inflationary shock. But then what substitute stimulus can be found to provide motivation for conservation and for investment in new, risky and costly supply ventures? Moreover, if we do not find a domestic supply response we face an ever enlarging energy deficit in our balance of payments. Delay also means further inflation in the costs of research and the capital investments required to construct domestic supply facilities.

Perhaps the most debilitating aspect of any aggressive domestic energy supply program is that it will probably run counter to many other national pressures and programs. Our remaining domestic fossil fuels or our other alternative domestic energy resources will probably be more costly than imports, placing a new burden especially on the lower-income segment of the populace. Large infusions of Federal funds run counter to the current desires to control inflation and to limit or cut the expanded cost of government. We are also reluctant to turn our backs on over ten years of effort that has been expended toward providing for the procedural needs and meeting the costs of environmental protection.

Many are confident that the price stimulus of the market place without government controls will bring to both energy producers and consumers the motivation needed to simultaneously reduce consumption and replenish our domestic supplies. After all there have been energy dislocations and doubling or tripling of energy prices in our past history. Those conditions vanished after a few years. But our past experiences are not good models of the economic and world supply conditions that now exist. So turning loose the market forces to correct the situation is hard to accept with confidence, particularly since the supply response is uncertain and the adjustment period is likely to be much longer than in past circumstances.

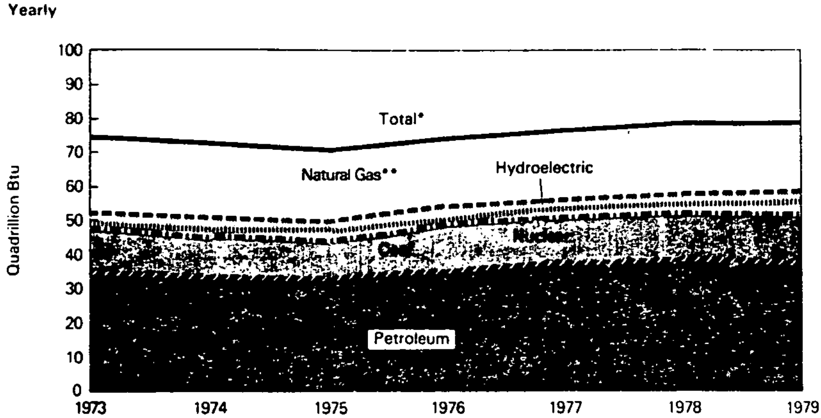
But to suggest that we administer and regulate our way out of the difficulty by substituting the Government for the market place offers its own risks, costs, and impacts. History provides some reservations about the effectiveness of centralized control of complex economic systems. Nor are there clear exit routes for Government once the difficulties have been overcome. "Buying" a solution is a fairly common 20th Century strategy, but there is the question of whether we can afford the price this time. Government involvement does not eliminate the uncertainty in our energy situation, and it might increase the cost of the eventual answer to the problem without necessarily improving the quality of the solution or cutting the time needed to reach it. There is an understandable congressional apprehension that we may now be induced to purchase a herd of energy "white elephants" requiring disposal a decade from now. Subsidies once in place are difficult to withdraw without creating adverse industrial and public impacts.

B. The Future Supply and Demand Mix of the United States

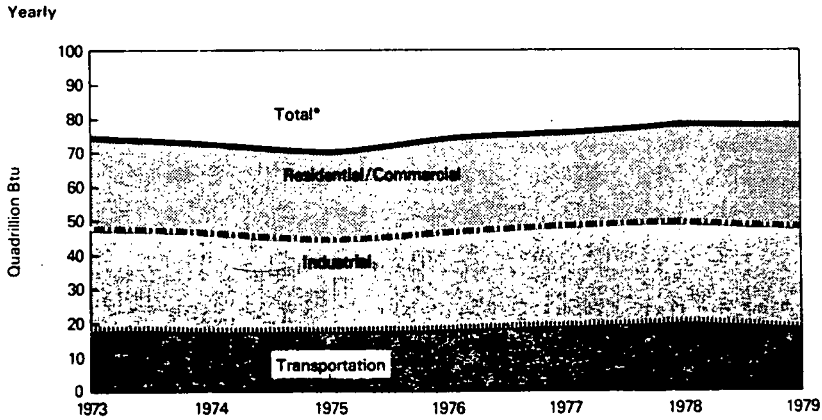
Just as there is no certainty as to the "best" pathway to enhancing our domestic supply situation, we cannot predict with precision the amount of energy the United States will actually need in the future (see figure 1). This is a reflection of more than a normal lack of confidence in energy demand forecasts. There is a strong likelihood that the United States is entering a period of significant adjustment both to higher price conditions as well as a possible functional change in the relationship between the consumption of energy and the general level of U.S. economic activity. The difficulty of analyzing our complex energy market has been compounded by a lack of experience in the response of energy consumers to high prices.

FIGURE 1 - U.S. ENERGY CONSUMPTION BY ENERGY TYPE AND END-USE SECTOR

Energy Consumption (Primary Energy Type)



Energy Consumption (End-Use Sector)



Source - U. S. Department of Energy, Energy Information Administration, Monthly Energy Review, April 1980, pages 7 and 21.

From 1920 to 1955 the relationship between total Btu's consumed and the U.S. gross national product was fairly predictable: both were increasing steadily as the economy expanded, but energy somewhat less rapidly. The explanation for the slow decline in the energy/GNP ratio was quite simple: many users were becoming more efficient, some expensive parts of the economy were not as energy intensive, and the progressive shift from coal to oil and gas reduced our expenditures on primary energy. But from 1955 to 1975, the ratio between energy and GNP stabilized rather than continuing its steady decline.

Sixty years of observing the coincidence in fluctuations and general trends in energy and the economy provides a strong basis for forecasters to assume that energy is intimately linked with our industrial economy and vice versa. But today it has become apparent that the almost one-to-one relationship since 1955 should not be viewed as a permanent fixture. One must recall the sharp change in direction in 1920 that preceded the steady trend from 1920 to 1955. Thus, we now find ourselves in the position of knowing that while energy and the economy are linked, that coupling is a flexible one. Yet few of those who have studied the problem are willing to profess sufficient understanding of the mutual interaction of energy and the economy to make a rigorous forecast of the degree and timing of the change we are likely to experience between now and 2000. Some may claim that energy can be "decoupled" from the economy, but this seems either naive or is a misleading descriptor for the rearrangement of linkage.

Within a forecast of future U.S. energy consumption we must deal with the components of demand. The electrical sector is particularly important when assessing the various types of R. & D. strategies. However, electric power forecasts have become more difficult in recent years. There has been a well established trend in the United States for a persistent shift toward greater reliance on electric power. This reflects consumer and industrial preference for its efficiency, flexibility, and cleanliness. In addition utility marketing, financing, and rate regulation characteristically tended to encourage the continuous expansion of capacity by these natural monopolies. In the past, these circumstances led to expansive forecasts of future electric power requirements. These forecasts in turn became self-fulfilling prophecies as the resulting new capacity provided a stimulus for a search for new markets. Unfortunately, regulation of energy utilities, traditionally based primarily on a return on capital investment, was not designed for seeking out the lowest cost energy to meet national needs. More recently the drastic change in primary energy prices, reduction in demand, changes in the regulatory process, and a lower pace in generating capacity expansion have significantly altered the growth outlook in electricity. Thus, the future primary energy needed for conversion to electricity will likely be less than previously anticipated, but we have a limited historical basis for forecasting how much. Nonetheless, the relative importance of electricity for final consumption should continue to grow.

Constantly changing energy circumstances, particularly the oil import price, explain why the 1979 report to Congress by the Department of Energy's Energy Information Administration (EIA) presents three basic projections for the total demand for energy in the United States in 1990. The projections reveal that in 1990 the total use of energy in the United States is expected to vary from a low of 88 quadrillion Btu's to a high of 93 quadrillion. It should be noted that in using energy demand forecasts the origin of the forecasts may be less important than the vintage. Most forecasters—private and government—have moved their projections to lower energy demand levels in recent years, as we have gained a better appreciation of the impact of prices. We are still learning about the real potential for conservation by individual consumers as well as the impact of greater efficiency in industry.[1]

In their mid-price projection, EIA indicates a diminishing share of energy used in residences by 1990, a similar downward trend in commercial consumption an increase in industrial use from 36 percent (1978) to 42 percent, and a drop in transportation requirements. The greatest change is anticipated in the share of primary energy charged to conversion and transmission losses by the electric utilities. This is projected to increase from 21 percent in 1978 to 28 percent in 1990.

The EIA's long-term projections beyond 1995, indicate possible consumption between 108 and 117 quadrillion Btu's by 2000 and 147 to 149 by 2020. These projections also are consistent as totals with other authorities cited by EIA.[2] The major differences are found in the projections for individual forms of energy and consumption sectors. The proportions of residential, commercial, and transportation use of energy are shown by EIA continuing to decline while energy consumed in industrial use and fuel conversion losses are predicted to continue to increase through 2020.

By 1990, EIA expects that domestic production could vary between 77 and 80 quadrillion Btu's. Under various mixes of domestic supply and domestic demand, reflecting different assumptions of price conditions, the resulting net energy import requirement falls between 7.6 quadrillion Btu's (3.6 million barrels a day of oil equivalent) and 16.0 quadrillion Btu's (7.5 MBD). In the worst case, the net energy import share would still be reduced to 17 percent of U.S. energy consumption compared to 22 percent in 1978. Comparison by EIA of their results with non-government efforts indicated that, in contrast, private firms tend to be less optimistic about domestic production. The differences in demand forecasts are less striking.

Obviously, it is unwise to rely upon a single set of projections, or one source of data, for a perception of the future U.S. supply and demand for energy. It can be even more deceptive if separate projections of supply and demand are obtained from different sources and then used together. They are rarely linked to one another by compatible assumptions about price, technology, and the state of the economy. Indiscriminate choice of data can produce results as varied as net energy imports dropping sharply or in-

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[1] For the purposes of this report general patterns and trends are more important than the numbers themselves. The EIA annual report has been used as representative of energy studies in general and provides an internally consistent set of data. Energy Information Administration, annual report to Congress 1979, vol. 3, DOE/EIA-0173 (79)/3.

[2] Comparisons are made with Pace Co., Data Resources, Inc., Exxon, and the National Academy of Sciences projections.

creasingly between now and 1990. The support for either extreme is quite weak.

The most rational posture concerning future energy supply and demand is to assume that as the real price of energy increases it will tend to simultaneously encourage supply and discourage demand. The reverse has normally been true when real prices declined. While there can be reasonable confidence about the future direction of change, this is not as true about the degree of change. We must recall that the real level of energy demand will also be a function of concurrent economic conditions, which will in turn be linked to the behavior of prices in general. A precise, quantitative forecast of future energy production and consumption reflecting all of these variables is beyond our capability.

Thus, the potential for either very narrow or very wide spreads between domestic demand and domestic energy production in the immediate future should be tempered to some extent by the behavior of the general economy. Analytically, it is important to avoid U.S. energy supply and demand as a rigid economic process that foreordains a predictable domestic energy deficit to be reached at a given year in the future. Rather, we must recognize that the very conditions that appear to be causing current shortages may also generate other forces and reactions which may reduce a deficit now anticipated by the end of the period covered by the forecast. Unfortunately, there is never a guarantee that this will actually occur or that the deficit will not appear.

C. Resource Opportunities Versus Resource Needs

Before examining R. & D. as applied to specific energy resources, it is useful to generalize about the nature of our needs and the characteristics of the energy resources at our disposal. Energy is used for three basic purposes: to provide environmental protection and comfort, to process or transform materials, or to do work for us. The energy form chosen is usually matched to the energy use. Thus one kind of energy suitable for generating steam may not be useful for propelling an airplane or may be unattractive to the householder. It is more than a question of physical compatibility, since the final delivery costs and potential uses of energy are also affected by the way nature provides the energy. A diffuse, low-temperature energy source will be used in an entirely different way than a compact bundle of energy capable of yielding very high temperatures. All energy is initially provided as a free good by nature. The key variables are the costs of capture, conversion to a useful form, and final delivery.

The production of electricity now consumes approximately 30 percent of U.S. primary energy deliveries. There is a general consensus that this proportion will grow, perhaps reaching 50 percent by 2000. Electricity has an advantage in that it can be generated from both low and high temperature sources or from moving fluids. At the consuming point it can be used efficiently for comfort, process, or work purposes. The all-electric economy faces one serious physical drawback: the lack of mobility of the equipment used to generate the power. In addition, it is still costly to transport electric power over long distances or to deliver it in small packages at isolated locations. Certainly for the next decade, and most likely for several more, alternate energy sources that seem best suited for the generation of electricity are not likely to help us meet our need for low-cost, mobile packages of concentrated energy. This is true for much of the energy that may come initially from renewable sources.

Electricity can be used as a source of heat or to provide high temperatures for process purposes, but this always raises an efficiency question of whether we have converted heat to electricity and then back again at a needless cost of both dollars and energy. As a consequence, the direct use of primary fuels has received preferential treatment in many industrial uses and for most of our space heating. Summing up, we find that most of our transportation sector and a significant proportion of our residential, commercial, and industrial energy needs for some time to come are not likely to be compatible with certain primary energy sources that are currently most likely to be delivered as electricity.

In the past, the great natural advantage of the fossil and mineral fuels and prime hydroelectric power sites has been the large amount of energy concentrated at a single source point. Their present popularity reflects the fact that the amount of effort or cost required to gather and produce their contained energy in usable form has been relatively small compared to other potential sources of energy. The total, and frequently the incremental cost, of energy from these currently preferred sources can be extremely low, particularly if environmental threats and costs are ignored. In contrast, most forms of solar energy, either direct or derived, normally display some combination of variability, dispersion, or low intensity. Also the resource potential of these energy forms must be measured as annual flows rather than assessed as fixed, total resource endowments as is customary with the depletable fuels. Nonetheless, there is a parallel between renewable and non-renewable resources in that only a part of the annual flow or of the fixed endowment is "discoverable" and recoverable. For example, the total energy present in the atmospheric circulation above the United States is vast, but much of that energy may prove as costly or difficult to recover as the oil in an abandoned reservoir or the kerogen found in a low quality oil shale.

Despite man's long history of using organic substances for energy, both fossil and of recent origin, there still remain extensive opportunities for R. & D. to devise new and better ways of converting this material from its raw form to the most useful forms for final consumption—solid, liquid, or gaseous. Our potential supply of organic raw materials is large enough to satisfy our entire national energy requirements if we can put it to effective use.

Man has also employed the fluid flows of wind, surface water, and the tides to his advantage since pre-historic times. The mechanical use of these energy forms has proved less useful in modern industrial societies. But, within their natural limits, they still provide an opportunity to generate additional supplies of electric power.

The direct use of natural terrestrial or solar heat commands obvious attention. However, our knowledge and experience in using the recoverable portion of the natural heat of the energy of the earth and oceans is still immature. The rays of the sun are our most accessible and largest energy source if we can learn how to adjust to the physical and economic characteristics of solar energy. While the immediate use of solar energy will favor lower temperature applications, we have some past experience and current experimentation at higher temperatures. It is to be expected that in the longer term we will see the sun providing higher temperatures for process heat and the generation of electricity.

It is important that our energy research mix not exclude seeking improvements to be made in our existing energy system and the conventional sources it currently relies upon. We can make some moderate gains by improving our performance using heat now wasted. There is a need to investigate new or better ways to produce power: combined cycles, fuel cells, solar installations, magnetohydrodynamics, and new departures in nuclear reactors. Once primary energy is extracted from its source, we can improve the transportation of energy in its various forms. Finally, we cannot forget the undiscovered oil and gas of the United States or the billions of barrels, trillions of cubic feet, and trillions of tons of fossil fuels known but unproduced or left behind from past production.

The research challenge we face is how to choose from these many pathways the best route that both recognizes how we use energy now and might use it in the future. We cannot in answering this challenge expect to do it without risk, and we must proceed in the face of considerable uncertainty. Moreover, there has to be a sharpening of our attention to the political decisions that must be made if we are to improve our future development of new or improved supplies of fuels and energy and to determine the pace with which we want to proceed toward that goal. This has to be accomplished in terms of its relationship to such other national objectives as protection of the environment, arresting inflation, and achieving social improvements.

III. Organization of Appraisal of Energy R. & D. Opportunities

In this study 31 non-conventional areas of energy supply R. & D. have been identified and are examined in terms of the future energy that could be obtained from domestic sources beyond that which our current projections indicate we would produce if we merely followed our recent pattern of development. The 31 areas have been clustered into 8 related groups as follows: coal-based, direct sunlight, fluid hydrocarbons, organic conversion, nuclear, system efficiency, and other sources. The discussion of each area includes a survey of the current situation, an examination of the resource potential, a summary of the R. & D. effort being made, and an identification of what will be required in time and effort to move each energy supply technology beyond its present pattern of development. In addition to quantifying the additional energy to be expected in the time intervals specified, the obstacles and uncertainties that are likely to be encountered are discussed. For completeness, background information has been given for the major conventional energy sources that now supply the bulk of the nation's current energy needs.

Obviously even in a highly condensed format, this provides a vast array of technical description and analysis of the state-of-the-art of energy supply both present and future. This is further complicated by the variations in the amount of energy that results, the level of effort being expended, and the timing of the results. Finally, there is the recognition that energy research and its funding is not exclusively a Government endeavor.

The closing section of the report extracts from the various chapters 5 key pieces of information about each specific technology. These are: the amount of the total resource potential that may ultimately prove recoverable, without respect to any given time frame; the current development of that resource; the current annual output of energy; the current level of Federal R. & D. support; and the potential contribution in the years 1990 and 2000.

The final step in the summarization of energy R. & D. opportunities is an attempt to arrive at some general insights about the role that may be played by Federal energy R. & D. over the next 20 years in terms of the relative impact of such efforts on enlarging U.S. energy supply during those years. This exercise does not account for private R. & D. investments, and does not include supply returns beyond 2000. This does not minimize the importance of private action efforts or the value of research to provide additional energy in the longer term, but merely reflects the prime focus of the study on how Federal energy R. & D. can make a difference during the critical period from now until the end of the century.

CONVENTIONAL ENERGY SOURCES *

COAL*

I. Survey of the Current Situation

A. Description of the Technology

Coal is burned to produce heat, which in turn is used to generate steam for process heat or the production of electricity. Alternatively the heat may be used directly in industrial process systems or space heating. Coal is mined by two general methods, surface or underground, depending on the geological conditions. For each method a number of mining techniques are practiced. These techniques are discussed below, as are preparation and utilization technologies.

1. SURFACE MINING

Surface mining involves exposure of the coal seam by removal of overlying soil and rocks (overburden). The four basic types of surface mining are: area (strip), open-pit, contour, and auger mining. At present, depending on the nature and structure of the overburden, coal can be economically recovered within 150 feet of the surface, even when the overburden to seam thickness ratio is as much as 30:1. Area mining involves the development of large open pits in a series of long narrow strips (usually about 100 feet wide by a mile or more in length). It is the preferred method in flat terrain where the coal seam is parallel to the surface, as it is for many Western coals. Open-pit mining is similar except that it involves the preparation of a larger area, perhaps 1,000 by 2,000 feet wide, exclusive of areas where thick seams are available. Contour mining is most commonly practiced where deposits outcrop from rolling hills or mountains, as in Appalachia. This method is to remove the overburden above the bed by starting at the outcrop and to proceed along the contour of the bed creating a shelf or "bench" in the hillside. The usual procedure is to contour mine as far into the hill as practical, then auger further. In auger mining, huge drills, with cutting heads up to 7 feet, are driven horizontally up to 200 feet into the coal seam.

Surface mining equipment ranges from ordinary bulldozers and front-end loaders to huge power shovels and draglines that are among the largest moving land machines in the world. Some power shovels have bucket capacities large enough to fill about 4 train cars. Surface mining generally yields 85 to 90 percent coal recovery.

* Prepared by James E. Mielke, specialist in marine and earth sciences.

2. UNDERGROUND MINING

Underground mining is considerably more complex than surface mining. Most underground coal mines in the United States use room and pillar mine development of which there are two main types, conventional mining and continuous mining. Conventional mining technology involves the sequential use of undercutting, drilling, loading and roof bolting machines. Continuous mining combines the operations of conventional mining into one machine which tears the coal from the seam with revolving teeth and loads it for transport out of the mine. In general, room and pillar methods are limited to about 50 to 60 percent coal recovery.

A third method of mining, longwall mining, accounts for only four percent of the coal mined underground in the United States, but is extensively used in European coal mines. Longwall mining utilizes a steel plow or rotating cutting drum which moves back and forth across a face that is several hundred feet long to cut the coal, which then falls onto a conveyor. A series of large self-advancing hydraulic jacks, topped with broad steel beams and set a few feet apart, support the roof and protect the machine operator. After each pass of the machine along the coal face (350–600 feet long), the support jacks momentarily release their pressure and move forward to resume their support, thus allowing (if desired) the roof to collapse over the mined out area. By eliminating the need for pillars, recovery rates of 95 percent are not uncommon.[1] A fourth type of underground mining called short wall mining is also used, especially where the coal bed thickness is variable. Overall coal recovery from short wall mining is about 85 percent of the coal seam.

3. COAL PREPARATION

Coal preparation modifies the mined coal to help meet the customers' needs in terms of size, moisture, and removal of rock and mineral impurities. A preparation plant of some sort is an integral part of most large mines and may often serve a number of mines. A typical preparation plant includes crushing, sizing, cleaning to remove impurities (often using density separation in water or other medium), dewatering and drying, and process water clean-up.

4. FLUE GAS DESULFURIZATION

Flue gas desulfurization is also an integral part of conventional coal utilization. The basic technology involves devices called scrubbers which remove SO_x in a liquid containing chemical absorbants such as lime, limestone, magnesium oxide, sodium carbonate, alkali flyash, and ammonium.[2] The processes are further characterized as throwaway or regenerative. Regenerative processes recover the absorbant and generally produces a marketable product such as elemental sulfur of sulfuric acid. Currently the predomonant technology is throwaway lime-limestone scrubbing.

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[1] U.S. Congress. Senate. Committee on Governmental Affairs. Permanent Subcommittee on Investigations. "The Coal Industry: Problems and Prospects." Committee Print. 95th Congress, 2d session U.S. Government Printing Office, Washington, December 1978, p. 26.

[2] Office of Technology Assessment. "The Direct Use of Coal." U.S. Government Printing Office, Washington, 1979, p. 96.

B. Known Resource and Reserves

The coal reserves of the United States total approximately 437 billion short tons. However, due to economic, technological, safety, and other considerations, not all of the coal in a particular deposit can be extracted. The recoverable reserves are estimated to total 283 billion tons, based on 57 percent recovery in underground mines and 90 percent in surface mines. These estimates for recoverable reserves are based on deposits no deeper than 1,000 feet and seams at least 28 inches thick if they are to be mined underground, or with depth to seam thickness ratios of 10:1 or less for surface mines. Identified U.S. coal resources are postulated to be more than 1,700 billion tons.[3]

C. Current Contribution to U.S. Energy Supplies

Coal represents about 90 percent of the U.S. fossil fuel reserves yet it currently contributres around 20 percent of U.S. energy needs. At current consumption rates these reserves would last about 370 years. Coal production in the U.S. had been in a slump since 1947 when 687 million tons were produced (630 million tons bituminous plus 57 million tons anthracite). This level was not surpassed until 1977 by which time anthracite production accounted for less than 6 million tons. In 1979 production totaled about 770 million tons, over 100 million tons above the 1978 level. However, 1978 data reflect a three-month strike by the United Mine Workers. Underground mining now supplies less than 40 percent of the coal produced in the United States while surface mine production has been increasing.

D. State-of-the-Art

Although the direct use of coal in the utility, industrial, commercial and residential sectors is commercially viable using current technology, there are constraints which may limit its increased use. The major factors influencing the design of combustion facilities are the size of the unit, the type of coal to be burned, and the environmental standards which must be met. It is difficult to switch from one coal to another having different characteristics. The technology developed for the utility sector is often inappropriate for the industrial or commercial installation. New technologies for extracting, transporting, cleaning, upgrading, and burning coal are continuously emerging, as are environmental controls for every phase. However, in the mining sector, improvements in technology are slow to become widely used and are likely to be introduced only in new mines or when older equipment is no longer serviceable.

E. Current Research and Development

The Department of Energy (DOE) conventional coal utilization research program emphasizes a short to mid-term thrust aimed toward development and transferring to industry the technologies necessary to increase the rate of extraction for solid fuels in order to reverse the recent negative trends in coal mining productivity.[4]

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[3] Averitt, Paul. "Coal Resources of the United States, Jan. 1, 1974," U.S. Geological Survey Bulletin 1412, 131 p.

[4] Department of Energy. Congressional Budget Request, fiscal year 1981, v. 6, p. 20.

Current efforts include completing trials of a new shaft boring machine, a tunnel boring machine, a prototype longwall shearer control system, and a high capacity longwall conveyer; fabricating and testing three continuous face haulage systems; and operating a surface test facility to simulate underground conditions for equipment testing. Development work on advanced mining systems such as the Kloswall mining system, variable wall miner, and hydraulic borehole mining is continuing. Also development of techniques for hydrotransport of underground mined coal to the surface is ongoing. Development work is continuing on a surface mine optimization model to improve efficiency in mine development.

In the area of coal preparation, research is being conducted on lignite drying, froth flotation, oil agglomeration and wet high-gradient magnetic separation techniques. Longer-term research involves chemical cleaning techniques. Combustion technology and research for materials more resistant to corrosion and attack from coal slag are also being pursued. Advanced environmental control technology relevant to direct coal utilization is another direction of current R. & D.

II. Prospects or Requirements for Further Development

A. Research and Development

1. CAPITAL

Underground coal mining in the future will probably resemble that of today even though new machinery will undoubtably be introduced.[5] A major reason for this is the tendency for mine operators to retain their machines in place as long as possible. Much of the ongoing research in coal mining technology is therefore aimed at providing short-term improvements in existing mining systems with research commonly concentrating on improvement of specific existing machines or their component parts.

Advanced coal preparation technology for removal of organic sulfur (which is not removed by mechanical cleaning processes) is in the laboratory stage of development. These processes are claimed to remove substantially all pyritic sulfur and 25 to 70 percent of the organic sulfur.[6] The research question is not whether the organic sulfur can be removed, but whether such processes can be developed to the point of being economically utilized. Cost data are still only conjectural but, at present, costs seem to be many times those associated with physical coal cleaning. The capital required for this R. & D. is also likely to be considerable before economic commercialization is achieved. The fiscal year 1981 budget request of DOE for research in this area was $11 million, with an additional $7 million to be requested from the Windfall Profits Tax. According to DOE estimates, one process, oxydesulfurization, if proven economical, could be expected in commercial use

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[5] U.S. Congress. Senate. Committee on Government Affairs. "The Coal Industry: Problems and Prospects," p. 26.

[6] Office of Technology Assessment. "The Direct Use of Coal." U.S. Government Printing Office, Washington, 1979, p. 101.

within seven to eight years.[7] However, the key is still the question of economics.

Research and development in combustion systems such as atmospheric fluidized bed, pressured fluidized bed, and other advanced combustion technology is also expensive. The DOE fiscal year 1981 budget request for combustion systems research was $68.5 million.

Flue gas cleanup R. & D. addresses the removal of pollution-causing contaminants from the stack gasses of conventional combustion units to meet environmental standards. Efforts are focused on improving and demonstrating the reliability of conventional lime/limestone scrubbers, developing second generation flue gas desulfurization technologies that avoid wet sludge disposal, and the initiation of advanced technologies for removal of NO_x, particulates, and heavy metals. The DOE fiscal year 1981 budget request in this area was $21 million. Also, R. & D. for advanced flue gas technologies is likely to require sizable amounts of capital through 1980 if the program is vigorously pursued.

2. TIME

With regard to mining R. & D. while continuous improvement can be expected, no large degree of innovative substitution of existing technology is expected in the next 25 years.[8] Advanced coal cleaning is also a long term research effort and likely would only under very fortunate circumstances be proven economic by 1990. Major improvements in flue gas desulfurization technology are not expected in the 1990 timeframe but major advances in these new technologies could be expected over a longer term.

3. MANPOWER

Skilled manpower for R. & D. in the coal industry could be a limiting factor in technological development, particularly if goals for greatly increased coal utilization are to be met.[9] Such goals frequently encompass timely development of technology for their accomplishment.

B. Demonstration

Capital needs for demonstration of new coal technologies are closely interrelated to the capital needs for R. & D. Consequently, demonstration of new mining equipment is not capital intensive provided the attendant R. & D. has resulted in construction of the prototype equipment. Demonstration of direct coal utilization would also include the software incentives provided under the DOE coal utilization program. These include preparation of planning guides and handbooks to enable potential users to evaluate their coal use applications and make comparative cost estimates, including evaluating the costs of retrofitting existing installations. The 1981 DOE budget request for these activities was $1.2 million, and

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[7] Department of Energy. Fiscal year 1981 congressional budget request, vol. 6, p. 23.

[8] U.S. Congress. Senate. "The Coal Industry: Problems and Prospects," op. cit., p. 27.

[9] U.S. Congress. House and Senate. Committee on Interstate and Foreign Commerce Committees on Energy and Natural Resources and on Commerce. "Project Interdependence: U.S. and World Energy Outlook Through 1990." 95th Congress, 1st session, Committee print. U.S. Government Printing Office, Washington, 1977, p. 244.

an additional $0.8 million was requested for related activities to increase the production and utilization of coal.

Demonstration of direct coal utilization technologies is an ongoing effort and likely to continue through 1990 as new technological developments are achieved. Manpower needs for demonstration of new direct coal utilization technologies are also tied to the R. & D. manpower needs mentioned above. Shortages of skilled scientists and engineers in this field could occur.

C. Commercialization

1. CAPITAL

New mines are very expensive to open. Costs vary from site to site depending on the nature of the deposit. A 1976 estimate (adjusted to 1979 dollars using the implicit price deflator for gross national product) gave the following results in dollars required per annual ton capacity:[10]

	Appalachia	Illinois	Western
Surface	58	62	22
Underground	82	59	59

Using these figures, a two-million ton per year surface mine in Illinois would cost $124 million. A mine this size would just meet the demand of one large electric utility unit.

Assuming all additional coal production came from new mines, to meet the goals of the revised Project Interdependence Blueprint (1,040 million tons per year by 1985 and 1,500 million tons per year by 1990) would require an investment in new mines of $19 billion at the 1976 estimate (adjusted to 1979 dollars) for surface mining of western coal. This figure would be approximately three times higher for underground mining or surface mining in Appalachia or the Midwest. Another 1976 estimate based on attaining coal production of 1,100 million tons by 1990 projected capital costs needed to open new mines and replace depleting ones at $19.6 billion ($24.3 billion in 1979 dollars) by 1990.[11]

According to benefit/cost analyses by DOE using 1985 production estimates of 900 to 1,300 million tons, savings of $20 to $33 respectively could result for each dollar invested in coal mining R. & D. However, this type of benefit/cost estimate would appear highly optimistic.

2. TIME

See discussion under capital.

3. MANPOWER

Several projections of future manpower supply and needs for increased coal utilization have been made.[12] Not all of these agree. Estimates of future manpower supply are oft^n based on linear

[10] Office of Technology Assessment, p. 77.
[11] Project Inderdependence, p. 237.
[12] Ibid., pp. 237-246.

extrapolation of current trends; however, future circumstances may shift the pattern from the present one. Under the Project Independence "Business as Usual" scenario,[13] there would be no overall manpower shortage for strip mining operations although local shortages might occur in the Gulf Coast and northern Great Plains regions. On the other hand, underground mining manpower projections indicate overall shortages. According to coal industry spokesmen, the projected supply of skilled workers, particularly supervisors and maintenance personnel, mining engineers, and technicians is not sufficient.[14] One estimate projects an increase of at least 22,000 mining engineers and technicians will be needed over the next ten years.[15]

4. REQUIRED INDUSTRIAL BASE

The existing industrial base would be adequate to supply conventional coal mining equipment, although temporary backlogs might result for very large mining equipment. However, the transportation sector would need serious attention unless solutions such as mine-mouth generation plants prove adequate.

5. MATERIAL NEEDS

Further development of materials will enhance the prospects for coal utilization although materials needs for direct coal utilization are likely to be less critical than for coal conversion.

6. ENERGY EXPENDITURE

The energy output from direct coal utilization is in considerable excess of the energy input. Improvements in mining efficiency, coal cleaning, and combustion techniques can further reduce the energy expenditures or loss.

III. Potential Obstacles to R. & D. or Technology Implementation

Among the obstacles to significantly increased coal utilization are the availability of capital, labor unrest, manpower productivity problems, evolving environmental standards which affect coal utilization, transportation and storage problems, Federal leasing policy, and equipment backlogs.

If coal utilization expands at the rate many planners envision, railroad and waterway systems, in their current state, could not handle the projected increase. Also, the production and availability of very large mining equipment might not be adequate to meet projected coal production levels.

With regard to raising the necessary capital, the capital market is extremely tight, and sufficient capital will not be forthcoming unless there is an attractive return on investment. Investment in coal is hampered by uncertainties regarding the economics of oil and gas, and environmental policies.

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[13] Federal Energy Administration. Project Independence Blueprint. U.S. Government Printing Office, Washington, D.C. November 1974.

[14] Project Interdependence, p. 244.

[15] Ibid., p. 245.

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With regard to environmental concerns, reclamation requirements, control of acid mine drainage and sediment, and surface subsidence over underground mines are all obstacles that are being overcome. However, this is being accomplished at significant economic cost, time delays, and reduction in the "minable category" of coal reserves. Furthermore, air emission standards will deny economic use of large tonnages of available coal unless more cost effective scrubbers are developed. Adverse health effects, acidic rain, and possible climatic impacts from large-scale coal combustion are concerns that also have been raised. Research is also being directed toward new uses for coal ash which would otherwise present an increased disposal problem.

Other potential obstacles to increased coal utilization include labor uncertainties, due principally to wildcat strikes (and the more predictable contract-renewal strike every three years), and manpower shortages, particularly of skilled workers. Clearly an adequately motivated work force must be developed. Coal mine productivity has declined significantly (45 percent for underground mining since 1969, 30 percent for surface mining since 1973).[16] Few employees now encourage their children to enter the mines as apprentices. This family-apprentice system at one time provided a personal relationship in the mine, and helped instill pride in being a coal miner.

Finally, Federal leasing delays will still remain an obstacle to increased coal utilization, despite passage of the Federal Coal Leasing Amendment Act in 1976.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

To accomplish either the DOE coal utilization goal of 900 to 1,300 million tons by 1985 or the revised Project Independence goal of 1,500 million tons by 1990, successful management of all major constraints would be required. In addition a full and mutually agreeable commitment by Congress and the Executive Branch for placing a national priority on expanded coal usage would have to be attained. This commitment would encompass the framework of a comprehensive energy program that would modify the effects of many disincentives caused by the numerous constraints cited. In the absence of such a program it is highly unlikely these goals can be reached. In such an event, production would more likely reach 850 to 940 million tons in 1985 and about 1,100 to 1,200 million tons in 1990.[17]

B. Contribution by 2000 or Beyond

The utilization of coal seems likely to continue to increase beyond 1990 with emphasis expected to shift toward greater liquefaction and gasification of coal to replace depleted oil and gas supplies. However, direct combustion of coal would still be expected to account for the major portion of coal usage in the early part of the next century. With increased domestic consumption, domestic

[16] Project Interdependence, p. 223.
[17] Ibid., p. 209.

coal production could be expected to range between 1.2 to 1.7 billion tons by the year 2000.

LIGHT WATER NUCLEAR REACTORS *

I. Survey of the Current Situation

A. Description of the Technology

Light water nuclear reactors (LWRs) of the type currently in operation in the United States consist of two kinds: the pressurized water reactor (PWR) and the boiling water reactor (BWR). In both, the fuel consists of long rods containing uranium oxide pellets. Two to three percent of the uranium in the pellets is the fissionable isotope, U-235, and the rest is U-238, which does not easily fission. Heat, which is produced by the fissioning of the U-235, is carried away by water which surrounds the fuel rods. The water also serves to slow down neutrons which are produced in the fission reaction. Slow neutrons are needed to cause additional U-235 atoms to fission, thus maintaining the nuclear chain reaction.

In PWRs, the water in the reactor core is under pressure in a closed loop. Heat is transferred from the pressurized water to a separate water supply in a secondary coolant system which is allowed to boil, producing steam, which drives a turbine to produce electricity. In BWR's the water in the reactor is allowed to boil and drives a turbine directly.

The future contribution of nuclear energy to U.S. energy supplies is highly dependent upon the resolution of issues relating to the fate of nuclear fuel after it leaves the reactor. Hence, the reprocessing of spent fuel and the ultimate disposal of radioactive waste products will be included in the discussions below.

B. Known Resources and Reserves

At prices up to \$50/lb, the United States has reserves of 2.5 million tons of uranium dioxide (U_3O_8) and more than 7 million tons of probable resources.[1] The DOE lists another 1.720 thousand tons in the possible and speculative categories. A much larger quantity of uranium would be available at higher prices from low grade ores. Some critics question the use of the possible and speculative estimates, but the sum of the reserves and the probable resources is generally regarded as a conservative estimate of reasonably assured uranium supplies.

A typical 1,000 megawatt LWR consumes the equivalent of about 200 tons of U_3O_8 per year. Hence, assuming no reprocessing of fuel, U.S. reserves and probable resources are sufficient to supply more than 12,000 reactor years of operation. The heat input for the electricity which could be produced from this supply of uranium using current technologies is 700 Quads.[2] Reprocessing of fuel or

*Prepared by Robert Civiak, analyst in energy technology.
[1] DOE News, No. 79-47, Apr. 25, 1979.
[2] Energy in America's Future, op. cit., p. 248.

the introduction of more fuel efficient reactors could increase this considerably.

C. Current Contribution to U.S. Energy Supplies

Sixty-nine LWRs are currently licensed for operation in the United States. Forty-two of these are PWRs and the remaining 27 are BWRs. Together they account for about 9 percent of the generating capacity of the United States. In the first half of 1979, 11.5 percent of the electricity generated in the United States was produced in nuclear power plants.[3] This is a decrease from the 12 percent produced by nuclear power in 1978, and is largely due to shutdowns to modify reactors in seismic risk areas and shutdowns relating to the Three Mile Island accident.

D. State-of-the-Art

Light water reactor technology has been fully commercialized since the early 1970s—a period which saw a rapid increase in orders for LWRs. However, since then the placing of new orders for LWRs has all but ceased. In 1973, thirty-three nuclear reactors were ordered by utilities in the United States. Since 1975, only nine new orders have been placed, and no nuclear reactors have been ordered since December 1978. Moreover, since 1975 there have been about 30 cancellations of previous orders for nuclear reactors.

Many factors not directly related to the state-of-the-art of the technology have contributed to the slowdown in the development of nuclear power. These will be discussed below. Regarding the technology, the principle questions relate to the safety of nuclear reactors and the disposal of radioactive wastes.

The technology for containing both routine radioactive emissions and accidental releases of radiation has received considerable attention from the earliest efforts to develop nuclear power to the present. Highly reliable redundant safety systems have been built into existing nuclear power plants. Although these have achieved an impressive safety record, the extremely unlikely possibility of large releases of radioactive materials capable of killing thousand of people cannot be ruled out. Hence, research, development and testing continues on ways to further improve reactor safety.

The accident at the Three Mile Island Nuclear Plant, which began on March 28, 1979, was the worst accident in the history of civilian nuclear power in the United States. Although only one or two deaths are expected to occur over the next thirty years as a result of the accident, it was a serious event and has prompted an extensive reexamination of the safety of nuclear power plants.[4] Analyses of the accident have pointed to several areas in which safety can be improved. Many of the lessons learned from the

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[3] U.S. Nuclear Regulatory Commission. Operating units status report, August 1979, NUREG 0020.

[4] Major reports on the accident include: Report of the President's Commission on the Accident at Three Mile Island. The Need for Change: The Legacy of TMI. Washington, U.S. Government Printing Office, October 1979, 201 p. (referred to as the Kemeny Commission report); Nuclear Regulatory Commission. Special Inquiry Group. Three Mile Island: A Report to the Commissioners and to the Public. (Michael Rogovin, Director), vol. 1. Washington, U.S. Government Printing Office, January 1980. 183 p.; Nuclear Regulatory Commission. Office of Nuclear Reactor Regulation. TMI-2 Lessons Learned Task Force. Final report. Washington, U.S. Government Printing Office, October 1979. 1 vol., various pagings.

Three Mile Island accident concern the selection and training of reactor operators, operating procedures, and shortcomings in the man/machine interface which make it difficult for operators to determine the condition of the reactor during an accident. Other problems which were identified included emergency preparedness and a lack of understanding of small accidents and combinations of failures. The Nuclear Regulatory Commission, the Department of Energy, and the nuclear industry have all begun to address the safety concerns identified by investigations of the accident. Changes are being instituted in the design, operation, management, and regulation of nuclear power plants. In addition, new institutions have been established and research redirected to address safety issues.[5]

During the developing years of nuclear power, the technology of radioactive waste disposal was not considered as pressing an issue as reactor safety, as wastes could be stored in temporary facilities until a permanent waste disposal technology was developed. The absense of a demonstrated method for the permanent safe disposal of radioactive wastes has since become a serious impediment to the further development of nuclear power.

The situation is now complicated by an uncertainty as to the form of waste to be disposed. It has been assumed that spent reactor fuel would be reprocessed in order to recover the substantial amounts of uranium and plutonium remaining in the fuel, so that only the wastes remaining after reprocessing would have to be disposed. However, concern that reprocessing could lead to nuclear weapons proliferation by giving developing nations or subnational organizations easier access to fissionable materials led the President in 1977 to suspend reprocessing in the United States. Hence, it may be necessary to dispose of unreprocessed spent fuel rods, rather than more concentrated reprocessed wastes.

While a safe method for the permanent disposal of the radioactive wastes remaining after reprocessing has not been demonstrated, many experts believe that the technology is known.[6] In one possible means of disposal, the waste products would first be incorporated into a solid material, such as glass, concrete or a ceramic material, and then placed in the Earth in a stable geologic formation. Salt beds have been the most extensively studied geologic formation for the disposal of wastes, but several other formations have also been considered. Research and testing have convinced some that suitable isolation of radioactive materials from the environment can be achieved by such a technique. However, lack of agreement over the best form for the waste materials and the problem of selecting a definite site for waste disposal have held up the actual demonstration of disposal techniques.

The disposal of unreprocessed spent fuel rods has also received attention. Stable geologic formations are also required for their safe disposal. It is possible that the ban on reprocessing will eventually be lifted and that it would then be desirable to recover old

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[5] Actions taken since the accident at Three Mile Island are summarized in: U.S. Congress. House. Committee on Science and Technology. Subcommittee on Energy Research and Production. Nuclear Powerplant Safety After Three Mile Island. Washington, U.S. Government Printing Office, March 1980. 74 p.

[6] Gilmore, W. R. Radioactive Waste Disposal. Park Ridge, N.J., Noyes Data Corp. 1977, 364 p.

fuel rods. Hence, methods for both retrievable and unretrievable disposal of spent fuel rods are being developed.

E. Current Research and Development

1. REACTOR SAFETY

Safety research in the United States is funded largely by the Office of Nuclear Regulatory Research of the Nuclear Regulatory Commission (NRC). Program support for nuclear regulatory research for fiscal year 1980 is $162 million, almost all of which is devoted to safety related research. In addition, nearly $30 million in supplemental funds for fiscal year 1980 have been requested for safety research in response to the accident at Three Mile Island.

The major research facilities are the Loss-of-Fluid-Test (LOFT) facility, where scale model nuclear loss-of-coolant experiments are conducted, and the Power Burst Facility (PBF), where testing is conducted to simulate overpower accidents.

Additional LWR safety research is being conducted on fuel bundles, molten fuel, pumps, reactor vessels, and piping. Computer codes are also being developed which attempt to predict and analyze the behavior of nuclear reactors and their associated systems under a variety of conditions. In addition, the Site Technology and Engineering program provides information regarding nuclear power systems subjected to extreme environmental and accidental events such as earthquakes, tornadoes, floods and collisions.

Research relating to reactor control during accident conditions, control-room display and diagnostic equipment, and quantitative risk assessment techniques has been increased in response to lessons learned from the Three Mile Island accident.

2. RADIOACTIVE WASTE DISPOSAL

The DOE has been charged by Congress with the responsibility for the demonstration of a method for the permanent disposal of high-level radioactive waste from civilian uses of nuclear power. The fiscal year 1980 appropriation for DOE's Commercial Waste Management program is $220 million. The objective of this program is to develop the technology necessary and provide facilities for the long-term management of radioactive wastes produced in the civilian sector.

The program for waste isolation provides the R. & D. for the identification of sites for repositories and for the development of the technology necessary for design, licensing and operation of a repository. Conceptual designs for the above and below ground facilities needed to accept either spent fuel or solidified high-level wastes have been developed. Characterization of sites is continuing with the goal of selecting a site at the earliest possible date after it is determined if the disposal facility is to be for reprocessed wastes or for the permanent or retrievable disposal of spent fuel rods. The

DOE believes that initial operation of a repository for commercially produced radioactive wastes could begin between 1989 and 1992.[7]

Development of methods for the immobilization of radioactive wastes by inclusion in solid materials has progressed to the point that several processes are now ready for pilot scale demonstations. However, no funds have been provided yet for these activities.

II. Prospects or Requirements for Further Development

Although sixty-nine LWRs are in commercial operation in the United States, given the present situation, further development of nuclear power may require advances in reactor safety and solution of the waste disposal problem.

A. Research and Development

1. REACTOR SAFETY

Despite an impressive safety record, there is still concern over the possibilities of a disastrous accident and continued questioning of reactor safety. The most comprehensive study to date of the safety of nuclear reactors, the Reactor Safety Study[8], commonly called the Rasmussen report, has met with widespread criticism. However, even if its results were undisputed, the absence of a general consensus as to what level of risk is acceptable suggests lack of adequate criteria for determining when reactors are safe enough. It will always be possible to improve safety through further technological development.

2. WASTE DISPOSAL

Making projections regarding the development of waste disposal facilities is difficult because of uncertainties in the kind of waste disposal facility that will ultimately be chosen, the types of geologic sites which will be considered, and the size of initial facilities.

However, DOE has made some preliminary cost estimates for waste disposal, assuming that commercial wastes will be transferred to the Government with the payment of a one-time fee, and that initially retrievable storage and ultimate disposal of spent fuel rods in a geologic repository will be provided.[9] Total government R. & D. costs in support of commercial spent fuel management through 1986 are estimated to be $560 million. These costs are expected to be recovered by the Government through the charge for spent fuel storage and disposal.

B. Demonstration

N/A.

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[7] Statement of Sheldon Meyers, Program Director, Office of Nuclear Waste Management, DOE, before the Subcommittee on Research and Production of the Committee on Science and Technology, U.S. Congress, House, Feb. 20, 1979.

[8] U.S. Nuclear Regulatory Commission. "Reactor Safety Study—An Assessment of Accident Risks in U.S. Commercial Power Plants," Washington, D.C., the U.S. Government Printing Office, October 1975. WASH-1400 (NUREG 75/014)

[9] U.S. Department of Energy. "Preliminary Estimates of the Charge for Spent-Fuel Storage and Disposal Services." Washington, D.C., U.S. Government Printing Office, July 1978, 44 p. DOE/ET-0055.

C. Commercialization

Nuclear power is already a commercial technology. However, many problems exist which may hinder further commercial expansion of nuclear power. These will be discussed in the following section.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

The chief technical barriers to increased development of nuclear energy are uncertainties about the safety of nuclear reactors and the problem of waste disposal. While some nuclear proponents believe that these are not technical problems but political ones, some opponents to the further development of nuclear energy contend that the technology of nuclear reactors is not safe and an environmentally sound permanent waste disposal method has not been demonstrated. Oppostion will remain strong and the development of nuclear energy may be hindered until problems with reactor safety are resolved and a method of waste disposal is demonstrated to be safe by a convincing body of technical evidence. It may be necessary to study a large variety of geological formations before this is accomplished, thus delaying the operation of the first waste repositories until 1995.

B. Economic

Despite calculations which show that nuclear power is 10 to 30 percent cheaper than power produced in coal-fired plants, and is projected to remain cheaper through the year 2000,[10] new nuclear plants do not appear attractive to utilities. Given the current political and regulatory climate, utilities are reluctant to commit large amounts of capital when they cannot be certain that plants will be allowed to operate. Even if they are allowed to operate, new regulations may later mandate that safety features, which increase costs, be retrofitted to plants. In addition, the actual costs of waste disposal and of decommissioning nuclear reactors are not known. These back-end costs are likely to be only a small part of the total costs of generating electricity by nuclear power. However, they remain highly uncertain until procedures are demonstrated, and could be significant if they are several times what they are currently expected to be.

In addition to these considerations, a major economic deterrent to the further development of nuclear energy is the long time delay between the decision to build a plant and the start of operation. This period is now as long as fourteen years. Much of the long delay is taken up in obtaining the required licenses for construction and operation. Such delays can cost a utility as much as $24 million per month to supply alternate power sources [11] and addi-

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[10] Several independent cost comparisons of coal and nuclear energy are summarized in Oak Ridge Associated Universities. Institute for Energy Analysis. Economic and Environmental Impacts of a U.S. Nuclear Moratorium, 1985–2010. Cambridge, MIT Press, 1979. Chapter 6, Cost comparison between coal and nuclear plants.

[11] Nuclear Outage Insurance Company ready for Clients. Nuclear Week, Jan. 3, 1980.

tional millions in interest charges. The corresponding time to bring a coal plant on line is about eight years. In the light of uncertain demand projections for electricity, a utility wanting to delay commitments to build new generation capacity could later be forced to choose a source other than nuclear if it needs to introduce new capacity rapidly.

C. Environmental

Most analysts agree that there are fewer environmental problems associated with generating electicity by nuclear energy than by the major short-term alternative, coal.[12] However, the unique nature of some environmental problems associated with nuclear energy may limit its development.

It appears that the disposal of radioactive wastes presents technical and political problems, which can be solved given sufficient time. However, it may be many years before these problems are solved. During that time the accumulation of radioactive waste products in temporary storage facilities could be judged to be an unacceptable environmental burden. Several States have already banned or restricted the building of nuclear power plants or waste storage facilities within their boundaries until the waste disposal problem is solved.

The number of deaths resulting from the generation of electricity from nuclear energy is widely, though not universally, expected to be less than those resulting from an equivalent amount of electricity generated from coal. However, the character of the risk presented by these technologies is different.[13] It is not yet and may never be possible to rule out an accident at a nuclear power plant which could result in the death of thousands of people, even though such an event appears extremely unlikely. If such an event should take place, it would very likely lead to a rapid decline of the use of nuclear power. Even without a disastrous accident ever taking place, the contemplation of such an accident could result in the placing of much more severe safety standards on nuclear power plants than exist today. Such standards could mandate the placing of all nuclear reactors underground or restrict the siting of nuclear power plants to areas considerably more remote from population centers than is now the case. These measures to protect the environment would reduce the economic viability of nuclear power.

D. Social

The most intractable problems facing nuclear power may well be the social problems. One of these problems is the polarization which has taken place between pro and anti-nuclear groups, who view each other with distrust, and constantly challenge statements made on one side or the other.

Public misunderstanding of the dangers of nuclear power is another problem. A basic fear of the unknown, the obvious connection between nuclear power and destructive bombs, and the fact that accidents leading to large disasters cannot be declared impossible,

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[12] Ramsay, William. Unpaid Costs of Electrical Energy. Baltimore, Johns Hopkins University Press, 1979, 180 p. Prepared for the National Energy Strategies Project, Resources for the Future.

[13] Ibid.

all are said to have caused some of the public to estimate the risks of nuclear energy as higher than most experts' estimates of these same risks.[14] A general distrust of the Government by nuclear opponents on nuclear issues often means that government assurances with regard to safety serve only to exacerbate fears. Whether or not these fears are justified, they represent a substantial obstacle to further development of nuclear power.

E. Political

The political future of nuclear power is highly uncertain. By September 1, 1979, at least 38 separate measures had been introduced into the 96th Congress which would directly affect the regulation of nuclear power. Several of these propose moratoria on the granting of construction or operating licenses for various periods. While Congress has not passed a nuclear moratorium, the Nuclear Regulatory Commission declared a "pause" in reactor licensing following the Three Mile Island accident. No new construction permits or full power operating licenses have been granted by the NRC since before the accident at the Three Mile Island nuclear plant, which began on March 28, 1979. Although between March and May of 1980, the NRC granted permission to load fuel and begin tests at up to 5 percent of full power to three facilities.

The politically uncertain future of nuclear power extends to the State level as well. This is most troublesome with respect to radioactive wastes. At least seven state legislatures have imposed prohibitions on the construction or expansion of local nuclear waste storage facilities or on the transport of radioactive waste into the state.

Political problems with regard to the siting of temporary Away-From-Reactor (AFR) storage facilities for nuclear wastes may present constraints on the supply of nuclear power as soon as the mid-1980s. The technology for such temporary storage is well in hand, but the governors of several States which are likely candidates for AFR facilities have indicated that they will oppose the locating of AFR facilities in their States. The AFR storage problem is discussed more fully below.

F. Other

1. EMERGENCY PLANNING

Partly in response to the Three Mile Island accident, in December 1979 the Nuclear Regulatory Commission published proposed new regulations concerning requirements for emergency response plans to be used in the case of a nuclear accident. The rulemaking procedure is not expected to be completed before June 1980. The NRC staff has recommended that all operating licenses be held up until States have adequate emergency response plans which meet the new NRC rules.[15] The NRC is also revising its criteria for siting of new power plants. According to the Director of the Office of Nuclear Reactor Regulation of NRC, these two efforts, "more than anything else, contribute to uncertainty about a date for

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[14] Slovic, P., S. Lichtenstein, and B. Fischoff. Images of disaster: Perception and Acceptance of Risks from Nuclear Power. Electric Perspectives, June–July 1979: 8–20.
[15] Remarks of Joseph Hendrie in: Nucleonics Week. Nov. 8, 1979: 9.

licensing resumption."[16] The NRC staff has proposed that the new regulations on emergency planning be applied to operating plants as well. This may lead to the shutting down or the de-rating of operating plants which cannot meet the new requirements, or which do not meet them within a designated time.

2. REACTOR OPERATIONS

The President's Commission on the Three Mile Island Accident found that, without inappropriate operator actions, the Three Mile Island accident would have been a minor event. The Commission made several recommendations aimed at improving the operations of nuclear power plants. The nuclear reactor industry has taken several steps (including the establishment of an Institution of Nuclear Power Operations which will eventually have a staff of 200 people) to improve operator training and nuclear reactor operations since the Three Mile Island accident. Nevertheless, new operating license applications may be held up and operating power plants may be shut down if the NRC determines that a utility has not taken the proper steps to insure that it can operate its nuclear plants safely.

3. TEMPORARY WASTE DISPOSAL FACILITIES

In the absence of permanent waste disposal facilities, some currently operating nuclear power plants will have to shut down, beginning in the mid-to-late 1980s, unless some AFR facilities for the temporary storage of spent fuel rods are made available. It could be possible for private firms to provide this storage; however, given the present political uncertainty with regard to waste disposal, this appears unlikely. Hence, the Government may have to provide temporary AFR storage as well as permanent disposal facilities.

The DOE estimated, in 1978,[17] that the total capital costs for government-owned AFR storage facilities sufficient to meet the demand beginning as early as 1983, and a permanent waste depository commissioned in 1988, sufficient to meet demand to the year 2000, would be about $1 billion.[18] These costs, R. & D. costs, and operating costs would be recovered by a fee for waste storage and disposal. Allowing for variations in the assumptions used in the calculation, the fee to the utilities would be from $144 to $319 per kilogram of spent fuel. This represents a cost of 0.6 to 1.3 mills per kilowatt-hour of a total electricity generating cost of about 15 to 20 mills per kilowatt-hour.

It should be remembered that these costs are only preliminary estimates. Other estimates of the costs of waste disposal are as much as three times as high.[19]

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[16] Ibid., p. 2. Remarks of Harold Denton.

[17] Preliminary Estimates of the Charge for Spent-Fuel Storage and Disposal Services. Op. cit.

[18] Since then, estimates of the earliest need for AFR storage has slipped several years and the earliest introduction date for a permanent depository has also been pushed back.

[19] U.S. Congress. House. Committee on Government Operations. Nuclear Power Costs. Hearings held Sept. 12, 13, 14, and 19, 1977. 95th Congress, 1st session. Washington, D.C., U.S. Government Printing Office, 1977. 974 p.

4. ENRICHED URANIUM SUPPLY

Another requirement for increased commercialization of nuclear power is provision for an adequate supply of enriched uranium. The Federal Government owns and operates the plants in which natural uranium is enriched to the 3 percent uranium-235 content required for LWR's. If nuclear energy is to experience substantial growth in the period beyond 1990, it will be necessary for the Government to expand its uranium enrichment facilities or provide for private enrichment facilities. Current expansion plans should provide enough enrichment capacity through 1988. Since enrichment plants can be built in less time than nuclear power plants, there would be ample time to plan for increased enrichment capacity of new orders for nuclear reactors begin to increase.

IV. POTENTIAL CONTRIBUTION TO U.S. ENERGY SUPPLIES

A. Contribution by 1990

As of January 1, 1980, operating LWRs provided about 52 Gw (Gigawatts) of electrical generating capacity. Reactors under 'construction, represented another 100 Gw. Nuclear plants representing an additional 30 Gw had pending construction permit applications, or had been ordered or announced by January 1980. In view of the 12 to 14 years needed to bring a reactor on line, the total of these three figures provides an upper limit of 182 Gw which could be available by 1990. A lower limit of 131 Gw can be established for nuclear capacity for 1990 by assuming that only reactors under construction and more than 2 percent completed will be operating by that date.

Taking into account construction and licensing delays for those reactors in the pipeline, DOE's best estimate for nuclear generating capacity for 1990 is 152 Gw.[20] This is the equivalent of 9.4 Quads of energy and represents about 9 percent of the expected total energy needs of the United States for 1990 and about 22 percent of the electricity that will be generated.[21]

The DOE low estimate for the nuclear generating capacity for 1990 is 142 Gw. A DOE survey of electrical utilities in January, 1979 determined that they expect to have a combined total of 181 Gw of nuclear generating capacity in 1990. Several other estimates of 1990 nuclear capacity, by DOE, by other Government agencies, and by private institutions, released in the past year, have all fallen between these two limits.[22]

B. Contribution by 2000 or Beyond

After 1990, the situation for nuclear energy becomes more difficult to predict, because new orders for nuclear power plants must be considered. The 1990 low estimate of 131 Gw is probably still a valid estimate to the year 2000. However, it is conceivable that some sort of moratorium on nuclear plants could reduce this number.

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[20] U.S. Dept. of Energy. Energy Information Administration. Annual report to Congress 1978, v. 3, Forecasts. Washington, U.S. Government Printing Office, 1979. DOE/EIA-0173/3.
[21] Ibid.
[22] Ibid.

Given a fair likelihood that no dramatic improvement in the stalement over nuclear power will occur in the next few years, and that the 12 to 14 years required to bring a new plant on line will remain unchanged, it is difficult to see how much more than a total of 300 Gw of nuclear generating capacity can be available by the year 2000. This is the DOE maximum estimate for that time and represents about 30 percent of the total electrical generating capacity that DOE estimates will be available at that time. This figure does not include any significant contribution from advanced reactor designs or breeder reactors.

A moderately optimistic estimate of the contribution of nuclear energy for the year 2000 is 260 Gw. This would occur if there were no drastic curtailment of the nuclear reactors which are now in the pipeline and a modest number of new orders were placed in the mid-1980's.

NATURAL GAS *

I. Survey of the Current Situation

A. Description of the Technology

Natural gas is closely related to crude oil and is formed under similar geological conditions. The decomposition of organic matter, with the aid of bacteria, in an oxygen poor environment results in the formation of methane and other hydrocarbons. Natural gas (mostly methane) is often dissolved in oil at the high pressures existing in the reservoir (associated gas) and is separated from the oil after extraction from the well. It also can be obtained from gas wells drilled into reservoirs which contain natural gas but no oil (non-associated gas); and from reservoirs in which the gas occurs above the oil, but is not dissolved in it (associated gas).

The search for natural gas closely parallels the search for oil. Structures are identified by subsurface geology and geophysics and tested by drilling with rotary rigs (either on or offshore). In the case of gas, however, pipelines are necessary to transport the gas to market, although in some cases the gas can be liquefied and transported in special tankers.

The production of conventional natural gas is much more efficient than the production of oil. Depending upon reservoir permeability, recovery can be as high as 75 to 80 percent of the original in place gas.

B. Known Resources and Reserves

Proved reserves of domestic natural gas totaled 194.9 trillion cubic feet at the end of 1979 compared to 200.3 trillion cubic feet at the end of 1978, which in turn was 8.6 trillion cubic feet less than at the end of 1977 (see Table 1).[1] The drop in natural gas reserves marked the ninth consecutive year of domestic gas reserves decline, beginning at the end of 1970 when gas reserves stood at 290.7 trillion cubic feet.

Inferred gas reserves are those reserves, in addition to proved reserves, which eventually should be added to proved reserves through extensions, revisions, and new producing zones in known fields. Inferred reserves have been estimated by the U.S. Geological Survey at 201.5 trillion cubic feet.[2]

The U.S. Geological Survey, at the end of 1974, estimated domestic undiscovered recoverable gas reserves as ranging from about 322 to 655 trillion cubic feet (the low value the quantity associated with a 95 percent probability that there is at least this amount and the high value associated with a 5 percent probability of occur-

*Prepared by Joseph P. Riva, Jr., specialist in earth sciences.

[1] Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of Dec. 31, 1978. American Gas Association, vol. 33, June 1979, p. 117, and American Gas Association News Release, May 5, 1980.

[2] Miller, Betty M. et. al. Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States. Geological Survey Circular 725, p. 31.

rence).[3] The statistical means was estimated to be about 484 trillion cubic feet.[4] Since the end of 1974, 63.5 trillion cubic feet of this gas has been added to domestic reserves, leaving an estimated recoverable resource base of 420.5 trillion cubic feet (484−63.5).

TABLE 1.—SUMMARY OF OIL AND GAS INFORMATION

Type	Production 1979	Proved reserves, 1979	Inferred reserves	Resource base	Production, 1990 (estimate)
Conventional oil	2.96 billion bbls/yr.	27.1 billion bbls	17 billion bbls	75 billion bbls	2.2 billion bbls/yr.
	8.1 million bbls/day.				5.8 million bbls/day.
Heavy oil	0.182 billion bbls/yr..	7.5–20.5 billion bbls.		118 billion bbls	.365 billion bbls/yr.
	0.5 million bbls/day.				1 million bbls/day.
Conventional gas	19.9 trillion cu. ft./yr.	194.9 trillion cu. ft	201.6 trillion cu. ft	420.5 trillion cu. ft	17.1 trillion cu. ft./yr.
Unconventional gas:					
Geopressured gas.	None	None		42–1640 trillion cu. ft.	0–1 trillion cu. ft./yr.
Devonian shale gas.	0.1 trillion cu. ft./yr.	2.6–3.4 trillion cu. ft.		200–900 trillion cu. ft.	0.1–0.6 trillion cu. ft./yr.
Tight gas sands	1 trillion cu. ft./yr.	10 trillion cu. ft		240–300 trillion cu. ft.	2–8 trillion cu. ft./yr.
Coal seam gas	None	.08 trillion cu. ft		300 trillion cu. ft	.04–.05 trillion cu. ft./yr.

C. Current Contribution to U.S. Energy Supplies

In 1979, 19.9 trillion cubic feet of conventional natural gas was produced, reversing five consecutive years of production decline. Peak domestic gas production was 22.6 trillion cubic feet in 1973 and since that time production had dropped each year, to a low of 19.3 trillion cubic feet in 1978.

The United States also receives gas from Mexico and Canada. The Mexican gas began flowing on January 15, 1980. The rate is 300 million cubic feet per day (300 billion Btu per day) at a cost of $3.625 per million Btu. Canadian gas, on the other hand, has been flowing to the United States for a number of years, with some long-term contracts in force running to 1995. In December of last year, the National Energy Board of Canada released an additional 3.75 trillion cubic feet of gas for sale to the United States. Although significantly less than the original request for about 9 trillion cubic feet made last summer, the amount is almost twice the volume of the Board's earlier estimate of surplus available for export. The additional gas represents a 40 percent increase over the 9.4 trillion cubic feet remaining to be shipped to the United States under previously issued export licenses.[5]

Some of the new exports began on January 1, 1980, and all existing contracts expire by the end of 1987. Border prices are $3.40 per thousand cubic feet.[6]

[3] Ibid.
[4] Ibid.
[5] Kennedy, Tom. "Industry Welcomes New Canadian Gas Export Levels." The Oil Daily, Dec. 10, 1979.
[6] Ibid.

D. State-of-the-Art

As in the case of oil exploration and development, rotary rigs are capable of drilling to depths of 30,000 feet. In the offshore environment wells can be drilled and completed in water up to 3,000 feet deep and exploratory holes can be drilled in water up to 6,000 feet in depth. This technology can be extended if the discovery patterns and geology indicate hydrocarbon prospects at greater depths which may be economically exploited. Geophysical surveys can be carried out with a high degree of accuracy, but even the "bright spot" seismic technique, a good indicator of the presence of subsurface gas, does not provide an absolute measure of commercial hydrocarbons. A hole still must be drilled to find natural gas or oil. Also, gas pipelines are common as the technology is available to transport large quantities of gas over long distances.

E. Current Research and Development

The drilling and geophysical research and development needed for the discovery and production of hydrocarbons is carried on for the most part by the petroleum industry. The industry is concerned with drill bit design, technology to monitor hole condition during drilling, turbodrill design, and improved geophysical equipment. Offshore drilling R. & D. includes research on various kinds of drilling platforms, usually to increase depth capability and to function in polar waters. The Department of Energy has a $2.37 million R. & D. program to improve drilling and off shore technology systems. This effort also includes research on seafloor instrumentation.[7]

II. PROSPECTS OR REQUIREMENTS FOR FURTHER DEVELOPMENT

To further develop the domestic conventional gas resource, additional exploration and wildcat drilling is necessary. In foreign oil producing states there is often a gas development problem. There may be a surplus of natural gas resulting from the discovery of gas fields in conjunction with oil discoveries, and from associated gas in producing oil fields. In foreign areas which do not export hydrocarbons, the discovery of gas would be beneficial and, like in the United States, the problem is one of exploration and resource base.

In 1977, 10,112 wildcat wells were drilled in the United States. Of these 1,477 became gas producers. For 1977, expenditures for hydrocarbon explorations were as follows: geological and geophysical work, $800 million; land acquisition, $2,800 million; drilling and equipping wells, $3,100 million; and other expenses, $800 million. The average cost per well drilled was $307,000.

The Natural Gas Policy Act of 1978 regulates all aspects of the producer's gas business. Under the Act, price ceilings are set for certain categories of gas to encourage the exploration for and development of additional gas reserves. Maximum price ceilings for existing interstate and intrastate gas contracts were also provided by the Act. There is now a Federally controlled ceiling price for

[7] Department of Energy. Fiscal year 1981 Congressional Budget Report. Fossil Energy Research and Development Energy Production, Demonstration, and Distribution. Vol. 6, January 1980, p. 136-137.

almost all natural gas sales. For newly discovered gas, these prices are independent of whether the gas is sold to interstate or intrastate markets. Higher ceilings have been set to encourage wildcat drilling, while lower ceilings are used to encourage development drilling of proven reserves.[8] Special price incentives have been added to encourage the continued production of low-volume wells and the drilling of high-risk wells. All ceiling prices are the highest amounts to be permitted for the qualifying wells, but are not intended to replace contract arrangements between producers and pipeline purchasers which may provide for lower prices.[9]

During 1968, exploration wells drilled near Prudhoe Bay discovered the largest hydrocarbon accumulation yet found in North America. The field contains an estimated 9.7 billion barrels of liquid hydrocarbons and 26 trillion cubic feet of natural gas. In order to utilize the gas in this giant field, a pipeline would be necessary. The Alaska natural gas pipeline, if completed would become one of the most costly projects in history. Due to the scale of the project, the physical environment in which the line must be built, and legal and environmental constraints, the project has not been started. If the pipeline is completed, the gas known to be in the Prudhoe Bay Structure and other gas discovered in the area could be made available to the lower 48 States. Further, once the Alaska gas pipeline is operating, it would probably be possible to complete the Dempster Highway Lateral Pipeline to recently discovered new gas supplies in the Mackenzie Delta, the Beaufort Sea, and the Arctic Islands of Canada.

III. Potential Obstacles to R. & D. or Technology Implementation

Natural gas has been produced from the ground for over a hundred years. The gas industry is mature and its methods of operation well defined. Domestically, the greatest obstacle to further development is limited access to public lands, rather than inadequate technology. In the United States less than 3 percent of the total continental shelf has been leased for hydrocarbon exploration, compared to between 35 and 50 percent for the rest of the non-Communist world. Also, large areas in Alaska cannot be explored for hydrocarbons because of restrictions on land use. The production of nonassociated gas has less environmental impact than the production of oil. However, there is always a remote chance of a blowout or fire. The production of associated gas (along with oil) includes the potential problems associated with fluid removal, such as subsidence.

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[8] Holland, Charles J. Jr. "Drilling for Gas: It's Complicated Now." World Oil, March 1979, p. 55.

[9] Ibid., p. 56.

IV. Potential Contribution to Future U.S. Energy Supplies

A. *Contribution by 1990*

1. MAINTAINING CURRENT PRODUCTION

Most energy studies completed in the middle 1970's, a time of domestic natural gas shortages, projected a decrease in conventional domestic natural gas production by 1990.[10] To maintain current production of 19.9 trillion cubic feet per year to the year 1990 would require the following: 199 trillion cubic feet of gas would have to be produced during the next decade, and the proved reserves in 1990 would have to be 159.2 trillion cubic feet to maintain a declining annual reserves/production ratio to 8/1. On that basis, a total of 358.2 trillion cubic feet (199 + 159.2) of conventional natural gas would have to be available. Proved natural gas reserves are 194.9 trillion cubic feet. Thus, 163.3 trillion cubic feet (358.2 − 194.9) would have to be added to proved gas reserves during the period. This averages to 16.3 trillion cubic feet per year.

The average reserve additions for the decade of 1970's (including the giant Prudhoe Bay Field) were 12.7 trillion cubic feet per year. If Prudhoe Bay is not included (and such giant fields are very rare), the yearly average was only 10.1 trillion cubic feet. With drilling at a high level, 1977 and 1978 were good years for additions to gas reserves with 11.9 and 10.6 trillion cubic feet, respectively, added. This can be contrasted with only 7.6 trillion cubic feet added to gas reserves in 1976. In 1979, a major drilling effort in response to higher prices, increased reserve additions to 14.3 trillion cubic feet. Thus, it can be seen that the addition of an average of 16.3 trillion cubic feet of gas per year for the next decade would require an immense drilling effort.

It has been estimated that, to maintain current levels of oil and gas production to 1990, oil and gas capital requirements would rise from the current $20 billion to $142 billion in 1990, in current dollars. This is estimated to then be 21 percent of the Nation's total business investments for that year, compared to 9 percent last year. The oil and gas industry is unlikely to capture such a high proportion of total business investment.[11]

2. MAINTAINING CONSTANT ADDITIONS

It is unlikely, given the domestic geological and Federal leasing situation, that 163.3 trillion cubic feet of gas can be added to proved reserves in the coming decade. If the conventional natural gas additions to proved reserves of the past decade including Prudhoe Bay reserves (an average of 12.7 trillion cubic feet of gas per year) and a decline in reserves/production ration to 8/1, are used to project production to 1990, only 17.1 trillion cubic feet of gas per year would be produced at the end of the next decade. Yearly domestic production would be down 2.8 trillion cubic feet, or about 14 percent. Domestic reserves would be down to 137.2 trillion cubic

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[10] Riva, Joseph P. "Present and Future Domestic Supply of Natural Gas. U.S. Energy Demand and Supply 1976–85." Subcommittee on Energy and Power, Committee on Interstate and Foreign Commerce, U.S. Government Printing Office, March 1978, p. 47.

[11] "An Energy Viewpoint From Bankers Trust." Hon. John W. Wydler, Congressional Record. Nov. 8, 1979, p. E5519.

feet from the current 194.9 trillion cubic feet. However, since the reserve additions average of 12.7 trillion cubic feet per year was only surpassed twice in the 1970s, predictions of reduced conventional gas production by 1990 cannot be considered unrealistically pessimistic.

3. AVERTING SHORTAGES

Other current studies have assessed the problems of averting shortages of natural gas. One study indicates that domestic drilling for natural gas must double in the next six years to prevent severe supply shortages. Doubling of drilling activity by 1985 translates into a growth rate of about 12 percent per year in the number of successful gas wells drilled.[12] If such an increase is to be achieved and maintained, it is almost certain that drilling at greater depths and in frontier areas will have to be successful and this will be much more expensive.

B. Contribution by 2000 or Beyond

To attempt to project domestic conventional gas production beyond 1990, it is necessary to estimate the rate of production during the 1980's and the ultimate size of the resource base. With inferred reserves at 201.6 trillion cubic feet and undiscovered recoverable conventional gas resources estimated between 322 and 655 trillion cubic feet, the conventional gas resource base appears to be large enough to sustain significant domestic gas production into the 1990's. The frontier areas will, however, become more and more important as onshore, lower 48 State prospects are exhausted. Also, the exploratory drilling will be deeper. This very deep drilling (below 15,000 feet) will search for gas rather than oil, as the high rock temperatures break oil down into gas at these depths. The cost of drilling in frontier areas and of very deep wells is much greater than the cost of normal onshore drilling. Lead times in frontier areas required to bring gas fields on stream will be at least five to ten years, so some of the gas that will be made available in the 1990's will have to be discovered in the early 1980's.

Conventional gas production will likely decline in the 1980's and this decline will probably continue into the 1990's. The only chance to reverse this trend is to discover many giant gas fields. This is a very slim chance, but if these fields exist domestically they will either be found deeper under known hydrocarbon areas, or in the frontier. In either case they will be expensive to exploit and much time will be needed. The increase in gas production in 1979 was partly the result of a reduction of the reserves/production ratio to below 9/1 in the lower 48 states. It is not likely that this ratio can be reduced much lower, thus new discoveries will be important to increased production rather than producing old fields at faster rates.

Two areas have recently shown promise to significant gas discovery. One area is the Appalachian basin, a long target of oil and gas exploration. However, past drilling has focused mostly on the shallower formations. The basin remains an attractive and highly prospective area to look for hydrocarbons, especially deep gas. Expen-

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[12] "Study Says Drilling For Gas in United States Must Double." Oil and Gas Journal, Oct. 29, 1979, p. 76.

sive and deep exploratory drilling programs in the basin in the past few years have been frustrating to many, but fruitful to a few. There is continued interest in the area, especially since a recent U.S. Geological Survey report indicated that seismic work has shown that the sedimentary rocks in the Appalchian overthrust belt may extend more the 100 miles farther east than originally thought. That would more than double the present area for oil and gas exploration.[13]

A second and potentially more significant region of recent gas exploration is the Overthrust Belt, currently the Nation's best new onshore gas prospect. The area of present exploration lies in Wyoming and Utah, but the belt may extend farther than this, both in a north and south direction. Following five years of intensive exploration, the belt has yielded 12 commercial gas fields. Present production is still rather modest, awaiting new gas plants and pipeline capacity, but reserves appear large by U.S. standards, with the potential to be of real significance if discoveries are made in the older rocks in deeper and broader fold type traps. Thus far 11 different formations have been established as commercially productive, and exploration continues.[14]

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[13] McCaslin, John C. "New Finds Heat Appalachian Basin Interest." The Oil and Gas Journal, Feb. 11, 1980, p. 149.

[14] Anschutz, Philip F. "The Overthrust Belt: Will It Double U.S. Gas Reserves?" World Oil, January 1980, p. 111-116.

OIL *

I. Survey of the Current Situation

A. Description of the Technology

The search for oil begins with the use of general geological knowledge to locate geographic areas that are likely to contain oil reservoirs. When such an area has been found, both geological and geophysical studies are made. Surface and subsurface geology are used to determine the structure and stratigraphy of the area and also may help to locate specific drilling sites. Geophysical surveys consist of reflection and refraction seismology, gravity measurements, and magnetic mapping. These techniques are used to measure the geophysical parameters of the prospect area as an aid in locating geologic structures and, thus, drilling prospects.

As drilling is required to be certain of the existence of an oil reservoir, the basic tool in the discovery of oil is the rotary rig. These rigs have gone through a period of evolution and the largest are now capable of drilling holes in excess of 30,000 feet.[1] Currently, over 3,000 rigs are actively drilling in the United States.[2]

Drilling methods offshore are similar to those onshore, although a platform is needed to support the rotary rig and its associated equipment. As is the case on land, the hole is made by rotating a drill bit on the end of a string of drill pipe. Rock cuttings are removed from the hole by the drilling mud which is circulated through the drill bit. Marine risers have been developed to conduct the drill string to the sea floor, permitting some lateral and vertical movements during drilling operations. There are four basic types of offshore exploratory drilling platforms now in use; barges, drill ships, jack-ups, and semisubmersibles. If commercial accumulations of oil are discovered offshore, production may be accomplished from fixed platforms, gravity platforms, or subsea completion systems.

Very few of the oil wells completed flow of their own accord; about 90 percent require some means of artificial lifting. This can be accomplished by any of the number of pumping systems, the choice of which depends upon the depth of the well, the nature of the reservoir, the gas/oil ratio, the viscosity of the oil, and, of course, the costs involved.

The amount of in-place oil that will flow or can be pumped from a reservoir varies from 5 to 80 percent depending on the pressure in the reservoir, the viscosity of the oil, and the permeability of the reservoir rock. This initial production is known as primary recov-

*Prepared by Joseph P. Riva, Jr., specialist in earth sciences.

[1] "Five Regional Drilling Records Set in 1978." World Oil, Feb. 15, 1979, pp. 93–94.

[2] "Hughes Rig Count." The Oil and Gas Journal, Apr. 28, 1980, p. 157.

ery and averages only about 20 percent of the total in-place oil.[3] Secondary recovery methods can be used to increase the percentage of oil recovery from a given reservoir. These methods either attempt to increase the permeability of the reservoir rock by acidizing or fracturing, or to restore original reservoir pressure by the injection of water or natural gas.[4] Secondary recovery methods can improve recovery to between 30 to 60 percent of the total in-place oil.

The enhanced recovery processes devised to recover that part of the oil remaining after the use of secondary methods are termed tertiary techniques. These techniques usually attempt to reduce oil viscosity and capillarity by the introduction of heat or other injected substances such as carbon dioxide, polymers, solvents, surfactants, and micellar fluids in various combinations depending upon reservoir conditions.[5] Tertiary techniques can further increase recovery, from 40 to as much as 80 percent of the total in-place oil in the reservoir, depending upon the process used and the reservoir conditions.

B. Known Resources and Reserves

The United States' proved crude oil reserves dropped by an estimated 1.7 billion barrels in 1978, despite the highest level of drilling activity in 20 years. Industry estimates of proved reserves (identified quantities of oil considered, on the basis of engineering and geological knowledge, to be recoverable under current economic conditions) were 27.8 billion barrels as of December 31, 1978, down from the 29.5 billion barrels estimated a year earlier.[6] More than 1.3 billion barrels were added to reserves in 1978, but 3.03 billion barrels were produced, leading to the drop in estimated reserves. In 1979, proved reserves again dropped, but this drop was only about 700 million barrels, to an estimated 27.1 billion barrels.[7] Since 1970, total additions to domestic conventional oil reserves have averaged only about 1.9 billion barrels per year, excluding the addition of Prudhoe Bay reserves in 1970. With drilling continuing to increase, the success rate for exploration has declined. However, reserve additions last year were up about 0.86 billion barrels over the year before.

The reliability of estimates of the proved productive reserves volumes of new discoveries or of partially developed reservoirs varies according to the amount of geological information available at the time the estimate is being made. Such necessary factors as the areal extent of the reservoir, the average thickness of the producing horizons, the thickness of the oil column within the reservoir, and the continuity of the reservoir characteristics cannot be determined accurately without sufficient subsurface information. The ultimate size of newly discovered reservoirs (in old or new fields) is seldom determined in the year of discovery. Thus, first year estimates of proved reserves in new reservoirs are often small-

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[3] Riva, Joseph P., Jr. "Secondary and Tertiary Recovery of Oil." Report Prepared for the Subcommittee on Energy of the House Committee on Science and Astronautics, U.S. Government Printing Office, Washington, D.C., October 1974, p. 55.

[4] Ibid.

[5] Ibid.

[6] "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1978," American Petroleum Institute, American Gas Association, Canadian Petroleum Association, v. 33, June 1979, pp. 22–23.

[7] "Decline in Reserves of U.S. Oil Slowing," Washington Star, May 8, 1980.

er than the total that will eventually be assigned, resulting in upward revisions in subsequent years on the basis of additional information provided by new drilling and production.[8]

Inferred reserves are those reserves, in addition to proved reserves, which should eventually be added to proved reserves through extensions, revisions, and new producing zones in known fields. Inferred reserves are estimated by extrapolating the rate of growth of discovered petroleum volumes for each region of the United States using correction factors based upon the time lapse since the initial year of discovery. The wide variability in the data used and the fact that proved reserves are also estimates cause a significant degree of uncertainty in the calculations of inferred reserves.[9] Inferred reserves in the United States were calculated by the U.S. Geological Survey at 23.1 billion barrels of oil at the end of 1974. Inferred reserve figures are now estimated at between 13 and 21 billion barrels.

Undiscovered petroleum resources are even more difficult to estimate. The total amount of petroleum recoverable from a sedimentary basin is determined by the volume originally generated from the deposited organic matter and by the geologic history of the basin. The amount of oil theoretically formed may be estimated from the volume and quality of the source rocks, and comparisons to known oil producing areas; and then all the available lithologic, tectonic, hydrodynamic, and physical data can be employed to arrive at a projection of the quantities of oil which may be expected to be trapped and eventually recovered. However, any such volumetric estimates necessarily have a low reliability since a relatively small and unexpected change in the thickness of a source bed or in the continuity of a reservoir horizon can affect a resource estimate in a partly explored region by a very large factor. The U.S. Geological Survey's most recent estimate of undiscovered domestic oil resources is given as a range of 50 to 127 billion barrels.[10] The low value of the range is the quantity associated with a 95 percent probability that there is at least that amount and the high value is the quantity of oil associated with a 5 percent probability of occurrence. The statistical mean for undiscovered recoverable oil reserves is 82 billion barrels.[11] These estimates were as of December 31, 1974. Since that time an additional 7.4 billion barrels of oil have been discovered.

If the statistical mean is used, then about 74.6 billion barrels of oil (82 −7.4) may remain undiscovered in the United States. However, the 1974 assessment did not include offshore areas beneath more than 200 meters of water or much new drilling data which has since become available. Therefore, a new Geological Survey assessment is under way which will include the deeper portions of the continental shelves and revisions in areas where more complete subsurface information is now available.

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[8] Riva, Joseph P., Jr. "Present and Future Domestic Supply of Oil and Natural Gas Liquids. U.S. Energy Demand and Supply 1976–85." Report Prepared for the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, U.S. Government Printing Office, March 1978, p. 36.

[9] Ibid.

[10] Miller, Betty M., et al. "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States." Geological Survey Circular 725, National Center, Reston, Va., 1975, p. 28–29.

[11] Ibid.

C. Current Contribution to U.S. Energy Supplies

For the United States, liquid hydrocarbons are the primary source of energy, currently satisfying about one-half of total energy demand. In 1978, 3.03 billion barrels of domestic crude oil (about 8.3 million barrels per day) were produced from conventional reservoirs. To satisfy domestic demand, however, it was also necessary to import 2.275 billion barrels of foreign crude oil, at an average rate of 6.2 million barrels per day. Crude oil imports, however, were down 0.139 billion barrels from a peak of 2.414 billion barrels in 1977, while domestic production was up about 6 percent. Both the reduction of imports and the increase in domestic production were the result of a large increase in production from the giant Prudhoe Bay field, located on the north slope of Alaska. In 1979, domestic oil production slipped to 2.96 billion barrels (about 8.1 million barrels per day).

D. State-of-the Art

Rotary rigs are capable of drilling to depths in excess of 30,000 feet. Offshore rigs can drill and complete wells in water depths of up to 3,000 feet and exploratory drilling can be conducted in water depths of up to 6,000 feet. The technology can be extended if the discovery prospects appear to warrant the expense. Seismic, magnetic, and gravity surveys can be carried out with a high degree of accuracy, but even the new "bright spot" seismic technique is not a direct measurement of subsurface hydrocarbons. A hole must still be drilled to confirm the presence of oil.

In the United States enhanced (tertiary) recovery field tests result in the production of in excess of 375,000 barrels per day of oil. There are over 350 currently active and planned enhanced recovery projects. While most of these projects involve field tests of the thermal recovery of heavy oil, there are an increasing number of tests of gas and chemical floods. However, because of the complex nature of these field tests, a number of years are necessary for evaluations to be completed.[12]

E. Current Research and Development

Drilling and geophysical research and development are carried on mostly by the petroleum industry, whose concerns include drilling bit design, turbodrills, and improved geophysical sensors.

Offshore drilling R. & D. includes work on drillships and semisubmersibles with increased depth capacities and the ability to work in polar areas, and on drilling platforms for deep water, such as gravity and tension leg platforms. Enhanced oil recovery research is done in both the private and the Federal sectors. The objective of the Department of Energy's $19.4 million program is to assess the potential of enhanced oil recovery and to develop the technology needed to make enhanced recovery technically and economically feasible.[13]

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[12] Noran, Dave. "Growth Marks Enhanced Oil Recovery." The Oil and Gas Journal, Mar. 27, 1978, p. 114.

[13] Department of Energy. Fiscal year 1981 Congressional Budget Request. Fossil Energy Research and Development Energy Production, Demonstration, and Distribution. Vol. 6, January 1980, p. 127.

II. Prospects or Requirements for Further Development

For further domestic and foreign development of the conventional oil resource, additional drilling and production are necessary. In 1976 an estimated $14.5 billion was spent on domestic exploration and production combined.[14] Exploration and production expenditures have, of course, increased since because of inflation and increased oil activity.

In 1977 10,112 domestic exploratory holes were drilled. Of these, 1,209 became oil producers; 1,477 became gas producers, 7,276 were dry holes; and 151 were drilled for stratigraphic information. Thus, 27 percent of the exploratory drilling was successful. For 1977 domestic expenditures were as follows: geological and geophysical work, $0.8 billion; land acquisition, $2.8 billion; drilling and equipping wells, $3.1 billion; and other expenses, $0.8 billion, for a total of $7.5 billion. The average cost per well drilled was $307,000 and the total average exploration cost per barrel of oil found was $2.82. Half of the money was spent by 20 major integrated oil companies and the other half by about 5,000 independents of which about 300 are publicly owned companies. In addition to the funds provided by the major oil companies and many of the independents, the use of capital raised by public subscription drilling funds is an important source of money for some independents. The funds raised by about 50 companies in this manner were estimated to be about $539 million in 1977.[15]

On a broader scale, it has been estimated that it would cost $179 billion to drill the number of new field wildcats believed necessary to maintain 1978 discovery levels through 1990.[16] It has also been projected that in excess of $1 trillion will be necessary to meet the world's oil needs for the 10 year period that began in 1977.[17]

In Federal R. & D. for the current fiscal year, the request from DOE for petroleum R. & D. includes $2.37 million for drilling and offshore technology (to deploy, monitor, and evaluate seafloor instrumentation) and $19.4 million for enhanced oil recovery. The enhanced oil recovery request represents a decrease of $2.0 million from the previous year. Also, a recent DOE Economic Regulatory Administration rule permits producers to recoup 75 percent of some of the costs of using specific enhanced oil recovery techniques. This is accomplished by increasing prices on some of their crude oil to world market levels. No more than $20 million can be recouped from any one property.[18] This ruling is expected to provide additional capital for enhanced recovery projects.

III. Potential Obstacles to R. & D. or Technology Implementation

The exploration for and production of conventional oil is an activity that has been underway throughout the world for over a century. The petroleum industry is mature and its methods of

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[14] Capital Investments of the World Petroleum Industry and Financial Analysis of a Group of Petroleum Companies. The Chase Manhattan Bank, Basic Petroleum Data Book, American Petroleum Institute, October 1978, sec. V, table 9.

[15] Arthur D. Little, Inc. Unpublished report.

[16] Haun: "New Finds Require Drilling, Spending Hike." Oil and Gas Journal, Oct. 15, 1979, p. 94.

[17] Andrews, Bruce. "$1 Trillion to Meet Oil Needs." The Oil Daily, Jan. 6, 1977.

[18] "ERA Allows Some Recovery of Tertiary Project Costs." The Oil Daily, Aug. 28, 1979.

operation well-developed. In the United States the greatest obstacle to implementation of the existing technology is limited access to some Federal and State lands. Large land areas, especially in Alaska, are precluded from exploration and less than 3 percent of the total U.S. continental shelf has been leased for oil and gas exploration. This compares to about 35 percent in other non-Communist countries. In Africa and Oceania well over half of the continental shelf areas are under lease and in Asia the leased shelf area approaches 40 percent.[19]

Oil recovery sometimes causes environmental problems. The production of underground fluids occasionally is responsible for the settlement of the land surface. Injection of fluids, as in some secondary or tertiary recovery processes, has been known in very rare instances to have triggered small earth tremors. If the well is not adequately cased, injected fluids also may enter aquifers and pollute drinking water. The stream generators used to produce injection stream for thermally enhanced oil production can cause substantial air pollution problems.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Most energy studies completed in the middle 1970s projected domestic oil production gains by 1985 and certainly by 1990. In a survey of ten such studies, five carried the projections to 1990. The average of the 1990 estimates for domestic oil production was 4.6 billion barrels.[20] To actually achieve such production in 1990 the following conditions would have to be met: (*a*) about 38.6 billion barrels of oil would have to be produced between 1980 and 1990, gradually increasing from the present 2.96 billion barrels per year to the 4.6 billion barrels projected; and (*b*) the proved reserved in 1990 would have to be 41.4 billion barrels to sustain a reserves/production equal to the present 9/1 in 1990 (physical constraints generally limit annual withdrawal to an amount equal to about 1/9 of proved reserves).

Thus, total oil needed by 1990 to attain a production of 4.6 billion barrels per year is 80 billion barrels (38.6 billion + 41.4 billion). Proved reserves in 1979 were 27.1 billion barrels and inferred reserves have been estimated at about 17 billion barrels. Additional oil may come from enhanced oil recovery. Estimates show that by 1990, 3 million barrels of oil per day may be derived from known fields by the use of enhanced oil recovery methods, at a price of $25 per barrel.[21] If this optimistic estimate is extrapolated back to 1980 using available tables,[22] enhanced oil recovery would very optimistically account for an additional 7.2 billion barrels between 1980 and 1990. Thus, the oil available in 1990 would be 27.1 billion barrels (proved reserves) + 17 billion barrels (inferred reserves) + 7.2 billion (enhanced recovery form existing fields) = 51.3 billion

[19] "Search for Oil Will Focus Offshore." International Petroleum Encyclopedia, The Petroleum Publishing Company, Tulsa, Okla., 1976, pp. 282–283.
[20] Riva, Joseph P. "Present and Future Domestic Supply of Oil and Natural Gas Liquids. U.S. Energy Demand and Supply 1976–85," Subcommittee on Energy and Power, House Committee on Interstate and Foreign Commerce, U.S. Government Printing Office, March 1978, p. 41.
[21] National Petroleum Council estimate.
[22] Ibid.

barrels. Since a total of 80 billion barrels would be needed to sustain a production of 4.6 billion barrels in 1990, 28.7 billion barrels would have to be discovered during this period.

To find 28.7 billion barrels of oil between 1980 and 1990, the average discovery rate would have to be 2.9 billion barrels per year, but the average rate of proved reserve additions would have to be 5.3 billion barrels per year (new discoveries plus inferred reserves and enhanced recovery additions). This can be compared to the average per year additions to proved reserves for the past 10 years (including Prudhoe Bay, the largest field, by a factor of two, ever discovered in the United States), which were only 2.8 billion barrels per year. If the Prudhoe Bay field is not included, the average rate of additions to proved reserves for the same period is reduced to 1.9 billion barrels per year. Last year additions were only 2.21 billion barrels, with domestic drilling at a 20-year high.

For further comparison, proved reserve additions in 1975 were 1.3 billion barrels; in 1976, 1.1 billion barrels; in 1977, 1.4 billion barrels; and in 1978, 1.3 billion barrels. Thus, it would appear that the addition of 5.3 billion barrels of oil to proved reserves per year each year for the next 10 years would be virtually impossible to achieve. It would require the discovery of the equivalent to two more Prudhoe Bay fields (18.8 billion barrels) in addition to finding 1.9 billion barrels of oil per year (the average, not including Prudhoe Bay, of the past 10 years), plus the conversion of all present inferred reserves to proved reserves and the enhanced recovery of a very optimistic 7.2 billion barrels of oil, total, from known fields. If fact, many recent projections have estimated either level or declining domestic oil production into the next decade.[23]

For domestic oil production even to remain level at 2.96 billion barrels per year, however, additions to proved reserves would have to average 2.96 billion barrels per year for the period. If the average proved reserve additions for the past 10 years (excluding Prudhoe Bay) of 1.9 billion barrels per year are used, along with a reserves/production ratio of 9/1, production at the end of 1990 would be only 2.22 billion barrels per year (6.1 million barrels per day), a decline of about 25 percent from current levels. Enhanced oil recovery may increase these additions, but enhanced recovery projects are long term prospects and a very large number would have to be initiated early in the decade to realize significant production by 1990.

To add to proved reserves enough oil just to average 1.9 billion barrels per year for the 10-year period to 1990 would require an expanded drilling program and the discovery of a number of major fields. To better this amount, and have a chance to maintaining a level domestic production would require that giant fields be discovered and that widespread success with enhanced recovery projects be realized. Giant fields of the size needed could probably only be found in such frontier areas as the continental margins and Alaska, if at all. Drilling success in these areas thus far has not been encouraging, and it should not be assumed that such giant fields will be discovered.

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[23] For example, "The World Oil Market in the Years Ahead." Central Intelligence Agency, ER 79-10327U, August 1979, 80 p.

It is much more likely that sufficient oil will not be found or produced by enhanced recovery methods to prevent domestic production from declining throughout the decade. This does not mean that exploration drilling should be abandoned as unprofitable, as any oil found will be of obvious benefit. It does mean that, while there is still hope of significant discoveries, domestic oil can not be assumed to be available at current quantities in the future.

B. Contribution by 2000 or Beyond

The projection of domestic conventional oil production beyond 1990 depends upon the ultimate size of the resource base and the rate at which domestic exploitation will take place in the decade of the 1980s. If some 75 billion barrels of conventional oil currently remain to be discovered, some of this amount will still remain to be found in the years beyond 1990. Enhanced recovery will also play a role. To be significant, however, such projects will have to be on a large scale and will take many years to complete. However, as the domestic resource is depleted in explored area, oil will become harder and harder to find. The discoveries will tend to be smaller and deeper. An important prospect area, however, will be the large areas offshore and in Alaska, now precluded from exploration. If finally leased, these regions might contain major, or even giant, fields. It is such large fields that could make a significant contribution to production levels, as (if not too remote) they can be exploited quickly, thus making amounts of oil available with relatively few wells. Another potential domestic prospect not now economic is in the deeper waters offshore.

Domestic oil production will almost certainly continue to decline beyond the 1990's, with the only possibility of reversing this decline being the very slim chance of many giant field discoveries in very remote and difficult environments. Enhanced recovery techniques will probably also be widely employed, but they can not be expected to reverse the downward trend.

COAL-BASED TECHNOLOGIES

COAL LIQUEFACTION *

I. Survey of the Current Situation

A. Description of the Technology

Coal liquefaction is the process of converting pulverized coal to synthetic liquid fuels. The conversion of coal into liquid fuel products is based on increasing the proportion of hydrogen to carbon found in coal: by either indirect hydrogenation (sometimes called synthesis processing) or direct hydrogenation (sometimes called degradation processing).[1] In the indirect route, coal is degraded or broken down by a gasification reaction into simple units that are subsequently reacted together to form refined fuel products. In the direct hydrogenation route, liquid products are obtained by a less drastic treatment in which some of the original coal structures are preserved.[2] First generation (or commercially proven) processes are generally based on the indirect liquefaction route; second generation (or advanced) processes are generally based on direct liquefaction. Fuels processed from coal are considered to be synthetic fuels.

B. Known Resources and Reserves

Coal resources are estimated at more than 1.7 trillion tons of which about 437 billion tons are considered to be reserves with about 283 billion tons being recoverable reserves.[3] Thus, the potential availability of coal is not a constraint to the emerging coal liquefaction industry.

C. Current Contribution to U.S. Energy Supplies

Only experimental quantities of coal liquids are now produced in the United States. Thus, the current contribution of coal liquefaction to U.S. energy supplies is negligible.

D. State-of-the-Art

The Engineering Societies Commission on Energy, Inc. (ESCOE), has reviewed the status of various first and second generation liquefaction processes, many of which have received Department of Energy (DOE) support, and has appraised the time required to have a demonstration plant designed, built, and ready for start-up of

*Prepared by Paul F. Rothberg, specialist in physical sciences.

[1] Hydrogenation is the chemical combination of hydrogen and another substance.

[2] National Coal Board Report. "Liquid Fuels from Coal." (England) August 1978. p. 9.

[3] See chapter on conventional coal.

operations. Indicators of process status and the projected year in which a demonstration plant could be ready to start operation are shown in table 2.[4]

TABLE 2.—STATUS OF SELECTED ACTIVE COAL LIQUEFACTION PROCESSES

Process	Status (key to numbers are below)	Demonstration start year
Clean solid: SRC–I—Solvent refined coal	7	1983
Liquefaction:		
Fischer-Tropsch	9	1983
Methanol	9	1982
SRC–II—Solvent refined coal	7	1983
Cresap (LC-fining)	6	1985
M-gasoline	6	1985
EDS—Exxon's donor solvent	4	1985
H-Coal	4	1984
ZnCl	1	1988
Co-Steam	1	1988
Synthoil	1	1995

PROCESS STATUS
(roughly linear with time)

0 Proposed Process
1 Successful Process Demonstration Unit Operation
2 Economic Studies Done
3 Competitive Cost Established
4 Pilot Plant Designed
5 Pilot Plant Operating
6 Successful Series of Pilot Runs
7 Demo Plant Design Begun
8 Demo Plant Operating
9 Proven Demonstration Plant

Source: Rogers, Kenneth A. "Overview of Coal Conversion." ESCOE ECHO, February 1979: 2.

Once a process has been proven at the demonstration stage, it is ready for commercialization. As can be inferred from table 2, an adequate technology base exists to establish a commercial liquefaction industry using the Fischer-Tropsch and methanol synthesis processes.

E. Current Research and Development

The DOE's appropriation for its coal liquefaction program for fiscal year 1979 was about $217.9 million, its fiscal year 1980 appropriation is about $250.3 million, and its fiscal year 1981 budget request is $523.9 million. The DOE's strategy is to support several liquefaction processes concurrently from the laboratory scale, through process development units, to the pilot plant stage, with only the most promising processes advanced, primarily on a cost-shared basis, at this last stage. The DOE's program is designed to reduce technical uncertainties and to obtain information on economic and environmental aspects of processes that have been developed and evaluated through industry and government efforts.[5]

In addition to participation in the DOE program, the private sector is spending millions of dollars on the research and development of proprietary liquefaction processes. The total sum spent on these activities is unavailable.

International efforts to advance this technology could also aid the emerging U.S. coal liquefaction industry. Over the last twenty-

[4] Rogers, Kenneth A. "Overview of Coal Conversion." ESCOE ECHO. February 1979: 2.
[5] For additional information see: U.S. Department of Energy. Fossil Energy Program Summary Document. Available from NTIS, March 1979, 469 p.

five years, the South African Coal, Oil & Gas Corporation (SASOL) has operated a liquefaction plant based on the Fischer-Tropsch process. SASOL and an American engineering company have agreed to license in the United States the technical advances developed at the SASOL plant.[6] A U.S. plant using SASOL's licensed process would have to be designed to meet U.S. market requirements, e.g., the high grade or premium lead-free gasoline product output could be maximized to meet U.S. market demands. SASOL is now completing work on a second plant (SASOL II) which is expected to turn about 40,000 tons of coal per day into about 58,000 barrels of liquid products.[7]

II. Prospects or Requirements for Further Development

A. *Research and Development*

Research and development can make long-term contributions to the state-of-technology of coal liquefaction. Listed below are selected technical areas that could be addressed by further research and development.

1. ENVIRONMENTAL EMISSIONS

The potential hazards due to human exposure to, and emissions of, chemicals from liquefaction plants could be further studied. DOE has recognized the need for intermediate- and long-term environmental, health, and safety monitoring of different processes at the various scales of development and commercialization, emphasizing data on equipment reliability, the fate of solid waste compounds, and the sources and extent of released or fugitive emissions. Such studies may disclose a critical environmental problem for synfuels generally, or for a specific process, that could require new control regulations or, in the extreme, could rule against the use of a specific process. In addition, improvements in the state-of-the-art environmental control guidelines and standards could be established to foster improved control technology and engineering practices.[8]

2. MATERIALS PROBLEMS

The high temperatures and pressure conditions under which liquefaction reactions are run result in equipment and materials problems. Reducing damage to pumps and valves caused by these severe reaction conditions presents a major technological challenge. Continued work to improve the reliability and stability of special materials used in coal liquefaction plants could improve liquefaction technology.[9]

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[6] "Coal: Closing Cost Gap with Oil." Chemical Week. Sept. 12, 1979: 45.
[7] "SASOL II Makes Its First Liquid Products from Coal." The Energy Daily. Mar. 13, 1980: 1.
[8] U.S. Department of Energy. Synthetic Fuels and the Environment: An Environmental and Regulatory Impacts Analysis. (Review Draft) Jan. 7, 1980. pp. 1-3.
[9] Based on discussions with researchers at the Morgantown Energy Technology Center, Morgantown, W. Va., 1979.

3. CHEMICAL CATALYSIS AND PROCESS DYNAMICS

Improved understanding of the catalytic reactions and process dynamics of coal liquefaction could lead to new processes with improved efficiencies.[10]

4. PRODUCT TESTING

There is little data on the handling, storage, and combustion characteristics of coal liquids burned in utility steam boilers or in gas turbine combustors. Additional information in these areas is needed by potential users of synthetic coal-derived liquids.

B. Demonstration

To advance second generation liquefaction technology, DOE and industry are constructing two large pilot plants and plan to construct two demonstration facilities. The pilot plants will cost over $200 million each and the demonstration facilities may cost at least $2.0-$2.2 billion each.[11]

At least two to five years of enormous scale-up and additional testing will be required to reduce the technological uncertainties and to establish the commercial readiness of the advanced systems.[12] Successful operation of these projects is designed to convince industry that advanced liquefaction processes are ready to be scaled up to the pre-commercial or commercial level.

C. Commercialization

The innovation of coal liquefaction technology will be a slow and gradual process. Any company seeking to commercialize this technology would typically proceed through a series of steps, as indicated below:

Step No. 1. Project feasibility study—one to two years required;

Step No. 2. Obtain necessary funding for huge capital expenditure required and obtain regulatory permits and approvals necessary to start construction—roughly two to five years required; and

Step No. 3. Construct a commercial size plant—about five years required assuming a concerted effort for early completion and no interruptions because of legal actions.[13]

Although steps No. 1 and No. 2 could be combined, there is still a substantial lead time involved in commercializing a plant.

Commercialization of liquefaction technology is currently impeded by an array of technical, institutional, regulatory, economic, and environmental constraints (see sec. III. below). Both industry and Government could possibly learn how to reduce these constraints by constructing and operating large scale or commercial facilities.

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[10] For additional information on research and development needs and opportunities see: Gorbaty, Martin L. et. al. "Coal Science: Basic Research Opportunities." Science, Nov. 30, 1979: 1029-1034.

[11] The two pilot projects will test the H-Coal process and the Exxon Donor Solvent process. The two demonstration facilities will test the SRC I and SRC II processes.

[12] For additional information see project timetables in U.S. Department of Energy. Fossil Energy Program Summary Document. op. cit., pp. 77-105.

[13] ESCOE. "Comparison of Coal Liquefaction Processes." April 1978. Washington, D.C., p. 7.

Operation of these facilities should provide needed information on air emissions and aqueous discharges and on the effectiveness of environmental control systems designed to protect air, water, and land quality. By commercializing one or more projects, industry could acquire information on the actual costs and competitiveness of this technology and could gain experience in project financing; Government could learn how to improve its regulation of this industry. If these projects prove successful, industry might accelerate its commercialization efforts. If unsuccessful, both government and industry should learn where further work would be beneficial.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

Federal and industry technologists judge that first generation processes, such as the Fischer-Tropsch or methanol synthesis processes, are technically ready for the marketplace. Because of the experience acquired at the SASOL projects, scale-up of first generation processes in the United States is not considered a major technical problem.[14]

A major technical constraint associated with advanced liquefaction processes is the scale-up problem that was previously discussed (see sec. II. B, above). Successful operation of large pilot plants and demonstration facilities would substantially reduce the technical risks of scale-up.[15]

B. Economic

Industry has not yet started to construct the first U.S. commercial coal liquefaction plant. Given past conditions and Federal policies affecting synfuels commercialization, the private sector was reluctant to commit the capital required to commercialize such a project for a variety of reasons. Possibly the most important of these were the economic constraints associated with the production of oil from coal, including:

(*a*) Future production costs which may increase substantially;

(*b*) Uncertainty regarding the future competitive price of oil in international markets;

(*c*) The huge amount of capital required for each project; and

(*d*) The risks of major project delays, which could also substantially increase project costs.[16]

However, with the recent passage of legislation creating the United States Synthetic Fuels Corporation and DOE's Alternative Fuels Production Program (see section III. E.), the Federal policies affecting synfuels commercialization have significantly changed. The Federal Government now has the authority to offer substantial incentives to reduce the economic constraints facing synfuels commercialization. However, no U.S. company to date has allocated the

[14] U.S. Department of Energy. Commercialization Strategy Report for Coal Liquefaction. (Draft) 1978. p. 18.

[15] Ibid., p. 5.

[16] See Cameron Engineer's Report in: U.S. Congress. Senate. Committee on the Budget. Subcommittee on Synthetic Fuels. Synthetic Fuels, 96th Cong., 1st sess. (Washington, Government Printing Office, 1979).

huge capital—roughly $3.6 million or more—that would be required to construct a commercial facility.[17] The private sector has repeatedly stated that it is unlikely to proceed with the first commercial plant until the Federal Government provides substantial financial incentives. For example, one consulting group stated:

> [P]rivate industry will not be willing or able to shoulder all of the financial burdens of a synfuels program. Financial institutions are similarly unwilling to participate in synfuels projects because of the technical, environmental and regulatory uncertainties which surround first-of-a-kind ventures. In short, without an aggressive incentives program to lessen the financial burdens on project sponsors, there will be no development of a synfuels industry in the foreseeable future.[18]

The case to the contrary is as follows: when industry can produce and sell synthetic oil at a clear profit in the market that exists, investment funds will be forthcoming through normal market channels. The Federal Government, in providing major economic incentives to promote commercialization, risks subsidizing costly projects that may not prove competitive and could lose an undetermined part of the Federal investment.

C. *Environmental*

Construction and operation of a commercial plant could result in many adverse environmental impacts. Such a project would require the mining and processing of huge amounts of coal and the construction of roads, plant facilities, waste disposal areas, and utility and pipeline corridors. Potential environmental problems include: adverse health and safety aspects of coal mining; increased use of scarce water resources (especially in the West); and increased pollution of land, air, and water resources.

During coal liquefaction, many substances, some of them carcinogenic or potentially so, could be produced as contaminants. Among these are beryllium, nickel, carbonyl, phenols, benzene, chromium, cadmium, polycyclic aromatic hydrocarbons, lead, and zinc chloride. Other potential pollutants which can cause severe damage to human health are mercury, nitric acid, nitrous oxide, nitrogen dioxide, selenium, sulfur dioxide, carbon monoxide, arsenic, and barium cyanide.[19]

Although the number of potential problem pollutants is large and contains some particularly dangerous materials, it seems possible that emission control technology exists or can be developed to reduce potential pollutants to tolerable levels. This is certainly the case for the more commonly encountered pollutants occurring in fairly large quantities. The case for trace element contamination is less clear.[20]

Many public interest groups have expressed concern over the possible environmental problems that could be caused by large scale production of coal liquids. As evidence in numerous congressional hearings, executive agency meetings, and the press, some of these groups have urged a cautious approach towards commercialization. The collective influence of these groups on both public and

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[17] Cost estimate from: Fluor Engineers. "A Fluor Perspective on Synthetic Liquids, 1979."
[18] Cameron Engineers, Inc., op. cit., p. 185.
[19] U.S. Congress. Senate. Committee on Energy and Natural Resources. Synthetic Fuels from Coal: Status and Outlook of Coal Gasification and Liquefaction. 96th Congress, 1st session, [Washington, Government Printing Office, 1979], pp. 4-5.
[20] Ibid.

private decisionmakers is one of several factors that has constrained the growth of the coal liquefaction industry. For example, some decisionmakers have cited conerns over the expected environmental impacts of synfuels production as one of the reasons for opposing legislation designed to expedite synfuels commercialization.[21]

Another constraint faced by this industry is the complex array of Federal, State, and local laws and standards that regulate commercial operations. For example, it has been stated that "the existing body of laws and regulations . . . is extremely burdensome and has the effect of drawing out the time schedule required to bring a project on line." [22] More than twenty Federal laws can affect synfuels plants. Because of associated application procedures and required administrative actions, it will be extremely difficult for industry to proceed rapidly with its production plans.

Similar regulations affect the coal liquefaction and the coal gasification industries. As has happened to the gasification industry, the emerging liquefaction may encounter long delays in obtaining regulatory permits. (See Chapter on High Btu Coal Gasification). It is uncertain whether commercial plants, incorporating appropriate pollution control technology and industrial hygiene practices, will be able to meet applicable standards.[23]

D. Social

The social impacts from commercialization will primarily depend upon (a) the size, number, and location of plants, (b) the existing infrastructure of affected communities, and (c) the financial resources available to support enlarged or new communities. New schools, roads, hospitals, and recreation facilities would be needed by synfuels construction and plant workers and their families. With careful advance planning and substantial financial resources, many of the social problems associated with commercialization could be reduced.[24]

E. Political

The coal liquefaction industry faces many political constraints, including complicated Federal and State regulatory policies and procedures, the failure of public agencies to specify all environmental standards, and changing Federal policies affecting commercialization.

Primarily since the oil embargo of 1973–74, Congress has been considering major Federal economic and regulatory incentives to promote the commercialization of synfuels, including coal liquids. Congress has only recently passed laws offering substantial incentives. Uncertainties regarding the future of "Federal Synfuels Policy" have created some uncertainties for industry. For example, if a company wanted to participate in a commercial project, it had

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[21] See congressional hearings and floor debate/discussions re: President Nixon's Project Independence Plans or President's Synfuels Commercialization Program.
[22] Cameron Engineers, Inc., op. cit., p. 184.
[23] The Energy Mobilization Board could possibly expedite the regulatory process affecting the commercialization of synfuels plants.
[24] For additional information see: U.S. Congress. Senate Subcommittee on Regional and Community Development Committee on Environment and Public Works. Inland Energy Development Impact Assistance Act of 1977. 95th Congress, 1st session. (Washington, Government Printing Office, 1977.)

to make major financial decisions without knowing (*a*) the role that the Federal Government would have in coal liquids production, (*b*) whether major Federal economic incentives would be provided to encourage commercialization, and (*c*) all the environmental standards and regulatory procedures that would influence commercial operations. Consequently, industry did not know the "ground rules" that would influence the feasibility of commercial liquefaction plants.

However, the 96th Congress devoted much attention to legislation that will affect synfuels commercialization and that could help clarify the Federal role in the area. Two new initiatives that received considerable attention were proposals to create the United States Synthetic Fuels Corporation (SFC) and the Energy Mobilization Board (EMB). The SFC is directed to provide major economic incentives for commercialization, and the EMB might have expedited regulatory decisions affecting commercialization. Thus these agencies might have significantly influenced the feasibility of commercial coal liquefaction plants by reducing some of the uncertainties previously discussed. However, the EMB proposal was not enacted into law.

F. Legal

Some of the Federal environmental standards that will regulate a coal liquids industry have not yet been promulgated. These regulations may be challenged in court and other legal problems, such as environmental lawsuits, could delay commercialization.[25]

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

As previously indicated, construction of the first commercial plant has not yet begun; neither has any company allocated the huge capital required to complete construction. Some companies, however, have announced either their interest or their plans to invest in commercial plants designed to produce liquid fuels or chemicals from coal.

The current and anticipated level of industrial activity indicates than an average daily commercial production level of 100,000 to 200,000 barrels of oil equivalent could be reached by 1990. However, to reach this level the Federal Government would have to provide substantial Federal economic incentives and would have to ensure that regulatory policies and practices allow commercialization to proceed.[26] Much of this production could be obtained from about three to five plants using proven, first generation technology. If work proceeds satisfactorily on large scale pilot plants or demonstration facilities between now and 1982–86 and decisions are made to scale up to commercial plants, advanced or second generation plants could also contribute to this production level.

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[25] U.S. Congress. Senate. Committee on Energy and Natural Resources. op. cit., p. 110.
[26] Similar range of estimates has been prepared by Cameron Engineers, Inc., see: Cameron Engineers, Inc. op. cit., p. 155.

B. Contribution by 2000 or Beyond

Projections on the contribution of coal liquids to U.S. energy supply beyond 1990 are highly speculative. If coal liquefaction proves to be environmentally acceptable and economically feasible, and if the Federal Government promotes production activities, it seems possible that a production level of roughly 0.5–1.2 million barrels per day by 2000 could be reached.[27] The upper range might be reached with major Federal support; whereas, the lower range might be reached if the environmental, regulatory, and economic factors discussed previously continue to constrain production.

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[27] Estimates of the upper range can be found in: Committee on Nuclear and Alternative Energy Systems, U.S. Energy supply Prospects to 2010. (Washington, National Academy of Sciences, 1979), p. 86.

HIGH-BTU COAL GASIFICATION *

I. Survey of the Current Situation

A. Description of the Technology

Coal gasification is a chemical technology in which pulverized coal is converted into combustible gas which may be of low-, medium-, or high-Btu (heat) content per cubic foot.[1] In its simplest form, the gasification of coal requires, first, the heating of the coal, and second, the reaction of its carbon and hydrogen content with steam to produce carbon monoxide, carbon dioxide, hydrogen, and methane. In general, gasification reactions are based on thermal decomposition of coal (i.e., the application of heat to break down the structure), followed by gasification or combustion of the resulting char. The reaction vessel may be pressurized or operated at atmospheric conditions.

This chapter deals only with high-Btu processes, which are designed to maximize the production of methane, the major component of natural gas.

B. Summary of Known Resources and Reserves

See chapter on Coal Liquefaction, section I.B.

C. Current Contribution to U.S. Energy Supplies

Industry and Federal researchers are currently producing only experimental quantities of high-Btu coal gas in laboratory and in pilot plant studies. Thus, the current contribution of this fuel to U.S. energy supplies is negligible.

D. State-of-the-Art

The status of various first and second generation gasification processes, most of which have received support from the Department of Energy (DOE), have been appraised as to the time required to have a demonstration plant designed, built, and ready for initial operations. Indicators of process status and the projected year in which a demonstration plant could be ready to start operation are shown in table 3.[2]

As table 3 indicates, the Lurgi/methanation process, which is considered a first generation process, has proven successful at the demonstration phase. Federal and industry technologists judge this process ready for use in a commercial facility. All of the other

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*Prepared by Paul F. Rothberg, specialist in physical sciences.

[1] Btu—British thermal unit—is a quantity of heat, the amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit. Gases processed from coal can be characterized by their heat content measured in Btus per cubic foot of gas.

[2] Rogers, Kenneth A. Overview of Coal Conversion. Engineering Societies Commission on Energy, Inc. ESCOE ECHO. Feb. 26, 1979: 2.

processes listed in table 3 are advanced processes and are less well developed, and thus pose greater technical risks for investors.[3]

TABLE 3.—STATUS OF SELECTED ACTIVE COAL CONVERSION PROJECTS

Process	Process status (key to numbers are below)	Year of demonstration plant
Gasification, pipeline quality gas:		
Lurgi/methanation	9	1983
Conco (slagging Lurgi)	7	1983
Cogas	7	1983
Hygas	6	1986
Bigas	5	
Gasification, industrial sector:		
Texaco gasifier	5	1984
Exxon catalytic gasification	3	1987
Rockgas	2	1988
Combined cycle: To provide electricity:		
Westinghouse	4	1986
Combustion engineering	4	1986

PROCESS STATUS
(roughly linear with time)

0 Proposed Process
1 Successful Process Demonstration Unit Operation
2 Economic Studies Done
3 Competitive Cost Established
4 Pilot Plant Designed
5 Pilot Plant Operating
6 Successful Series of Pilot Runs
7 Demo Plant Design Begun
8 Demo Plant Operating
9 Proven Demonstration Plant

Source: Rogers, Kenneth A. "Overview of Coal Conversion". Engineering Societies Commission on Energy, Inc. ESCOE ECHO. Feb. 26, 1979: 2.

E. Current Research and Development

The DOE's coal gasification program is intended to advance second and third generation systems for processing a variety of gaseous products from coal. This program is divided into two major efforts: surface and *in situ* (underground) processing. The DOE's appropriation for its surface program for fiscal year 1979 was about \$112.4 million and the fiscal year 1980 appropriation was about \$115.9 million. The DOE's appropriation for its *in situ* program for fiscal year 1979 was \$15 million and the fiscal year 1980 appropriation was \$10 million.[4] Approximately \$67 million of the fiscal year 1979 funds and \$85 million of the fiscal year 1980 funds will be used to advance high-Btu gas technology.[5]

Working jointly with industry, DOE and its predecessors have advanced several new high-Btu gasification processes from the research laboratory or bench scale level to the pilot plant stage. The next step in the Department's program is to test several processes at the demonstration scale (see II.B below).

[3] For additional information see: German, Michael I. "The Role of High-Btu Coal Gasification Technology", presented at the Coal Conference and Expo V, Louisville, Ky., Oct. 25, 1979: 4. (Inquiries regarding this article should be addressed to the American Gas Association, Arlington, Va.)

[4] These funding levels include monies used to support all types of gasification processes. Research and development on low- and medium-Btu gasification could yield information useful in advancing high-Btu gasification processes. All estimates are from DOE.

[5] Alm, Alvin. Letter to J. Bennett Johnston in Johnston, J. Bennett. "The Costs of Energy," Congressional Record. May 23, 1979: S6566–6568.

Besides working jointly with the Federal Government, the private sector is supporting research and development on proprietary processes, but the total amount spent on these activities is unavailable. Industry has spent several hundred million dollars to plan commercial high-Btu coal gasification projects.[6]

Research activities conducted abroad could also aid the developing U.S. gasification industry. For example, the Environmental Protection Agency, through a joint program with the Yugoslav Government, is monitoring emissions and effluents on several coal gasifiers that use a reactor system known as a "fixed-bed" system which is currently operating in Prestina, Yugoslavia.[7] Information obtained from this program could be useful in planning health, safety, and environmental controls for U.S. plants.

II. Prospects or Requirements for Further Development

A. *Research and Development*

Federal officials who worked on the Market Oriented Program Planning Study identified several major technical barriers inhibiting the commercialization of high-Btu coal gasification. These barriers, apply to the majority of processes within this generic technology, both first and second generation processes, and define areas where research and development could be focused, such as:

(*a*) Introduction of coal feed or input solids and removal of solid residues from highly-pressurized gasification reactor vessels;

(*b*) Sulfur poisioning (or degradation) of nickel-based methanation catalysts and other problems associated with the methanation process;

(*c*) Development of high-volume, high-pressure oxygen compressors;

(*d*) Materials corrosion/erosion in gasification system components, promoted by process conditions;

(*e*) Development of appropriate treatment and disposal technologies to minimize leaching and subsequent contamination of ground and surface waters by gasifier solid residues and water treatment sludges; and

(*f*) Process designs that would accommodate a range of coal feedstock characteristics (e.g., ash content, caking properties, grindability) in order to increase the amount of usable resource.[8]

Continued research and development on coal gasification processes could result in important advances in the current state of technology. However, in terms of starting a U.S. coal gasification industry, demonstration and commercial projects are now more important than is additional research and development. (See II.C below)

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[6] Unpublished testimony of George Lawrence, American Gas Association, before Subcommittee Energy Development and Applications of the House Committee on Science and Technology, Mar. 4, 1979, p. 6.

[7] Dickenson, Ronald L. and Dale R. Simbeck. "SNG Plant-Byproducts Need Attention". Oil and Gas Journal. Mar. 12, 1979: 67.

[8] U.S. Department of Energy. Market Oriented Program Planning Study (MOPPS), v. 5. Part III. December 1977. p. III-5.

B. *Demonstration*

Industry and DOE are working jointly on the initial phases of three demonstration projects designed to advance second generation processes. If these demonstration plants prove successful, a large scale industry using these advanced processes could be developed during the 1990s.[9]

C. *Commercialization*

Commercialization of coal gasification technology is impeded by an array of technical, institutional, regulatory, economic, and environmental constraints and uncertainties.[10] By constructing and operating commercial projects, industry and Government could learn to reduce or handle the impediments to commercialization. If a project were commercialized, industry could obtain information on the real costs and the competitiveness of this energy option, on air emissions and aqueous discharges, and on the effectiveness and costs of environmental control systems. Government could gain needed experience in regulating this industry. Successful commercialization would establish the economic feasibility of this technology and might convince industry to accelerate its commercialization efforts. An unsuccessful effort should indicate if and where further work would be beneficial.

Information on the financial requirements for commercialization is provided in III. B. below.

III. Potential Obstacles To R. & D. or Technology Implementation

A. *Technical*

Although the technical components of first generation systems are proven and available commercially, some technical risks are still associated with construction and operation of large scale plants. The integration of all components into a working, commercial project, i.e., one producing 75 to 275 million cubic feet per day, has not yet been accomplished. However, industry and government technologists generally agree that integration of the various components and scale-up of first generation processes in a commercial facility is a manageable technical problem.[11]

Second generation (or advanced) processes pose much greater technical problems than first generation processes because the advanced processes have thus far been tested only in pilot plants. Before they can be commercialized, second generation processes need to be scaled up in demonstration plants. According to DOE projections, at least five years would be required to complete construction and initial operation of these demonstration facilities.[12] At the demonstration scale, technologists seek to optimize process

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[9] For additional information see: U.S. Congress. Senate. Synthetic Fuels from Coal: Status and Outlook of Coal Gasification and Liquefaction. 96th Cong., 1st sess., June 1979.

[10] Ibid.

[11] For example see: U.S. Department of Energy. Commercialization Task Force for High-Btu Gasification (Draft). 1978, p. 1.

[12] U.S. Department of Energy. Fossil Energy Program Summary Document. March 1979, p. 134.

dynamics at high coal input levels, thus possibly improving the overall economics and efficiency of advanced processes.

B. Economic[13]

Three major economic constraints associated with the commercialization of high-Btu coal gasification technology include:

(*a*) the expected price of the product relative to conventional gas,

(*b*) the difficulty of obtaining economic regulatory decisions from the Federal Government that are acceptable to project participants and to institutions that are willing to finance proposed projects, and

(*c*) the huge front-end capital required to construct a commercial plant.

1. EXPECTED PRICE OF THE GAS

Without Federal incentives, the short-term economic outlook for high-Btu coal gas plants appears to be quite unfavorable. Economic analyses performed both by the Federal Government and by industry indicate that the expected selling price of high-Btu coal gas will exceed that of conventional gas at least during the initial period of plant operations. For example, one industry group has estimated that the 1983 price of coal gas would be $6.25 to $8.25 per million Btu.[14]

However, economic feasibility should not be judged solely on the basis of comparing the costs per million Btu of coal gas versus the costs per million Btu of conventional gas. Consideration should also be given to the cost that the end users will have to pay for other ways to heat their homes. Several studies have indicated that for residential users it would be much less expensive on a cost per million Btu basis to heat a home using synthetic gas from coal than using conventional electrical heat generated from coal.[15] In addition, high Btu coal gas seems relatively competitive with imported oil, which is currently selling for roughly $6 to $7 per million Btu.

2. ECONOMIC REGULATORY DECISIONS

Because of the anticipated high price of coal gas, industry seeks Federal economic regulatory decisions that allow the gas to be sold on a "rolled-in" basis to consumers. This financial mechanism allows industry to "average in" the price of high-Btu gas with that of conventional gas to all consumers receiving gas from a specific company. Industry has had much difficulty in obtaining such regulatory decisions from the Federal Government.[16]

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[13] The Synthetic Fuels Corporation (discussed later in this chapter), is authorized to provide a range of incentives to reduce the economic constraints discussed in this section.

[14] Estimate made in: "America's First Coal Gas Plant Is Ready To Go" The Energy Daily. Sept. 15, 1978. Conventional interstate gas now sells for roughly $1.50–$1.75 per million Btu. Even if the price of natural gas doubled over the next 3 years, it would still be less expensive than SNG.

[15] For example see: American Gas Association. A Comparison of Coal Use for Gasification Versus Electrification. Energy Analysis. Apr. 26, 1977.

[16] For example: The American Natural Resources Co., a participant in the Great Plains Project, has been attempting for over 7 years to obtain the financing commitments and regulatory approvals necessary to construct a commercial plant.

3. HUGE FRONT-END COSTS

Approximately $1.5 billion would be required to construct a commercial plant producing 125 million cubic feet of gas per day.[17] The capital requirements to construct a plant of this size are large relative to the net worth of many of the companies seeking to commercialize this technology. Because of the large financial commitments (both debt and equity requirements) associated with a commercial facility, the financial community reportedly remains "unwilling to provide necessary funds without assurance of repayment for the first several full-scale plants." [18]

C. Environmental

Construction and operation of a commercial plant producing 125 million cubic feet per day could result in many adverse environmental impacts. Such a project would require the mining of huge amounts of coal (i.e., 25 million pounds per day) and the construction of roads, plant facilities, waste disposal areas, and utility and pipeline corridors. Potential environmental problems include: the adverse health and safety aspects of coal mining, the use of scarce water resources (especially in the West), and the release of polluting materials (such as toxic solids) to the environment. However, technology, such as waste water treatment, is available to reduce some of those pollutants.

Many public interest groups have expressed concern over the possible environmental problems that could be caused by large scale production of high-Btu coal gas. Before congressional hearings, in the press, and before Federal environmental and economic regulatory bodies, some groups have urged a cautious approach towards commercialization. The collective pressure of these groups on both public and private decisionmaking is one of many factors that has affected the commercialization of the coal gasification industry.

Another constraint faced by the emerging high-Btu coal gas industry is the complex array of Federal, State, and local laws and standards that will regulate commercial operations. This regulatory system, including the permitting process, environmental standards, and certification proceedings, will make it extremely difficult for industry to proceed rapidly with any plans developed. Companies have already encountered long delays in obtaining permits and final certificates required to operate commercial facilities.[19] It is still uncertain whether commercial plants, incorporating appropriate pollution control technology and industrial hygiene practices, will be able to meet all future Federal and State standards.[20]

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[17] Based on data from the American Natural Resources Co., the uncertainty associated with this estimate should be emphasized. Large construction projects, such as a coal gasification plant, have typically experienced large cost overruns.

[18] American Gas Association. Fact Book: Synthetic Pipeline Gas from Coal. Arlington, Va., 1979, p. tab C., 1.

[19] For example, consider the American Natural Resources project (previously cited) which has been delayed because of problems encountered in obtaining a "non-appealable," final regulatory decision from the Federal Energy Regulatory Commission (FERC).

[20] The Energy Mobilization Board, if enacted into law, could possibly expedite the regulatory process now affecting the commercialization of high-Btu coal gasification plants.

D. Social

See: Coal Liquefaction, III. D.[21]

E. Political

See: Coal Liquefaction, III. E.[22]

F. Legal

See Coal Liquefaction, III. F.[23]

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Construction of the first high-Btu coal gasification plant in the United States has not yet started. Before construction can commence, a project must receive an economic regulatory decision from the FERC. Although one project has recently received such a ruling, several groups (opposed to FERC's ruling) have successfully appealed the decision before the Federal courts. The start of construction of this project, which might prove to be the Nation's first commercial plant, was threatened with a delay of up to one year while the courts reached a decision on this appeal.[24] However, the DOE decided to provide the project with a $1.5 billion loan guarantee, which is conditional upon receiving certain Federal approvals.

At least six months to one year will probably be required to "shakedown" the plant, i.e., to reduce or remove technical problems. A production rate of 137 million cubic feet of high-Btu coal gas per day, which is roughly equivalent to 22,000 barrels of oil per day, could be reached after the shakedown period. If initial operations were successful, this plant could be enlarged to a production level of roughly 250 million cubic feet per day by 1990.[25]

Several other companies have announced plans to commercialize high-Btu coal gasification plants. Participants of these projects are beginning to: (1) apply for Federal and State certificates to construct and operate commercial plants, (2) apply for DOE funds to conduct project feasibility studies or to enter into cooperative arrangements with DOE, or (3) prepare to apply for financial incentives to be offered by the United States Synthetic Fuels Corporation (SFC).

If the first project were commercialized by 1984 or 1985 and if the Federal Government provides substantial economic or regulatory incentives for several additional projects, it is possible that average commercial production levels by 1990 may reach .5 to 1 billion cubic feet of high-Btu coal gas per day, which is equivalent to 88,000 to 176,000 barrels of oil per day. This projection takes into account the current and anticipated plans of industry (as discussed above), the long lead times (4-5 years) involved in constructing a

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[21] The social, political, and legal constraints associated with high-Btu coal gasification are similar to those associated with coal liquefaction.
[22] Ibid.
[23] Ibid.
[24] Based in part on discussions with officials of the American Gas Association and the American Natural Resources Co., 1980.
[25] Ibid.

full scale gasification plant, and the numerous environmental and regulatory uncertainties facing this industry. The higher level of production could be reached if four projects, each producing about 250 million cubic feet per day were commercialized.[26] [27]

B. Contribution by 1990 or Beyond

Given the current state of industrial development, estimates of high-Btu gas production from coal beyond 1990 are highly speculative. The level of production beyond 1990 may depend upon an array of factors, including: (*a*) the availability and price of natural gas, (*b*) the success of the first few commercial projects using first generation processes and demonstration projects testing advanced processes; and (*c*) Federal policies affecting the commercialization of this technology.

Some forecasters predict that high-Btu coal gasification could provide 1.8 trillion cubic feet per year (or roughly 900,000 barrels of oil equivalent per day) by 1995, and 3.3 trillion cubic feet per year (or roughly 1.65 million barrels of oil equivalent per day) by 2000.[28] Although these projections may prove correct, these estimates now appear to be overly optimistic in view of the financial resources of the natural gas industry, the amount of dollars available through Federal incentives that will be available for this technology, the long lead times and major uncertainties associated with commercialization, and the current state of industrial development. To reach the level of production projected for 2000, industry would have to build 37 coal gas plants over the next twenty years. Even officials of the gas industry realize the difficulty of accomplishing this enormous task. For example, one official stated: "between now and the end of the century, about 30 commercial scale facilities could be constructed and operating." [29] [30]

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[26] Similar estimates have been developed by Cameron Engineers of Denver, Colorado. For example, see: U.S. Congress. Senate. Committee on the Budget. Subcommittee on Synthetic Fuels. Synthetic Fuels. 96th Congress, 1st session, 1979: 155.

[27] Additional gas production could be obtained from DOE-industry synfuels demonstration projects or from coal liquids projects producing gas as a byproduct; however, the amount of this gas cannot yet be quantified.

[28] Amercian Gas Association, Fact Book: Synthetic Pipeline Gas from Coal, op. cit., p. 5.

[29] Statement of William McCormick, Jr. as quoted in "U.S. Synfuel Plans May Speed Coal Gasification." Oil & Gas Journal, Oct. 1, 1979: 29.

[30] Each plant would have to produce 250 million cubic feet per day.

MAGNETOHYDRODYNAMIC POWER GENERATION *

I. Survey of the Current Situation

A. Description of the Technology

Magnetohydrodynamic power generation, or magnetohydrodynamics (MHD), is a method of converting heat into electrical power. In principle, any high temperature heat source could be applied to an MHD generator. However, the U.S. MHD program is aimed at utilizing MHD in conjunction with coal-fired combusters.

Electricity is generated when an electrical conductor is moved through a magnetic field. In a conventional generator, this is accomplished by having expanding steam cause a metallic conductor attached to a turbine shaft to rotate. In a coal-fired MHD generator the conductor is composed of the hot gaseous products of coal combustion, which have been made electrically conducting by the addition of a material (potassium or cesium) called a seed. These gases are exhausted through a chamber, roughly the size of a bus, called the channel, which is surrounded by a large magnet. The flow of electricity which is thereby generated in the gases is collected by electrodes located in the walls of the channel.

The MHD process of direct generation of electricity, without first boiling water to run a steam generator, may allow as much as 50 percent more electricity to be generated from a ton of coal than conventional methods.

When the combustion gases leave the MHD generator they still contain a large amount of heat which must be recovered for economic operation. Some of this heat can be used to boil water to run a conventional steam turbine generator. As currently envisaged, a commercial MHD plant will consist of an MHD "topping cycle" and a steam turbine "bottoming cycle." About half of the electrical output will be generated in each.

For economic operation, it is also necessary to recover the seed material before the exhaust gases are vented to the atmosphere. Sulfur readily combines chemically with the seed material, and hence the seed recovery operation is also an efficient means of removing the sulfur pollutants normally released by coal combustion.

The process described above is called open-cycle MHD power generation. A closed-cycle process has also been studied, in which the fluid which operates within the generator is in a closed loop. Heat from the coal combustion must be transferred to the fluid via a heat exchanger. This method is not as promising as open-cycle MHD for baseload power generation, and it presents some difficult technical problems which may not have solutions. However, some resources continue to be devoted to closed-cycle generation because

*Prepared by Robert Civiak, analyst in energy technology.

it may eventually prove advantageous for use with heat sources other than coal and for the supply of peaking power. Unless otherwise noted the discussion below refers to open-cycle MHD.

B. Known Resources and Reserves

Although the MHD process is applicable to other types of fuel, research in the United States centers on coal. The United States has extensive coal resources, which are discussed elsewhere (see Conventional Coal, I.B). The MHD process could generate as much as 50 percent more electricity per ton of coal consumed than conventional generation methods. This would considerably extend the availability of coal resources.

Approximately one per cent of the seed material used in the MHD process will not be recovered. Hence, supplies of this material must be considered. The best seed material from a performance standpoint is cesium. However, world cesium resources are not sufficient to support a large number of MHD plants. A more likely seed material is potassium. With projected seed recovery rates, if ten percent of the current U.S. electricity generation was by MHD, approximately 60 thousand tons of potassium salts would be consumed annually. This is only 2.5 percent of current U.S. production and an insignificant fraction of world reserves of potassium salts, which are principally located in Canada.

C. Current Contribution to U.S. Energy Supplies

MHD is not currently contributing to U.S. energy supplies.

D. State-of-the-Art

No fundamental scientific barriers to MHD power generation are known to exist: However, the technology is far from commercial development in the United States. Much engineering development is yet necessary. Individual components, (e.g., combustors, channels, magnets, and heat exchangers) have been built and tested at generally much smaller scales than would be necessary for a commercial plant and under simulated rather than actual power generation conditions. No complete integration of the components necessary for a commercial MHD plant has taken place on any scale.

Nevertheless, great progress has been made in the design of individual components. For example, the operating lifetime of MHD channels has been increased from several minutes to one thousand hours, which is within a factor of two of the minimum lifetime that will be needed in a commercial plant.

While many details need to be worked out, systems design studies have been performed which establish the basic operating requirements of the major components.

Close-cycle MHD research is not as advanced as open-cycle. Technical feasibility has yet to be proven for the closed-cycle process.

E. Current Research and Development

Currently, nearly all of the research on MHD in the United States is performed under contract to the Department of Energy (DOE), which spent $80 million for this purpose in fiscal year 1979 and has requested $71 million for fiscal year 1981. The DOE baseline development plan for commercialization of MHD is to proceed in three overlapping phases. The purpose of the first phase is development and testing of MHD core components at up to 50 megawatts thermal (Mwt).[1] These components will be scaled up in the second phase, which will be a complete pilot-scale plant of 250Mwt, called the Engineering Test Facility (ETF). This facility, which will feed its power production into a utility grid, is mandated by Public Law 93-404 to be built in the State of Montana. Operation of the ETF should lead to a full-scale commercial demonstration plant, generating approximately 1,000Mw of electricity. According to the baseline plan, this plant is scheduled to begin operation in 1997.

The key facility of the first phase of MHD development is the 50Mwt Component Development and Integration Facility (CDIF), located in Butte, Montana, which is scheduled to begin operation in 1980. Another major facility for the integration and testing of components at up to the 20Mwt level is the Coal-Fired-Flow Facility in Tennessee. Test programs have been underway there at less than 20Mwt for several years and have recently been upgraded to the higher power level. At least twenty other primary contractors, including private firms and government laboratories, are involved in MHD development.

Upon submission of the fiscal year 1981 budget request, DOE proposed an accelerated development program for MHD. This new plan calls for doubling the capacity of the CDIF to 100Mwt in 1982 and also doubling the size of the ETF to 500Mwt. According to this plan, the ETF would be the final step required before private industry could move forward with commercial MHD plants in the early 1990s. According to DOE, the new plan, while adding about $120 million to development costs during the 1980's, could ultimately save $1 billion by eliminating the need for a Federally funded commercial demonstration plant. However, a report by the General Accounting Office (GAO)[2] notes that the faster development schedule increases the risk of failure and "it is not clear that utilities will be willing to build commercial MHD systems based on the results of a 500-Mw pilot plant."

Additional alternatives to the baseline plan for the ETF are being considered by DOE. One such plan involves adding an MHD topping cycle onto an existing small fossil power plant. This would not necessarily advance the schedule for development of MHD, but could reduce the cost to the Government. It would also bring utility participation into MHD development at an early stage, which might prove useful in the commercialization phase in the late 1990s. Increased utility participation in MHD development has been endorsed by the GAO.[3]

In addition, consideration is being given by private interests to retrofitting a coal combuster and a 50-75Mw MHD generator to an

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[1] The abbreviation Mwt will be used for megawatts of heat and Mw will refer to megawatts of electricity throughout this chapter.

[2] Magnetohydrodynamics: A Promising Technology for Efficiently Generating Electricity from Coal; Report to the Congress by the Comptroller General of the United States. Washington, U.S. General Accounting Office. February 1980, 50 p. EMD-80-14.

[3] Ibid.

existing 125Mw oil-fired power plant.[4] At the current state of development of MHD, it is not expected that this would be cost competitive with 75Mw of new generating capacity, but other considerations such as economic incentives to switch from oil to coal might make it attractive to the utility.

The United States cooperates with other countries, including Japan, Poland, and the Soviet Union, which have MHD development programs. The most advanced foreign program is that of the Soviet Union. The Soviets plan to develop MHD technology using natural gas and light oils as fuels before tackling the more difficult problem of coal burning. The Soviet 20Mw U-25 facility is the largest MHD facility in the world capable of continuous operation. Construction of a pilot plant of 500Mw is scheduled to begin in the Soviet Union in 1980.

II. Prospects or Requirements for Further Development

A. Research and Development

The technical feasibility of MHD power generation has been demonstrated by experiments performed thus far. The major focus of the Phase I research and development effort is the accumulation of the engineering data and experience needed to design the Engineering Test Facility. The DOE baseline plan estimates that Phase I will cost about $600 million for research and development through 1984. At that time, enough information should have been accumulated to begin the design of the ETF.

The CDIF is the only facility planned to test components at the 50Mw level. Efforts to obtain funding for large scale testing facilities at the site of component manufacturers or at the Coal-Fired-Flow Facility have been unsuccessful.

The letting of simultaneous development contracts for components, with the ultimate selection of the best design, could speed MHD development. Currently three manufacturers are building combustors at the 20Mw level and one will be chosen to build the 50Mw combustor for the CDIF. This parallel development is not being applied to other components.

Estimates of the time that could be saved by building additional test facilities or adopting parallel development efforts are not available.

B. Demonstration

The key to the demonstration phase of MHD development will be the ETF. There is currently some disagreement over what needs to be demonstrated by this facility. The cautious approach, put forth by DOE's MHD Program Office in their Program Plan for Open-Cycle Magnetohydrodynamics, is to demonstrate commercial feasibility by the operation of the ETF. However the draft final report of the DOE MHD Review Board states that, "In attempting to support a commercial feasibility demonstration, choices among technologies and components may be overly deferred and the maintenance of multiple options in some cases may cause competition for scarce financial, manpower and facility testing time and

[4] Roldiva, Inc. of Pittsburgh in cooperation with Southern California Edison Co.

space."[5] The Board concludes that the current schedule, which calls for detailed design of the ETF to begin in 1984 and construction in 1986, could slip as much as two years if the current Program Plan is followed. In addition, this approach would require several years of operation of the ETF before a decision could be made to begin the commercialization phase of MHD development.

A popular position among MHD contractors is that the ETF need only provide additional engineering data and some economic information to lead to the commercialization phase. With this goal, it would be possible to move up the schedule for the ETF by making decisions on EFT design options sooner, while continuing research at lower power levels to optimize the performance of MHD plants.

This approach would require increased funding levels for MHD to begin early design of the ETF. While it could lead to early commercialization of MHD, there is an element of risk in this approach. It could require a large commitment of funds before MHD has proven to be more efficient and less costly than other alternative technologies. It could also result in the premature rejection of MHD, if the economic information provided by the ETF is unfavorable, or requires that another pilot-scale plant be built to incorporate engineering improvements before the commercialization phase can begin.

The current DOE estimate of the cost of the ETF is $400 million and of the entire Phase II development phase is $1 billion. Operation of the ETF is scheduled to begin in 1990.

C. Commercialization

Commercialization of MHD is too far in the future to be able to present the requirements necessary to achieve it with any certainty. The current DOE plan is for a commercial demonstration plant to begin operation in 1997. Significant commercialization of MHD would follow that by at least ten years. If a scaled up 500Mw ETF completed in the early 1990s is the final demonstration plant required, commercialization could begin as early as the year 2000.

Utility companies are currently only marginally involved in MHD development programs. If commercialization efforts are to be successful, utility company input will have to be obtained well before the design of the commercial demonstration plant begins.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

Much progress has been made in MHD during the past five years, and there are no scientific problems which will require a breakthrough in current understanding to solve. However, many complex engineering problems remain.[6]

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[5] U.S. Department of Energy. R. & D. Coordination Council. MHD Review Board. Draft Final Report. June 15, 1979, p. 4.

[6] U.S. Department of Energy. Division of Magnetohydrodynamics. Draft Program Plan for Open Cycle Magnetohydrodynamics. March 1979. 1 volume in various pagings.

1. POWER EXTRACTION AND SCALING PROBLEMS

The physics of MHD indicates that generator efficiency should increase with the size of the generator. This has proven correct thus far. However, the largest generator operated has achieved only a 15 percent conversion of thermal to electrical energy, while efficiencies of at least 20 percent are needed for commercial operation. Unforeseen problems may develop at the higher power extraction levels of larger machines.

2. PLANT DURABILITY AND RELIABILITY

MHD generators operate under extremely corrosive conditions. It is believed that in commercial operation a generator will have to be able to operate for at least 2000 hours. Current generators can be expected to provide about 1000 hours of service. The remainder of the plant must meet much stricter reliability criteria. Present experimental facilities cannot demonstrate the reliability that will be needed for power production in a utility setting.

3. SYSTEM INTEGRATION FOR HIGH EFFICIENCY

Thus far components have largely been developed separately. For economical operation it is necessary that components be integrated in a manner which allows for the retention of as much useful heat energy as possible. Several problems remain in doing this.

One example of an unsolved problem is how to use the heat downstream from the generator to preheat air being fed to the combustor in order to maintain the high combustion temperatures needed. However, first generation MHD plants could eliminate this problem by increasing the percentage of oxygen in the air. Another unsolved problem relating to system integration concerns the retention of the unburned coal residues, called slag, in the combustor. If the slag is retained in the combuster, overall thermal efficiency goes down. However, if it is allowed to travel downstream it complicates generator design and makes seed recovery difficult.

B. Economic

MHD is too far from commercial development for reliable cost projections. However, in 1976, the Energy Conversion Alternatives Study (ECAS) [7] found MHD to have the potential to produce electricity for the lowest cost when compared to fluidized bed coal combustion, combined cycle gas turbines, coal gasification, fuel cells and several other fossil fuel based technologies. However, ECAS also determined that all these other technologies were closer to development than MHD. For this reason the study concluded that MHD had a poorer probability of development than some other new coal technologies. Later studies have supported these findings.[8]

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[7] Energy Conversion Alternatives Study (ECAS) Summary Report, prepared for National Aeronautics and Space Administration, Energy Research and Development Administration, and National Science Foundation. NASA TM-73871

[8] For example, Comparative Study and Evaluation of Advanced Cycle Systems, prepared by General Electric Company for Electric Power Research Institute. Final Report, February 1978, contract AF-664. 3 volumes.

One economic difficulty with MHD is that it requires large plants in order to be economical. In addition, maximum efficiency is obtained only when the plant is operated near full power conditions. Both of these conditions are undesirable from the standpoint of a utility's total load profile. Closed-cycle MHD could be superior to open-cycle MHD in this respect if it should prove technically feasible.

C. Environmental

MHD is generally believed to present fewer environmental problems than other coal-based technologies. Sulfur emissions from an MHD plant could be kept to a very low rate by the demands of seed recovery.

It is believed that nitrogen oxide emissions can be kept well below anticipated standards by controlling the cooling rate of the combustion products.[9] Some penalty in efficiency must be paid to do this, but it is not considered a serious problem.

The expected high efficiency of MHD will reduce the amount of coal consumed, which is an advantage when compared to other coal based technologies. However, the adverse environmental impacts of coal mining and transportation, although reduced, will remain, as will the question of the effects of carbon dioxide in the atmosphere when MHD is compared to non-fossil energy alternatives.

D. Social

N/A.

E. Political

Public Law 93-404 mandates that the ETF be built in the State of Montana. If DOE decides to combine the ETF with an existing power plant or include it as part of a larger new power plant planned by a utility, as it is currently considering, it could be difficult to find a suitable site in Montana.

F. Other

Competing advanced fossil fuel technologies, such as fluidized bed combustion and coal gasification, are more developed than MHD. This may result in greater emphasis on those technologies which offer an earlier payoff. MHD will appear less attractive if large amounts of funds are invested in other technologies, even if ultimately it would prove to be a more economic means of producing electricity.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

As the beginning of engineering design for the intermediate scale ETF is still at least two years away, it is extremely unlikely that even a major development effort could bring a full scale MHD plant into operation by 1990. A pilot scale plant could be in operation by that date, producing about 500 thermal megawatts.

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[9] Matray, Paul and Gordon Huddleston. MHD Emissions and Their Controls. Environmental Science and Technology, vol. 13, p. 1208. 1979.

B. Contribution by 2000 or Beyond

The current DOE MHD development schedule calls for the initial operation of a commercial demonstration plant in 1997. If utilities wait for information from the operation of this plant to order MHD facilities, large scale commercialization appears unlikely to occur until at least ten years later. If commercialization directly follows the operation of an upgraded ETF, it is possible that a few 1,000 Mw plants could be in operation by the year 2000.

The limitations of projecting costs and market shares for undeveloped technologies twenty years into the future are well known. In a recent study it was predicted that beginning in the year 2004 and continuing indefinitely, because of cost advantages, over 85 percent of the new orders for baseload electricity generating capacity would be for power plants consisting of MHD topping cycles and steam turbine bottoming cycles.[10] The other technologies considered in this study included: light water reactors, gas turbine combined cycle systems, and atmospheric and pressurized fluidized bed systems. However, given the current level of uncertainty, it cannot be known with certainty if MHD will account for any part of commercial electricity generations in this period.

[10] Comparative Study and Evaluation of Advanced Cycle Systems, prepared by General Electric Company for Electric Power Research Institute. Final Report, February 1978, contract AF-664, 3 volumes.

OTHER TECHNOLOGIES FOR THE UTILIZATION OF COAL *

I. Survey of the Current Situation

A Description of the Technologies [1]

1. LOW-BTU COAL GASIFICATION

Low-Btu gas is produced by the combustion of coal in the presence of steam and air. After cleanup, the resulting gas is composed principally of nitrogen, carbon monoxide, and hydrogen, with a heating value of less than 200 Btu per cubic foot. To achieve a heating value equivalent to that of natural gas, a volume of low-Btu gas nearly five times that of natural gas is required.[2] The typical mode of operation would be in a single-user plant with an energy output of roughly 0.5–2.0 billion Btu/day.

2. MEDIUM-BTU COAL GASIFICATION

Medium-Btu gas is produced by the combustion of coal in the presence of steam and oxygen. After clean-up, the resulting gas is composed principally of carbon monoxide and hydrogen, and its heating value is in the range of 300 to 600 Btu per cubic foot.[3] The principal mode of operation would be in a single-user plant with energy output of at least 7 to 10 billion Btu/day or in a multiple-user plant with an energy output of at least 30 billion Btu/day.

3. COMBINED CYCLE COAL GASIFICATION

In this system, coal is gasified by the low-Btu process, cleaned, and used as fuel for a high temperature gas combustion turbine which produces power and heat.[4] The low-Btu fuel gas is fed to the gas turbine system to produce electric power, and the hot exhaust gases from the turbine pass through a heat recovery steam generator to produce high pressure steam, which may be used subsequently in a steam turbine or may be used for a variety of purposes in other parts of the plant. A combined cycle plant producing 100 MWe (megawatts electric) of power is currently being planned for California.

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* Prepared by Robert E. Morrison, specialist in marine science, and Paul F. Rothberg, specialist in physical sciences.

[1] The four coal technologies discussed in this chapter were judged to be among the ones most likely to make some contribution to near-term U.S. energy supplies.

[2] U.S. Department of Energy. Commercialization Strategy Report for Low-Btu Gasification. TID–28851 (Draft). 1978, p. 4. Subsequently cited as DOE Low-Btu Gasification report.

[3] U.S. Department of Energy. Commercialization Strategy Report for Medium-Btu Gasification. TID–28850 (Draft). 1978, p. 3. Subsequently cited as DOE Medium-Btu Gasification report.

[4] U.S. Department of Energy. Commercialization Strategy Report for Advanced Electric Generation Technologies. TID–28839 (Draft). 1978, p. 1. Subsequently cited as DOE Advanced Electric Generation Technologies report.

4. ATMOSPHERIC FLUIDIZED BED COMBUSTION

In this process, coal or other fuels are burned in a bed of limestone or other material to remove sulfur. Heat is removed by boiler tubes immersed in and above the combustion chamber. The process is adaptable to a wide variety of applications, including both utility and industrial steam generation.[5] The approximate capacity of coal-fired atmospheric fluidized bed systems in the United States ranges from .3 MWe to 30 MWe.

B. Known Resources and Reserves

For a summary of known coal resources and reserves, see the chapter of this report dealing with conventional coal utilization.

C. Current Contributions to U.S. Energy Supplies

1. LOW-BTU COAL GASIFICATION

In the 1920s and 1930s, prior to the establishment of the domestic natural gas industry, thousands of low-Btu coal gasifiers were in operation. With the introduction of the interstate natural gas pipeline system, most companies stopped using coal gasifiers and switched to natural gas burners, which are more convenient to use.

Since the 1973–1974 oil embargo, the price of energy has significantly increased and industrial users have occasionally experienced difficulties obtaining reliable supplies of fuel. Consequently, interest has increased in low-Btu coal gasification as a means of securing a reliable source of fuel. As of July 1979, in the United States, six low-Btu gasifiers were operating, five were beginning operations, three plants were under construction, and two plants were being designed.[6] However, the combined output of the currently operating plants contributes a negligible amount of energy to current U.S. supplies.

2. MEDIUM-BTU COAL GASIFICATION

Although commercial size medium-Btu coal gasification plants are in operation overseas, none have been built in this country; hence there is no current contribution of this technology to U.S. energy supplies.

3. COMBINED CYCLE COAL GASIFICATION

Separate components of the combined cycle coal gasifier have been demonstrated; however, no fully integrated system has as yet been operated. There is, therefore, no current contribution from this technology to U.S. energy supplies.

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[5] U.S. Department of Energy. Commercialization Strategy for Industrial Atmostpheric Fluidized Bed Combustion. TID-28854 (Draft). 1978, p. 1. Subsequently cited as DOE Industrial Atmospheric Fluidized Bed Combustion report.

[6] Booz, Allen and Hamilton, Inc. "Analysis of Industrial Markets for Low and Medium Btu Coal Gasification." Washington, U.S. Government Printing Office, 1979, p. IV-2 (exhibit).

4. ATMOSPHERIC FLUIDIZED BED COMBUSTION

Approximately 20 atmospheric fluidized bed combustion units are in operation or in the design or construction stage in the United States, ranging in size from small test units to small commercial prototypes. The estimated total capacity from all of the operating units in the United States, including those which became operational during 1979, is roughly 60 Mwe. The largest of these facilities, with a capacity of 30 Mwe, is located at Rivesville, West Virginia.[7]

D. *State-of-the-Art*

1. LOW-BTU GASIFICATION

Processes and equipment for producing low-Btu gas for industrial applications are available commercially. Except for equipment improvements and changes required by environmental constraints, these gasifiers are similar to those used extensively during the 1920s and 1930s.

2. MEDIUM-BTU GASIFICATION

Although limited in the number of processes available and in the types of coal that can be used, the processes and equipment for producing medium-Btu gas are available commercially. Advanced medium-Btu gasification systems under development offer the potential of lower cost and increased capability to use Eastern coal.

3. COMBINED CYCLE COAL GASIFICATION

The separate components of this system—i.e., the coal gasifier, desulfurization processes, and combined cycle power plants fired by oil and gas—are all operational. However, no fully integrated, commercial-size, combined cycle gasifier using coal has been operated. Furthermore, a turbine operating at 2200 degrees F on the products of the gasifier is required for the system to be economically competitive; additionally, substantial technical development is still required.[8]

4. ATMOSPHERIC FLUIDIZED BED COMBUSTION

While there are still many unanswered questions regarding the large-scale utility applications of atmospheric fluidized bed combustion, the technology is ready for industrial-scale commercial prototypes. A large number of smaller industrial units are currently in operation or in the design or construction stage.

E. *Current Research and Development*

1. LOW-BTU COAL GASIFICATION

Currently, several low-Btu gasification projects are underway which involve Department of Energy (DOE), Tennessee Valley Authority (TVA), or Environmental Protection Agency (EPA) funding. These include DOE's Gasifiers in Industry Program, in which several projects are currently in operation. DOE projects include small

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[7] Ibid.
[8] DOE advanced electric generation technologies reports, p. 13.

(1 ton of coal/hr) fixed bed gasifiers without sulfur removal, and also include the sharing of costs, including the costs of three years of operation, on approximately a 50/50 basis.[9]

The DOE is also supporting development of second generation or advanced processes intended to expand the varieties of coals usable and to increase the throughput; these are at the bench or pilot plant scale and will not be ready for commercial demonstration for several years.[10] The Federal budget request for low- and medium-Btu coal gasification for fiscal year 1981 is $19 million.

2. MEDIUM-BTU GASIFICATION

The Fuel Gas Demonstration Program is the only commercial demonstration program underway in DOE for the design, construction, and operation of medium-Btu gasification systems. Under this program, two projects were selected for design, with 100 percent DOE funding. One of these projects has been selected for construction on a 50/50 cost-sharing basis. Commercial operation of the plant is not anticipated before 1985.[11] With respect to the other project, DOE has decided to continue funding design of a commercial-scale facility to process coal into medium-Btu gas which would then be converted into methanol and ultimately into gasoline. DOE is currently considering ways to assist the commercialization of this project.

Most of the other DOE-funded programs concern development of second and third generation processes and sub-systems; they are in various stages of research, bench, and pilot-plant scale development and are not expected to be available commercially until at least 1990. Furthermore, the DOE high-Btu gasification program will demonstrate some advanced processes which can also convert coal to medium-Btu gas. Industry has also been involved in developing medium-Btu gas technology.[12]

3. COMBINED CYCLE COAL GASIFICATION

Work on combined cycle gasification systems has been performed at a small-scale plant in West Germany, where gasifiers, desulfurization plants, gas turbines, and waste heat recovery steam generators have been integrated. The principal development requirements for the combined cycle system include the low-Btu combustor for near-term applications and a high-temperature turbine for later applications. The DOE currently sponsors development to achieve turbine firing temperatures into the 2600 degree F range, and engine tests are expected on low-Btu gas during the 1980–84 period.[13] No Federal funds have been requested for this work for fiscal year 1981.

4. ATMOSPHERIC FLUIDIZED BED COMBUSTION

Only one pilot plant (DOE-sponsored), with a 30 MWe capacity, has been operating in this country in a utility environment; howev-

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[9] DOE low-Btu gasification report, p. 7.
[10] Ibid.
[11] DOE medium-Btu gasification report, pp. 4–5.
[12] Ibid., p. 5.
[13] DOE advanced electric generation technologies report, p. 14.

er, certain other DOE efforts support utility and industrial applications. These include basic studies, development of improved processes, mathematical modelling, installation of a coal feed test unit, planning for a materials test unit, and conceptual design work for a full-scale utility demonstration plant. There are also several related industrial atmospheric fluidized bed projects underway for various applications and plant sizes; it is expected that experiences gained from these projects will also apply to some extent to utility applications.[14] The Federal budget request for fiscal year 1981 amounts to $37.2 million.

In addition to these DOE-supported efforts, the United Kingdom and the U.S. private sector have supported development efforts on this technology. Financial and technical commitments have been made by boiler suppliers, architect-engineers, industries, utilities, and trade associations.[15] For utility applications, the Tennessee Valley Authority has undertaken a program to demonstrate atmospheric fluidized bed technology at a size suitable for baseload power generation. DOE will support TVA's effort by providing technical data.

II. Prospects or Requirements for Further Development

A. *Research and Development*

1. LOW-BTU COAL GASIFICATION

Although gasifiers and components for this technology are commercially available now, additional research and development could advance larger throughput systems cost improvements. In terms of starting a U.S. industry, commercialization of existing systems, is judged to be the most crucial step at this time (see II.C, below).

2. MEDIUM-BTU COAL GASIFICATION

First generation processes and equipment for producing medium-Btu gas from coal are available commercially. Research and development activities on second and third generation processes could yield improvements in operating cost; however, these processes will not be ready for the market for several years.

3. COMBINED CYCLE COAL GASIFIER

Although the combined cycle system can use commercially proven technology, substantial technical development, especially in high temperature gas turbines and in low-Btu combusters, could be used to improve reliability of existing systems. As discussed in section III C, continued work on emission control technology for combined cycle systems also appears necessary.

4. ATMOSPHERIC FLUIDIZED BED COMBUSTION

Operation of coal-fired atmospheric fluidized bed combustion units has been fully demonstrated, on a small scale, in this country and overseas; however, research and development efforts on var-

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[14] Ibid., p. 2.
[15] Ibid.

ious materials and components used in this technology are needed. In particular, research and development is required on: (a) industrial-scale boilers and heaters for more reasonable cost and improved performance and reliability, and (b) coal feed facilities.

B. Demonstration

1. LOW-BTU COAL GASIFICATION

Low-Btu gasifiers have been proven technically, and at least eight different types of gasifiers are commercially available, ranging in capacity from one to 45 tons of coal per hour. These systems have been demonstrated commercially in various parts of the world in a number of applications.[16] Successful demonstration of this technology in numerous applications could convince hesitant potential users of the benefits of this technology.

2. MEDIUM-BTU COAL GASIFICATION

Although there are over 100 medium-Btu gasification plants operating overseas, there are no commercial plants in the United States today. Thus, operation of a medium-Btu demonstration plant, whose design, construction, and operation are currently planned, is needed to promote the commercialization of this technology in the United States.[17]

3. COMBINED CYCLE COAL GASIFICATION

Although the separate system parts are operational, no demonstrated full-scale integrated gasifier and combined cycle plant is operational. A small-scale demonstration plant has been in operation in West Germany for several years; however, further technical developments could aid successful construction and operation of such a facility in the United States.

4. ATMOSPHERIC FLUIDIZED BED COMBUSTION

Small industrial atmospheric fluidized bed combustion units have operated successfully, demonstrating the practicability of fluidization, combustion efficiency, sulfur oxide removal, and steam generation. However, a reliable full-sized demonstration plant, providing validated operational and economic characteristics, is essential before the utility sector will assume the risks of this new technology.[18] Uncertainty exists about the long-term operating performance of these units for utility use because large units have not yet been successfully demonstrated in a commercial environment.

C. Commercialization

1. LOW-BTU AND MEDIUM-BTU COAL GASIFICATION

Industry is convinced that both low-Btu and medium-Btu coal gasification do not currently provide a clear economic advantage over conventional fuels. Early adopters face substantial risks due

[16] DOE low-Btu gasification report, p. 6.
[17] DOE medium-Btu gasification report, p. 4.
[18] DOE advanced electric generation technologies report, p. 6.

to lack of operating experience, uncertainty regarding equipment costs, lack of data on plant retrofit requirements, and uncertainties over Federal policies regarding energy pricing and environmental restrictions.[19]

The Federal Government's role in the advancement of low-Btu and medium-Btu coal gasification currently includes support of several of the first commercial demonstration plants to be built (in recent times) and the dissemination of data to both industry and the public. However, the Federal Government plans to play an increasingly active role in promoting the commercialization of these technologies. Using authorities and appropriations contained in Public Law 95-238, Public Law 96-126, and legislation creating the United States Synthetic Fuels Corporation (SFC), which will be a Federally-supported, primarily financially-geared entity, the Department of Energy and the SFC could expedite the commercialization of low-Btu and medium-Btu coal gasification by offering an array of incentives, such as price guarantees, purchase agreements, loan guarantees, project feasibility studies, and cooperative arrangements. Under generally accepted forecasts of energy prices and supply, Federal initiatives/incentives will be the principal factor to accelerate the market penetration-commercialization of low-Btu and medium-Btu coal gasification.[20]

2. COMBINED CYCLE COAL GASIFICATION

Commercial implementation of combined cycle power systems will require substantial investments before the technology is considered acceptable to utilities for private investment. This early investment has been estimated at $500 million to $1 billion. The following conclusions on the readiness of this technology have been stated (in draft form) by the DOE task force on commercialization for advanced electric generation technologies:

(*a*) Although this technology can use commercially proven components, greater benefits could be achieved with high temperature gas turbines now being developed.

(*b*) The present state-of-the-art is not competitive with other concepts, e.g., conventional coal with a scrubber or atmospheric fluidized bed combustion.

(*c*) Since uncertainties are costly to resolve, development and demonstrations are needed.

(*d*) Potential for this technology is high, but business risk will hinder commercialization.

(*e*) Further development should precede commercialization.[21]

3. ATMOSPHERIC FLUIDIZED BED COMBUSTION

Early acceptance and use of this technology by industry is critical to its adoption and the consequent rate of market penetration. However, acceptance is highly dependent on satisfactory demonstration to potential users. A major problem facing this technology is that many industrial users are reluctant to risk current productive capacity to promote this uncertain technology, regardless of

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[19] Booz, Allen & Hamilton, Inc., p. 19.
[20] Booz, Allen & Hamilton, Inc., p. 22.
[21] DOE advanced electric generation technologies report, p. 18.

savings which might accrue. However, once this technology has been proven reliable in a variety of industrial uses and can meet U.S. pollution standards, it seems likely that companies now utilizing conventional fuels might switch to atmospheric fluidized bed combustion. In the DOE draft study, it was recommended that industry build and operate the demonstration units, thus providing, with maximum credibility and technology transfer, the experience and data on performance, cost, reliability, emissions, and waste disposal.[22]

Because of the diverse composition of the industrial boiler market and wide differences in end-use applications, a variety of actions is likely to be needed to overcome all market barriers to the use of atmospheric fluidized bed combustion. Consequently, DOE officials have offered the following recommendations:

(*a*) Build 4 commercial-scale industrial prototype units in four different industries on a cost-shared basis.

(*b*) Impose an oil tax and provide for industrial gas price increases to reduce the economic advantages of these fuels vis-a-vis coal.

(*c*) Clarify the intent of the Environmental Protection Agency on industrial standards and firm up these standards as soon as possible.

(*d*) Continue the existing industrial applications program.

(*e*) Initiate a detailed survey of the small boiler and process heater markets to provide a data base for penetration of these markets.[23]

The DOE strategy proposed for achieving commercialization of atmospheric fluidized bed combustion for utility purposes includes the following actions:

(*a*) Initiate development of a 200 MWe demonstration atmospheric fluidized bed combustion plant, expected to be on-line by 1985;

(*b*) Start the development of an early plant risk reduction program by examining all alternatives, selecting those deemed most appropriate and capable of implementation, and strive to implement them; and

(*c*) Verify the present tentative conclusion that full-scale atmospheric fluidized bed combustion will not require a scrubber to meet current and proposed environmental standards.[24]

III. Potential Obstacles to R. & D. or Technology Implementation

A. *Low-Btu Coal Gasification*

The most significant barriers to commercialization of low-Btu gasification, according, to DOE, include the following:

(*a*) Current availability of cheaper fuels and the expectation that fuels, such as oil and natural gas, will continue to be available and remain cheaper in the future;

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[22] DOE industrial atmospheric fluidized bed combustion report, pp. 34-35.
[23] Ibid., p. 36.
[24] DOE advanced electric generation technologies report, p. 28.

(*b*) The lack of current Federal environmental standards for low-Btu gasification and the fear that, once standards are established, they will be changed;

(*c*) Lack of sufficient operating experience with interaction between gasification and specific end use applications;

(*d*) Uncertainty of costs to design, build, and operate a plant and of the cost of the gas produced, particularly a problem when extensive gas clean-up is required; and

(*e*) The risk of being the first in a specific industrial application, in view of the uncertainties of cost, lack of experience, and changes in environmental regulations.[25]

B. Medium-Btu Coal Gasification

According to DOE, the most significant barriers to commercialization of medium-Btu gasification include the following:

(*a*) Need for development of a fuel pricing policy that will encourage the conversion to coal and the reduction of oil imports;

(*b*) The lack of Federal environmental standards for this technology and the fear that, once standards are established, they will be changed;

(*c*) Current availability of cheaper fuels and expectations that fuels such as oil and natural gas will be available and remain cheaper in the future;

(*d*) The lack of operating experience and technology application experience for potential users to evaluate, since there are no medium-Btu gasification plants in the United States;

(*e*) Uncertainty of the costs to design, build, and operate a plant and of the cost of the gas produced; and

(*f*) The risk of being the first in a specific industrial application, in view of uncertainties of cost, lack of experience, and lack of and potential changes in environmental regulations.[26]

C. Combined Cycle Coal Gasification

The basic barriers to commercialization of the combined cycle gasifier concept are technical, environmental, and institutional. Technical obstacles cited by DOE include the fact that the following systems and sub-systems do not yet exist:

(*a*) A demonstrated full-scale operational integrated gasifier and combined cycle plant;

(*b*) A fully-developed combustor using low-Btu gas;

(*c*) Commercially available entrained bed gasifiers to handle caking coal; and

(*d*) A developed and demonstrated high temperature gas turbine operating on coal gas.

Technical barriers resulting from a lack of commercially-ready high temperature turbines are so great that commercialization of this technology is not possible at the present time.[27]

Further investigation of certain emission problems and development of emission control are needed to remove the following poten-

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[25] DOE low-Btu gasification report, p. 11.

[26] DOE medium-Btu gasification report, p. 9.

[27] DOE advanced electric generation technologies report, pp. 15–16.

tial environmental barriers to commercialization of the combined cycle gasification plant:

(a) Occurrence of minor sulfur compounds in the fuel gas and in tail gas discharged into the atmosphere (although the Selexol process does remove 99 percent of the hydrogen sulfide from the fuel gas); and

(b) Generation of thermal nitrogen compounds and particles (soot) in the combustor.

It is expected that improvements in emission controls developed for alternate power systems could also be applied effectively to the combined cycle plant.[28]

Two barriers could impede use of the combined cycle gasification plant. One obstacle is the tendency for the Federal Government to continue changing emission standards, thus defeating prospects for plant standardization and associated capital cost reductions. The second institutional barrier is the significant risk associated with utilization of a technology more complex than any other system which electric utilities have experienced.[29]

D. *Atmospheric Fluidized Bed Combustion*

Barriers to the commercialization of industrial atmospheric fluidized bed combustion are technical, economic, environmental, and institutional. These obstacles are summarized below:

1. OPERATING PERFORMANCE

(a) No large-scale atmospheric fluidized bed combustion units are in commercial operation in the United States.

(b) Industrial users will not risk production operations on a technology not demonstrated at, or close to, commercial scale in commercial operations.

(c) Commercial demonstration plants are needed to reduce uncertainty and risks related to costs and environmental performance.

2. CHEAP OIL AND GAS

(a) At today's prices, it is still cheaper to burn oil and gas to produce steam because of the much higher investment required for coal-fired atmospheric fluidized bed combustion or conventional boilers.

(b) Although cost increases and uncertainty about future supplies will decrease the desirability of oil and gas as large industrial boiler fuels, on an economic basis use of these fuels will not be eliminated.

3. CAPITAL COSTS

(a) Atmospheric fluidized bed combustion or conventional coal-fired boilers cost three to five times as much as oil/gas boilers.

(b) Atmospheric fluidized bed combustion costs are uncertain, pending experience with commercial units; however, it is estimated that 80 percent of commercial unit costs will be derived from common, conventional equipment and costs of the units unique to this technology will comprise 20 percent of the total costs.

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[28] Ibid., p. 16.
[29] Ibid., p. 17.

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4. RELIABILITY DATA

(*a*) No data are available on commercial-scale operating performance. Major potential user industries require continuous operation 24 hours per day and 350 days per year.

(*b*) Industry will not install critical boilers on speculative performance data.

5. ENVIRONMENTAL BARRIERS

(*a*) No standards now exist for industrial boilers with a capacity of 250 million Btu per hour, and delay in setting standards is a deterrent to investment decisions.

(*b*) Industry wants assurance that, if atmospheric fluidized bed units are installed, they will not become uneconomical because of future environmental standards.

(*c*) Atmospheric fluidized bed combustion generates large amounts of dry, alkaline waste from use of limestone, and future disposal needs are difficult to evaluate, owing to uncertainty about leaching of these wastes.

6. LIMESTONE CHARACTERISTICS

(*a*) Though widely available, limestone varies in sulfur dioxide absorption characteristics and must be evaluated for use in atmospheric fluidized bed combustion on a case-by-case basis.

7. BOILER MANUFACTURER INTEREST

(*a*) Several major boiler manufacturers are not yet actively seeking industrial atmospheric fluidized bed combustion business.[30]

Many of the barriers stated above for industrial use of atmospheric fluidized bed combustion also apply to commercialization of this technology in the electric utility field. Such barriers, as specifically related to utility application, are listed below:

(*a*) Need for a validated demonstration of reliability, economic, and environmental characteristics.

(*b*) Improvements in coal feed, in-bed high temperature materials, carbon utilization, and boiler operation and control.

(*c*) Willingness of utilities to assume the risks associated with the new technology in view of uncertainties about operations and regulations applied to utilities.

(*d*) Uncertainties about environmental standards.[31]

IV. Potential Contribution to Future U.S. Energy Supplies

Anticipated contributions of the four technologies discussed above to U.S. energy needs in 1985, 1990, and 2000 as summarized by DOE are given in table 4.

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[30] DOE industrial atmospheric fluidized bed combustion report, pp. 41–46.

[31] DOE advanced electric generation technologies report, pp. 2, 9–10.

TABLE 4.—ESTIMATED CONTRIBUTIONS TO U.S. ENERGY NEEDS FROM OTHER TECHNOLOGIES FOR THE UTILIZATION OF COAL

[In quadrillions of Btu's]

Technology	1985	1990	2000
Low-Btu coal gasification [1]	0.01	0.16–0.2	1.0
Medium-Btu coal gasification [2]	0.04	0.3–0.5	1.0–4.4
Combined cycle coal gasifier [3]	0	0.1	3.0
Atmospheric fluidized bed combustion:			
Industrial [4]	0	0.1	3.0
Electric utility [3]	0.15	0.7	3.0
Total	0.20	1.36–1.6	11.0–14.4

[1] U.S. Department of Energy. Commercialization strategy report for low-Btu gasification, p. 8.
[2] U.S. Department of Energy. Commercialization strategy report for medium-Btu gasification, p. 6.
[3] U.S. Department of Energy. Commercialization strategy report for advanced electric generation technologies, pp. 8, 15.
[4] U.S. Department of Energy. Commercialization strategy report for industrial atmospheric fluidized bed combustion, p. 17.

The uncertainty associated with these DOE projections should be recognized. As discussed below, DOE's projections may prove to be overly optimistic, especially in view of the technical, economic, environmental, lead-time, and institutional constraints facing these technologies. For illustrative purposes, an analysis of the outlook for medium-Btu gasification is presented as follows.

The DOE predicts that the expected market penetration of medium-Btu gasification by 1990 will be .3–.5 Quads, which would be produced by 30–50 plants. Currently, there are no medium-Btu gasification plants operating in the United States. Data from available press releases indicate that few companies are now proceeding with these plants. The 1985 market for these plants is expected to consist of, at most, two or three plants.[32] The lead times associated with commercialization are quite lengthy. Design work for one project began in 1977, and commercial operations are planned to begin around late 1985. The initial plants are to serve as test projects for other companies which are generally waiting on the results of these early efforts.[33] In view of the long lead times necessary to construct a commercial plant, the uncertainties facing this industry (such as questions regarding future Federal environmental and economic policies), and the current and anticipated level of industrial activity, it seems highly unlikely that 30 plants will be completed by 1990, as projected by DOE.

[32] Booz, Allen & Hamilton, Inc., p. VII–22.
[33] Thakkar, Pravin. "Memphis Industrial Fuel Gas Demonstration Project." Gas Energy Review. American Gas Association. April 1980: I.

DIRECT SUNLIGHT TECHNOLOGIES

AGRICULTURAL AND INDUSTRIAL PROCESS HEAT APPLICATION OF SOLAR ENERGY *

I. SURVEY OF CURRENT SITUATION

A. Description of the Technology

Solar collector systems for agriculture and industrial process heat applications produce hot air, hot water, and steam within three primary temperature ranges: low (less than 212 degrees F); intermediate (212 to 350 degrees F); and high (greater than 350 degrees F). Much of the technology for agricultural and industrial applications is adapted from solar heating and cooling systems, particularly for low-and-intermediate-temperature requirements. For higher temperatures, the applications draw from high-concentration collectors developed for the solar thermal electric program.

Agricultural and industrial energy requirements account for approximately 39 percent of the total energy used in the United States.[1] Industrial energy consumption in 1979 totaled approximately 29 quads of primary energy, or about 37 percent of the national total;[2] agriculture used an estimated 1.3 quads in 1978, or about 2 percent of our national consumption.[3] About 16 percent of the energy consumed in agriculture is for livestock shelter heat (11 percent) and crop drying (5 percent).[4]

Of the energy consumed in the industrial sector, approximately three percent is used at temperatures of less than 212 degrees F, 32 percent is used at temperatures betwen 212 degrees F and 350 degrees F, and 65 percent is used at temperatures above 350 degrees F.[5] Existing or near-term solar technologies can achieve temperatures in the low and intermediate range required for many agricultural and industrial and applications.

B. Known Resources and Reserves

Solar energy is essentially inexhaustible. However, limitations on the availability of materials which make up the collectors and other components of agricultural and industrial heat systems could limit the rate of application should the demand for these systems become great.

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* Prepared by J. Glen Moore, analyst in energy technology.

[1] Solar Energy for Agriculture and Process Heat. DOE. September 1978.

[2] Department of Energy Solar Energy Objectives Calendar Year 1980. DOE/CS-0155. Part V, Solar Energy in the Industrial Sector. 1980, p. 168.

[3] Ibid. Part IV, Solar Energy Use in the Agricultural Sector, p. 137.

[4] U.S. Department of Agriculture. USDA Energy Policies: Price Impacts on the U.S. Food System. USDA Agricultural Economic Report No. 407 (1978).

[5] Domestic Policy Reviews of Solar Energy. Final Report [of the] Research, Design and Development Panel. DOE October 1978.

C. Current Contribution to U.S. Energy Supplies

Aside from greenhouse heating which has always been a solar function, a small commercial market is developing for certain agricultural solar applications such as crop dryers. On the whole, however, agricultural and industrial solar applications are considered experimental and are not making a contribution to U.S. energy supplies at this time.

D. State-of-the-Art

1. AGRICULTURAL APPLICATIONS

Current solar conversion applications in agriculture are limited primarily to grain drying, crop drying, food processing, and animal shelter heating. The temperature requirements for these applications are moderate (generally below 120 degrees F) and can be met with currently available active or passive collector systems similar to those employed in residential heating and cooling applications. After direct heating, irrigation pumping for crop production is the second largest direct energy requirement in agriculture. The use of solar energy systems for irrigation is promising, but this application requires concentrating collectors and vapor-cycle engines which are not yet commercially feasible.

2. INDUSTRIAL APPLICATIONS

Industrial process heat is defined as thermal energy used directly in the preparation and/or treatment of materials and goods produced by mining and manufacturing processes. In practice, process heat can be hot water, low-pressure steam, or hot, dry air. State-of-the-art flat-plate collectors can satisfy many low-temperature industrial requirements. Collectors for intermediate temperature requirements are technically advanced but still not ready for widespread commercial application. For high temperature requirements, however, collector technology is not well advanced, with technical feasibility of components, subsystems, and systems limited largely to prototype demonstrations.

E. Current Research and Development

A Federal program for agricultural and industrial process heat applications has been underway for several years. The general program strategy for both industry and agriculture has been to emphasize systems based on state-of-the-art components (predominantly low-temperature, flat-plate collectors), rather than systems whose components require significant research and development efforts. It has been assumed that Federal R. & D. expenditures within other programs, notably those in solar heating and cooling and solar thermal electric technologies, would provide the necessary systems R. & D. required for intermediate and high-temperature applications in the mid-to-long-term.

The Department of Agriculture manages a series of cost-shared demonstration experiments and prototype systems development projects for DOE. The program now consists of approximately 50 projects taking place under a variety of climatic conditions. These projects include agricultural food processing, grain drying, and the heating of livestock shelters and greenhouses.

In the industrial applications area, DOE is sponsoring a series of projects to demonstrate state-of-the-art low- and intermediate-temperature solar systems for diverse industrial processes. Increased effort is only now beginning to be directed toward high-temperature collectors. And while high-temperature collectors are complex and not well developed, such efforts are considered important to furthering agricultural and industrial uses because the potential market is broadened as the temperature capability of the solar system increases.

The DOE received $14 million for the Agriculture and Industrial Process Heat Applications Program in fiscal year 1990; an additional $15 million was earmarked under the DOE Systems Development Program to support this activity, bringing the total Federal budget for agricultural and industrial process heat to $29 million in fiscal year 1980. The fiscal year 1981 request, post-revision, amounts to $38.1 million.

Other nations are interested in agricultural and industrial heat applications of solar energy and are proceeding with the development and testing of systems similar to those being investigated in the United States, but at a substantially lowered level of effort.

II. Prospects or Requirements for Further Development

The long-term prospects for solar process heat are dependent on R. & D. program efforts, because in the long-term, use will be determined primarily by solar system costs and particularly by collector costs. These costs might be reduced by a program which concentrates on fundamental research and development that can lead to significantly improved, lower cost collector systems, although other cost-reducing approaches might be as effective. Because of the costs involved and the uncertainty of future markets (especially for intermediate- and high-temperature industrial systems), it is unlikely that the solar industry will be willing or able to conduct its own R. & D. for advanced systems as it did for solar building applications. Therefore, a predominant Federal role in R. & D. is seen as a major requirement for moving these applications into commercial use. Further, the high capital costs for agricultural and industrial process heat systems, leading to a rather poor return on investment, indicates a broad Federal program of financial and investment incentives will be required if commercialization is to proceed at a quick pace.

III. Potential Obstacles to R. & D. or Technology Implementation

The widespread implementation of agricultural and industrial applications faces many of the same obstacles identified for solar heating and cooling of buildings. However, several additional points must be considered regarding agricultural and industrial process applications:

A. Technical

Industrial process heat technology for the 350 degree F and higher range has only been demonstrated in prototype. Rigorous R.

& D. is needed in relevant subcomponent areas, including structures, coatings, reflectors, and controls as well as systems engineering for low cost manufacturing, assembly, and installation. A low level of technological development for high-temperature components and systems means the exclusion of about 70 percent of the process heat market where direct applications might be considered, thus reducing significantly the commercialization potential of industrial process heat.

B. Economic

1. PAYBACK REQUIREMENTS

Industry requires short payback periods for new process systems, generally from three to five years, and a high internal rate of return for capital investment. At this time, solar technology performs poorly in both respects. Solar industrial process heat systems, like most solar technologies, are characterized by high initial costs and long payback periods. It is estimated that energy from first generation intermediate-temperature solar industrial units will cost two to three times more than it would cost to use residual fuel oil.[6] Payback and return on investment may not be as critical for agricultural solar application but will still be a limiting factor. Federal and State economic incentives can be useful in bringing about early acceptance of both agricultural and industrial solar energy systems.

2. FEDERAL CORPORATE TAX POLICY

Under corporate tax law, firms are allowed to deduct as a business expense the cost of fuels such as oil, natural gas, and electricity. These costs are deducted from gross income, which means the income which pays for fuel is not taxed. Consequently, fuel cost savings from a solar installation, in effect, are taxed as company profits. Reducing costs by cutting fuel bills adds to the taxible income and only a portion of the cost of solar equipment as a capital investment can be deducted for depreciation. Federal tax policy that allows deducting fuel expenses from gross income while treating solar equipment as a capital investment, could be a major disincentive to solar investments for these applications.

C. Environmental

N/A.

D. Social

N/A.

E. Political

The Federal solar program deals with the agricultural and industrial sectors as a single entity, though it is increasingly clear that the nature of applications, technology, and problems may be markedly dissimilar in the two sectors. Furthermore, the rate of market penetration of the two may also be dissimilar, with agricultural applications likely to proceed at a faster pace than industrial applications. The market prospects of both might be improved by a separate management structure within DOE for each application.

[6] Domestic Policy Review of Solar Energy. DOE. February 1979.

F. Land Requirements

Many large process energy users operate 24 hours a day, 365 days a year. Their energy requirements can be very large and unless extremely large areas of collectors (in excess of available roof area) are considered, solar process heat may contribute only a small fraction of the total required energy of a given industrial plant. Large industrial energy users may not be interested in an energy system which is so limited. Therefore, requirements for suitable land area for collectors near industrial plants could be a substantial market barrier; such requirements should not be a problem for agricultural applications, however.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Solar energy technology and manufactured hardware are available for low and intermediate temperature applications in agriculture and industry. However, solar systems typically have not been competitive to date and their long-term operating experience needs to be observed.

In agriculture, the major markets for solar thermal energy systems are in irrigation pumping, crop drying, and greenhouse and livestock shelter heating. Solar energy can make a potentially significant contribution to these markets, however, since energy use in the agricultural sector is relatively small (1.3 quads in 1978), even a significant contribution would have little impact on national energy consumption. The contribution of solar thermal energy systems to the agricultural sector probably will be negligible in 1990.[7]

The industrial sector can use solar thermal energy for both electricity and heat, with the largest ultimate impact expected to come from the production of industrial process heat.[8] Solar thermal devices now provide virtually no energy in the industrial sector; by 1990 DOE estimates these systems will save the energy equivalence of 1 quad in primary fuels.[9]

B. Contribution by 2000 or Beyond

DOE estimates that the agricultural sector will save the energy equivalence of 0.2 quads in the year 2000 from the use of solar thermal devices for irrigation pumping (0.08 quads), crop drying (0.1 quads), and greenhouse and livestock shelter heating (0.03 quads).[10]

Aided by the Power Plant and Industrial Fuel Use Act,[11] which encourages the use of solar thermal systems by establishing prohibitions against the consumption of large amounts of oil and natural gas in industry and utilities, the use of solar thermal systems in the industrial sector is expected to show steady growth through the

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[7] Department of Energy Solar Energy Objectives, Calendar Year 1980. DOE/CS-0155. April 1980, p. 141.

[8] Ibid., p. 171.

[9] Domestic Policy Review of Solar Energy. A Response Memorandum to the President of the United States. DOE. TID-22834. February 1979, fig. 4.

[10] Op. cit.

[11] 42. U.S.C.A. par. 6211 (Supp. 1979).

1990s. By the year 2000 DOE estimates industry will save the energy equivalence of 2.0 quads of primary energy from the use of solar thermal electric and process heat systems.[12]

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[12] Op. cit., p. 171.

PASSIVE SOLAR ENERGY *

I. Survey of the Current Situation

A. Description of the Technology

Passive solar heating and cooling is a technology for heating and cooling of interior spaces. It is distinguished from active solar technology by its use of the structure of a building to collect, circulate, and store solar thermal energy for use in the building. Active solar technology uses mechanical appliances connected by conduits filled with a fluid which is pumped around with the aid of external power. The external power may be, but need not be, electricity from photovoltaic cells or other solar electric power technologies.[1]

Passive solar heating and cooling may also be distinguished from solar electric power technologies. Such technologies produce electric power from sunlight either directly, from the light-sensitive plates of photovoltaic cells, or indirectly—for example by heating water to produce steam for a steam-powered electric generator.

The following discussion will concentrate on the uses of passive solar energy in heating and cooling homes.[2]

A home may be defined as any construction in which one human family unit lives, whether an apartment, mobile unit, cottage or house—provided it includes its own cooking facilities, and is capable of year-round habitation. Apartment units and mobile homes are thus specifically included in the definition of a home.

Homes may be described in four classifications according to the way they use or disregard the heat available from sunlight and the cooling available from natural ventilation. These are: conventional, energy-efficient, sun-tempered, and true passive solar.[3]

1. THE CONVENTIONAL HOME

A conventional home is one whose design includes no feature whose main purpose is using sunlight for home heating. Nearly all conventional homes have some windows which have been provided for lighting in the daytime, and for a view. These windows admit and capture a small amount of heat from the sun. When the curtains are open and the glass is closed, warm sunlight freely enters—and the interior air, warmed by the sunlight, is kept from escaping. When the curtains are closed and the glass is open, less

*Prepared by David Hack, analyst in energy technology.

[1] Some solar buildings incorporate both passive and active solar heating and cooling features. These buildings are called hybrid solar buildings.

[2] Although passive solar technology is applicable to some industrial purposes, for example the heating and cooling of warehouses, the present analysis is limited to homes as here defined. This is done in part to keep the analysis within a manageable scope, and in part because data on the heating and cooling of industrial spaces are difficult to separate from the energy used in industrial processes.

[3] U.S. Department of Housing and Urban Development. The First Passive Solar Home Awards. Washington, U.S. Government Printing Office, January 1979, 226 p.

sunlight is admitted, and that which does enter to warm the room is carried away by air flowing around the curtain and through the open glass. This prevents the interior of the home from becoming warmer than the air outside.

2. THE ENERGY EFFICIENT HOME

An energy efficient home is similar to a conventional home, except that unusual care is taken in its design and construction to insulate the exterior walls, the ceilings, and the floor, foundation or basement. Extra care is also taken in the energy efficient home to weatherstrip windows and doors, and to seal or caulk many hidden cracks and joints which in a conventional home are sources of air infiltration.

3. THE SUN-TEMPERED HOME

The sun-tempered home is like the energy-efficient home in careful attention to insulation, weatherstripping and sealing; but it often differs substantially from both the conventional and the energy-efficient home in appearance. The sun-tempered home looks different because it is designed with extra large south-facing windows to take increased advantage of the heat available from the sun in the winter. These windows usually include some provision for shading from the sun during the summer, to minimize the need for mechanical cooling equipment. The north-facing windows of a sun-tempered home are fewer in number and smaller in area than those of a conventional or energy-efficient home. East- and west-facing windows are also limited in number and size in the sun-tempered home, and often will include special blinds or shutters.

4. THE TRUE PASSIVE SOLAR HOME

The true passive solar home includes the features of both the energy-efficient and the sun-tempered home—and adds to them the designed-in presence of greatly increased thermal storage mass. This mass may be of masonry, sand, water or other material which is cheap and dense and able to absorb and hold a lot of heat for a period of time, thus damping daily temperature swings. The passive solar home also provides for circulation of warm or cool air by natural air currents, and for direct transfer of heat between the thermal mass and human bodies by infrared radition.

Passive homes have natural air currents which—with vents to the outside closed—circulate and distribute the heat of the storage mass throughout the home.[4] In warm weather, with vents to the outside open, prevailing winds may flow through the home. This air flow is especially effective for cooling in climates with cool nights. Air currents must be designed into the very architecture and structure of the building. Any supplementary mechanical circulation which is provided must be designed to work with, rather than against, the air flow which results from the basic building design. Aided by proper opening and closing of air vents and sun shades, the same thermal storage mass which warms the house

[4] The word "vent" includes windows which may be opened, as well as non-window vents.

through winter nights helps cool the house through summer afternoons.

Therefore, as noted by the Department of Housing and Urban Development (HUD),[5] the best passive solar design is not an add-on item. It involves the whole structure. It is embedded in the architectural concept of the structure before the foundation is dug, or—in the case of a manufactured mobile home, before the assembly line is laid out.

B. Known Resources and Reserves

Elsewhere in this study, solar resources and reserves are described as inexhaustible in principle, since they come from the sun. The practical limit on using energy from the sun is described in other chapters as arising from the quantities of materials, equipment and facilities available for the use of solar energy—not as arising from the nature of solar energy or the sun itself.

The present chapter defines the "known resources and reserves" of passive solar energy for home heating and cooling in terms of the "facilities available" in the form of homes to be heated (or cooled). The concept of treating energy saved through conservation or solar displacement as energy "produced" by conservation or solar techniques is accepted in conventional practice and needs no justification here. The resources of energy available from passive heating and cooling of homes are defined here as the flow of energy which would be required in home heating and cooling, if passive solar technology were not employed. The known reserves of passive solar energy are defined here as that flow of energy which theoretically could be conserved by application of passive solar technology to all homes constructed in the future, as well as (to the extent possible) through retrofit or replacement of all existing homes.

The United States used 78 quads of primary energy in 1978.[6] Of this total use about 8.6 quads was used for the final purpose of space heating of residences.[7] As defined above, the resources of passive solar energy for home heating are therefore 8.6 quads per year. The energy reserves available in principle from passive solar home technology will be seen subsequently in this section to be a little less than 8.6 quads annually.

In the conventional home, about 5 percent of the total requirement for space heat is met by direct and indirect sunlight. The sunlight enters the home through windows, even though the windows have not been designed primarily for solar heat collection. We assume that the U.S. housing stock in 1978 approximated, on the average, the performance of the conventional home. Then the 8.6 quads of primary fuel used to heat U.S. homes in 1978 would account for about 95 percent of the total space heat input. The total space heat input would be about 9.0 quads, 5 percent from sunlight and 95 percent from fuel.

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[5] Op. cit., p. 2.

[6] U.S. Energy Information Administration. Annual Report to Congress, 1978. Vol. 2. Washington, U.S. Government Printing Office 1979, 202 p. The total energy consumption figure appears on p. 3 and p. 7.

[7] Resources for the Future. Energy in America's Future: The Choices Before Us. Baltimore, The Johns Hopkins University Press. 1979, 555 p. The residential space heating figure appears on p. 127.

The Department of HUD estimates that an average energy efficient home would get about 10 percent of its heat from direct solar gain, and about 90 percent from conventional fuel. Although the amount of heat gained by sunlight coming through the windows is the same as in the conventional home, since the total heat input required is about half that of a conventional home, the heat coming in the windows is 10 percent rather than 5 percent of the total.

According to HUD, the average sun-tempered home requires about the same total heat input as the energy efficient home, but it gets 25 percent, instead of 10 percent, from the sun. So about 75 percent instead of 90 percent of its heat comes from fuel.

The average passive solar home—as a consequence of its greater mass of masonry, sand, gravel or water—uses the sunlight it receives more efficiently than the sun-tempered home. Although the passive solar home requires as much total heat input as the sun-tempered and energy-efficient homes, it gets 75 percent of its total heat from sunlight falling upon the thermal mass—in which it is stored and from which it is released during the night.

Retrofit tightening of the thermal envelope and retrofit sun shading and sun opening of existing homes are not contributions unique to passive solar energy, as defined by HUD. They are, however, energy conservation steps which on a national scale are appropriate for first action, just as design of a tight thermal envelope, and provision of openings to the sun, and sun shading, are initial prerequisites in an individual passive solar home. If the Nation is to make substantial use of passive solar energy to reduce its consumption of fuel, one may think of the national stock of all homes as a passive solar designer thinks of a single passive solar home: All homes meeting minimum standards for human habitation have a thermal envelope. The thermal envelope may range from very poor to very superior. Many homes recently built in the United States fall far below their maximum cost-effectiveness potential in terms of reducing the need for conventional home heating through insulation, sealing, caulking, storm windows, shutters and other small features and "fixes."[8] At least two studies conclude that total residential space heating requirements can be reduced by about 50 percent through energy efficiency measures alone.[9]

Table 5 shows that if such energy efficiency in the U.S. housing stock were accomplished, residential space heating requirements would be about halved, from 9.0 quads annually to 4.5. If the housing stock could on average achieve the HUD performance definition of the sun-tempered home, the annual contribution from sunlight would be increased by 0.7 quads. If the housing stock were made finally to reach, on the average, the performance of a "passive solar" home, the additional heating from the passive solar features would be about 2.2 quads. This is the maximum theoretical contribution; it could be approached only by replacement of most of the existing housing stock. The rate at which these technologies may be phased in is discussed in section IV. The maximum

[8] For example see Energy and Buildings, vol. 1, No. 3, April 1978: 201–343.

[9] Stobaugh, Robert, and Daniel Yergin, ed. Energy Future. [Report of the Energy Project at the Harvard Business School.] New York, Random House. 1979. 353 p. See p. 170 and footnote, 72, p. 312.

theroretical contributions from the steps leading to passive solar energy are summarized in Table 5. The incremental annual savings tabulated in column 1, and the cumulative annual savings tabulated in column 2, are the reserves available from use of these technologies. The outer bound of these reserves is 7.4 quads per year.

TABLE 5.—SUMMARY OF KNOWN RESOURCES AND RESERVES AVAILABLE FROM STEPS LEADING TO A PASSIVE SOLAR HOUSING STOCK

[In quadrillion Btu's]

	Incremental annual saving	Cumulative annual saving	Conventional fuel consumed annually	Annual solar heating	Total heat input
Conventional housing stock (1978 fuel use)			8.6	0.4	9.0
Energy efficient housing stock	4.5	4.5	4.1	0.4	4.5
Sun-tempered housing stock	0.7	5.2	3.4	1.1	4.5
Passive solar housing stock	2.2	7.4	1.2	3.3	4.5

C. Current Contribution to U.S. Energy Supplies

At present, passive solar technology has barely begun to penetrate the new home market in the United States. Although home builders across the Nation have entered the market with energy-efficient homes or sun-tempered homes, the truly passive solar home represents probably no more than a few hundred of the 2 million or so new homes built annually today.

D. State-of-the Art

The basic principles of passive solar technology as applied to homes have been known for centuries. The U.S. Pueblo Indians, for example, constructed multi-tiered villages of hardened mud (adobe), sheltered from the summer sun by overhanging cliffs. These villages provided shading from the high summer sun, heating from the low winter sun, and thermal mass to extend the night coolness into the summer day, and the winter sun/warmth into the cold night. So, passive solar homes do not await the result of any crucial laboratory experiment, or any first-of-a-kind pilot plant or demonstration plant; rather, passive solar home design can be accomplished with existing common materials and ordinary construction skills.

Interest in passive solar homes is rising throughout the Nation. For example, in the summer of 1978, in response to a call by HUD for designs for passive homes, over 550 applications were submitted. Of these, 162 designs from 31 states were selected for awards—145 for new homes and 17 for "retrofit" installation of sun-tempering or passive solar elements on existing homes. Eighty of the winning home designs were being built for sale on the open market by builders who believed that passive solar designs would sell.

Recent technological developments have increased the potential contribution of passive architecture for the 1980s, compared to its contribution to stone-age cultures. These developments include the use of computers and programmable hand calculators to help create designs, and to check the performance of designs. With renewed interest in passive solar design arising in the context of more expensive conventional fuels, rapid computation methods can speed both the evolution and the transfer of passive solar design technology.

The increased sophistication and variability of passive structures made feasible by such high speed computation methods—and detailed knowledge of the physics of energy flows throughout a building structure—make the decentralized technology of passive solar energy more practical for modern buildings than when such conceptual mastery of the thermal behavior of buildings was unavailable.

II. Prospects of Requirements for Further Development

A. Research and Development

As indicated above, passive solar design is a technology which is available now; its utilization does not depend on the creation of any fundamental new scientific knowledge. Also, as indicated above, other technologies available now can help speed its evolution and transfer. Applied research and development have however in recent years produced a few new aids to passive solar design. For example: new material applications. Such innovations can be incorporated in new designs however as they become available, whether from industrial R and D, or from government-sponsored R and D. No new materials are required to make a cost-effective contribution from passive solar energy possible. Cost-effective passive solar energy is possible now.

B. Demonstration

The National Solar Heating and Cooling of Buildings Program, managed by the U.S. Department of Energy, has been under way now for over five years. As part of this program, HUD administers the residential demonstration, residential market development, standards development, and information dissemination activities. In the demonstration portion of the program, HUD has funded solar systems of all types in over 12,000 dwelling units through more than 400 grants.[10] Passive solar energy grants in fiscal year 1979 consisted of 105 construction grants. These grants included 91 grants for 91 new single family units, and 14 grants for passive solar energy retrofits in multifamily buildings involving 233 units. Total U.S. funds committed were $1.5 million. There were no grants for passive solar energy in fiscal year 1980 and none are planned for fiscal year 1981.[11] The Department of Energy fiscal year 1981 budget for passive solar energy is $33.4 million—following presidential amendment and House action to August 14, 1980.

C. Commercialization

The passive solar market began with a small number of unorthodox designers and builders, many of whom were not concerned with the wide-scale marketability of their final products. Many

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[10] U.S. Department of HUD. Op. Cit. Foreword, "To The Reader," by Donna E. Shalala.

[11] Information on passive solar energy grants was obtained from HUD, Office of the Assistant Secretary for Policy Development and Research.

were building homes for themselves. By trial and error, they explored numerous ways to build homes of common and often indigenous materials which were heated directly by the sun. As these early prototypes proved very successful, additional builders who were searching for a low-cost and direct approach to solar home heating adopted passive design. To support this growing industry, reliable testing and simulation methods were developed by several engineering research centers, including the Los Alamos Scientific Laboratories in New Mexico. Their findings further documented the positive results of early prototypes.

With the groundwork now laid for an expanding passive homebuilding industry, the challenge now rests with individual homebuilders to adapt these trial designs in ways that are attractive to the market at large. While the additional costs, and the cost-effectiveness, of passive solar energy will vary with geography and architecture, the technology does not appear to require capital or labor of unique kinds. However, while the materials used and the construction skills of the homebuilding labor face need change very little, decisionmakers at all levels of the homebuilding industry will need to learn much more about passive solar energy. These decision makers include municipal councils and managers, financial institution executives, and building and housing inspection forces.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

As described above, no R. &. D. appears necessary as a prerequisite to the mass marketing of passive solar homes, so apparently there are no major technical obstacles to the demonstration and commercialization of the technology. Probably, innovations in materials available for passive design will continue to appear on the market from time to time. As a large market for homes of passive design appears, manufacturing firms may possibly be induced to commit new funds to research on materials specially adapted to this market. However there are no apparent "gaps," where materials of specified properties are required, but not yet developed, so passive solar applications should not be impeded by any intractable technical or materials problems.

B. Economic

The economic obstacles or advantages of passive home design and construction vary to some extent with geography; with climate; with local costs of insulation, multiple-pane glass, masonry, and other materials; and with labor in relation to local costs of conventional fuels. But the range of design possibilities, and the range of raw materials which can be converted to (for example) masonry walls, tends to ensure that some passive features will be feasible in almost every State. For example, climates which have snow cover on the ground throughout the heating season have an increased availability of solar heat through south-facing windows because the brilliant white ground cover can reflect sunlight upward toward

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interior ceilings, and this climatic feature can offset the increased heating needs of homes in cold climates.

C. Environmental and Social

Because the use of passive solar design generally reduces the need for conventional fuels, the environmental effects of this technology generally range from benign to beneficial. However, the effects of drastic reduction in air infiltration rates upon interior air pollution levels are still being studied.[12] Of course, a single home of visually dissonant features may sometimes be proposed or constructed in a community which finds it unattractive. But such occurrences are not unique to solar home design. On the other hand, communities which are designed around a solar visual "esthetic" can be perceived by their residents as subjectively attractive and socially unifying. Overall, the environmental and social obstacles to passive solar home design appear therefore to be slight.

D. Political

Political obstacles to passive home design however may be more difficult. Among these obstacles are the building codes which are established at the level of municipalities—by cities, counties, and towns acting as subsidiaries of individual States. In many instances building and housing codes written for a world of cheap fuel are obstacles to the best principles of passive solar design. For example, the health and safety objectives of such codes often lead to specifications for the number and placement of vents for kitchens and bathrooms, and for size and placement of windows. These same objectives often may be accomplished in good passive designs by means other than those required by the codes; however, inflexible code specifications of the means by which health and safety objectives shall be accomplished could impede passive solar projects until such codes are changed. The number of municipal legislative and regulatory councils which will have to be "sold" on the need for code amendments suggests that the political obstacles to passive solar home construction may be both grave and persistent.

One promising development regarding political obstacles is the Federal Government initiative to institute national Building Energy Performance Standards (BEPS) which would establish annual energy budgets for buildings of new design, based on the building's size, function, and the climate in which it is located. These standards have been under development since 1974. The idea was given legal substance in the 1976 Energy Conservation and Production Act, and the proposed standards were unveiled by the Department of Energy on November 19, 1979. Although such standards would not of themselves require passive design, they would establish ceilings on fuel consumption for buildings to be designed in the future. They would therefore push building designers and builders toward using passive features as one way to meet the fuel consumption standards. The American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) however opposes

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[12] U.S. Congress. Office of Technology Assessment. Residential Energy Conservation—Volume I. Washington, U.S. Government Printing Office, 1979, 355 p. See chapter X., Indoor Air Quality.

Building Energy Performance Standards.[13] While either the ASHRAE or the BEPS approach to building codes or standards would result in uniform regulations across the Nation, the conflict between the two approaches is a second example of a political obstacle.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Studies citied earlier and illustrated in Table 5 indicate that perhaps 4.5 quads per year could be saved through retrofits to make the existing housing stock "energy efficient." From 1980 through 1989 about 20 million or more new homes of all kinds may be built; (21.4 million were built from 1969 through 1978). If the new units are built to the standard of "energy efficiency," they will consume only 1.0 quads annually from 1990 onward. So, by achieving energy efficiency in the housing stock through retrofit of old units and construction of energy efficient new units, 100 million units could be heated in 1990 with fuel use 3.5 quads less than required for 80 million homes in 1978. It appears then that even though the number of homes may increse by about one-fourth in ten years, 3.5 quads of annual fuel consumption could be released from residential use for other purposes, even while this growth occurs. However, the 3.5 quads released do not come from passive solar energy. They come from achieving only energy efficiency in the housing stock. The saving which might arise from use of passive solar design is a saving which is over and above that from energy efficiency.

Could the 1978 housing stock be retrofitted to an average performance exceeding "energy efficiency?" We assume that some of the homes in that stock could be fitted with features which would provide limited heating of the sun-tempering and passive type. However we assume also that some others of the homes in that stock would not be capable of retrofit even to the lesser level of energy efficiency. So it seems imprudent to conclude that existing homes on average could reach beyond energy efficiency to sun-tempered or passive-solar perfomance. We therefore conclude for the sake of the following argument that any major contribution from passive solar energy as such can come only from homes yet to be built.

What is the maximum feasible proportion of the 20 million new homes to be built from 1980 through 1989 that could incorporate sun-tempering and passive solar design elements in addition to the basic element of energy efficiency? No one really knows the answer to this question. Since energy efficiency requires only furnace and thermal envelope efficiency—and these are ideas easily understood by most housing industry decision makers, including buyers—it seems likely that the obstacles to energy efficiency could be overcome in ten years. But sun-tempering and passive solar design are less easily understood by many housing decision makers. If all of the homes were constructed to passive design standards, the total

[13] "Battle Brews Over Best Conservation Approach," The Energy Daily, vol. 7, No. 227, November 29, 1979: 4; "Architects Protest BEPS Delay," Engineering News-Record, May 29, 1980: 10.

saving in 1990 over energy efficiency standards would be about 0.7 quads.[14] But such a construction achievement is impossible. It seems more reasonable to expect that by 1989 the entire new annual contribution to the housing stock could, on the average, meet the fuel consumption standard for a passive solar home. If full application by 1989 of passive design methods known now were approached in a linear way (a constant rate of approach in each of ten years) the annual energy saving in 1990 by the new homes, beyond the assumption of their energy efficiency, would be (as shown in the last column of table 6) about 0.4 quads.

TABLE 6.—HYPOTHETICAL ENERGY CONSUMPTION CONSEQUENCES OF CONVERSION TO PASSIVE SOLAR HOMEBUILDING, 1980–89

[Energy in quads]

Homebuilding year	New homes 1980–89 (cumulative) (millions)	Annual energy consumption by new homes (1990): If all new homes built are energy efficient	If all new homes built are passive solar	If energy efficient home-building is phased out	And passive solar home-building is phased in	The total energy consumption of all the new homes is	And the saving, compared to energy efficient homebuilding only, is
1980	2	.102	.028	.092	.003	.095	.007
1981	4	.205	.056	.174	.008	.182	.023
1982	6	.307	.083	.246	.017	.263	.044
1983	8	.410	.111	.308	.028	.336	.074
1984	10	.512	.139	.359	.042	.401	.111
1985	12	.615	.167	.400	.058	.458	.157
1986	14	.717	.195	.430	.078	.508	.209
1987	16	.820	.222	.451	.100	.551	.269
1988	18	.922	.250	.461	.125	.586	.336
1989	20	1.025	.278	.461	.153	.614	.411

B. Contribution by 2000 or Beyond

The ultimately feasible contribution to U.S. energy supply, of homes designed with all of the features of passive solar homes, is shown in Table 5, column 2, "Cumulative Annual Saving." This column indicates that the 80 million homes in the 1978 housing stock represent an energy resource which if exploited to fullest potential—might yield an annual fuel saving of 7.4 quads compared to the 8.6 quads used to heat those homes today. This potential fuel saving of more than 80 percent consists of 4.5 quads saved through energy efficiency measures, 0.7 quads through sun-tempering, and 2.2 quads through passive solar heating features. Achievement of this "ultimately feasible contribution" would require essentially complete replacement of the current housing stock. It seems unlikely that this could occur until very well into the 21st Century, although retrofit to achieve energy efficiency could be undertaken at any time, and some such activity is underway now.

If by 1989, as assumed in IV-A, the entire new annual contribution to the housing stock meets the fuel consumption standard for a passive solar home, and if another 20 million new homes were

[14] Energy efficient homes get 90 percent of their heat from fuel; passive solar homes get 25 percent of their heat from fuel. Passive solar homes therefore save (90–25)/90 of the 1.0 quads used by 20 million energy efficient homes.

built from 1990 to 1999 inclusive, these would add in the year 2000 an additional saving of about 0.7 quads each year to the 0.4 quads per year saved by the 20 million new homes assumed to be built from 1980 through 1989 (during the period in which passive home-building is assumed to be phased in). Thus, the total energy saving of the 40 million new homes assumed to be built between 1980 and 1999 would be about 1.1 quads in 2000, and in each year thereafter, compared to 40 million new energy efficient homes.

PHOTOVOLTAIC ENERGY CONVERSION *

SURVEY OF THE CURRENT SITUATION

A. Description of the Technology

1. THE PROCESS

Of the various solar technologies for converting sunlight into electricity, one of the most appealing is photovoltaic conversion via devices called solar cells. Solar cells convert sunlight directly into electricity. The process requires no moving parts, no prior conversion to heat, and need not be based on exotic or strategic materials. The basic scientific principles governing photovoltaics are well known and the technology for specialized uses is relatively advanced.

2. TERMS

The critical component in all photovoltaic systems is the "array" that collects and converts sunlight to electricity. The array is composed of a number of electrically interconnected sealed panels, each of which contains many individual solar cells. The remaining components making up a "photovoltaic system" are referred to as the "balance of system (BOS)" and include power conditioners, a storage element (batteries or a utility tie line), controls, and structural members, all of which are within the state-of-the-art.

3. MODE OF OPERATION

Receiving arrays of any size can be readily assembled by adding together any number of panels. Consequently, photovoltaics can offer considerable flexibility in applications and may be of value to a wide range of users.

Arrays are of two basic types: flat plate and concentrating. Flat plat arrays absorb sunlight as received. Concentrating arrays use lenses or reflectors to focus and concentrate solar radiation onto the cell area. Since the per unit area cost of the concentrator component is currently one-third lower than the unit area cost of typical solar cells, the cost of a photovoltaic panel might be reduced for some applications if expensive photovoltaic cell area is replaced by relatively inexpensive reflector or lens area.

4. MARKETS

Present and future markets for photovoltaic power systems have been identified in both off-grid and grid-connected applications. The current market is limited to off-grid applications with power requirements of a few hundred watts or less (for example, signal devices and communications relays). For this market, the photovoltaic device is usually sold as part of a complete "system" to operate independently of a utility grid.

*Prepared by J. Glen Moore, analyst in energy technology.

Near-term domestic markets will probably be limited to photovoltaic systems for such tasks as pumping irrigation water in remote areas, some area lighting, and special Department of Defense and other Federal applications. A photovoltaic market for utility grid-connected, privately owned residences could begin in the mid- to late-1980's if DOE achieves its 1986 price reduction goal of installed costs leading to electricity selling for 6 to 10 cents per kilwatt-hour in new U.S. residences. DOE is increasingly confident that the goal will be achieved and that new homes will be the first domestic photovoltaic market to displace significant amounts of energy from conventional sources.[1]

Developing countries which do not have well-established grid systems are expected to be an important near- and mid-term market for U.S. photovoltaic systems for a variety of remote power applications. Photovoltaics will compete in the off-grid market with batteries, thermal electric propane generators and small diesel or gasoline generators. DOE expects significant penetration of the market in developing countries following the achievement of its 1982 price reduction goals.[2]

The longer-term market for grid-connected photovoltaic power consists of two distinct segments: (*a*) distributed applications which are connected to a utility grid, and (*b*) electric generating facilities operated by utilities. Distributed applications include private residences, commercial and industrial establishments, and institutions such as schools and hospitals. It is generally assumed that distributed applications would operate with no on-site storage, using the utility grid for back-up.

For utility applications, photovoltaic systems could be installed on either central stations or on a distributed basis in neighborhood-size units. In either case, the utility would probably use the photovoltaics in a fuel-saver mode with little or no energy storage capability.

B. Known Resources and Reserves

1. DIURNAL CYCLE

Solar energy is essentially inexhaustible, but the cyclic nature of the resource can limit photovoltaic applications. The peak output of a solar cell occurs at noon on a clear day, with the sun's rays perpendicular to the array. At most times, then, the array output is less than its peak value and at night there is no output. One peak watt of solar cells delivers 4 to 5 watt-hours of electricity on an average day. Thus, to provide one continuous watt of output from a photovoltaic system requires the installation of about five peak watts of cells plus battery storage.

2. MATERIALS

The photovoltaics industry competes with the semi-conductor industry for supplies of solar-grade silicon. The current demand for this material has stretched worldwide production capacity to the

[1] Testimony of Dr. Bennet Miller, DOE Deputy Assistant Secretary for Solar Energy (Designate). 1981 DOE Authorization. Hearings before the Subcommittee on Energy Development and Applications of the House Committee on Science and Technology. Feb. 29, 1980.
[2] Ibid.

point where there is some concern that the near-term development of the photovoltaics industry may be affected.[3] But, this is a production problem rather than a materials problem. There are no anticipated long-term materials problems associated with solar cell arrays since the material of choice (at this time) is silicon—one of the most abundant and easily obtained elements in the earth's crust.

C. Current Contribution to U.S. Energy Supplies

Sales of photovoltaic power systems for terrestrial applications began in the mid-1970's. High costs limit the current market to off-grid applications. Nevertheless, the Department of Energy (DOE) estimates that, by the end of 1979, approximately 1.5 to 2 peak megawatts (cumulative) of photovoltaic arrays will be installed in the United States and nearly 3 megawatts will be installed worldwide (including U.S. installations). Assuming that 2 peak megawatts are installed in the United States, and that the average daily output of each peak watt is about 4 watt-hours of electricity, the total installed capacity of solar cells in the United States will generate 2.9×10^9 watt-hours of electricity per year. This level of output is negligible in comparison with 1979 total U.S. output of 2.3×10^{15} watt-hours. A powerplant consumes about 10 Btu's of energy to generate one watt-hour of electricity. Consequently, 29×10^9 Btu's are required at the powerplant to generate 2.9×10^9 watt-hours of electricity. With 5.8×10^6 Btu's available in each barrel of oil, in one year a powerplant would consume the energy equivalence of 5,000 barrels in order to generate the electricity produced by the current U.S. inventory of solår cells (assuming a maximum number of cells have been installed and that each is operating normally). Therefore, at best photovoltaics saved the energy equivalence of 5,000 barrels of oil in 1979.

D. State-of-the-Art

The photovoltaics industry is in its infancy. In fiscal year 1979 the total U.S. market for photovoltaic arrays was 2 megawatts (Mw).[4] Commercial applications are limited to small, remote, unmanned sites (microwave repeaters, corrosion protection, etc.).

Over 100 companies are now engaged in some aspect of photovoltaic research, development or sales.[5] The commitments of these companies range from production and sale of photovoltaic arrays to participation in Federally funded R. & D. Only 10 are engaged in the commercial production of single-crystal silicon solar arrays, two others have set up pilot production lines for cadmium sulfide (CdS) arrays and expect to be in commercial operations soon. One of the 10 silicon array manufacturing facilities has recently been automated with a production capability of approximately 2 Mw per year.[6]

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[3] Manufacturers look to government for assistance in developing market. Solar Engineering. October 1979: 26.

[4] Photovoltaic Energy Systems. Program Summary. DOE. January 1980, p. 6.

[5] Photovoltaic Procurement Strategy: An Assessment. Solar Energy Research Institute. Review Draft. June 1979.

[6] Op. cit.

Other candidate solar cell technologies are in various stages of R. & D. Prototype production facilities for polycrystalline silicon and thin-film cadmium sulfide are now being constructed. Other technologies such as thin-film amorphous silicon, polycrystalline gallium arsenide, and advanced concentrator materials will require substantial research progress before commercial production can be anticipated.

No large automated facilities exist for the fabrication of solar cells of any kind. Cells are currently fabricated in a highly labor-intensive batch process. In some sense, this technology is obsolete and it is unlikely that any additional production capacity of this type will be added.

At this time there are no integrated facilities dedicated to the manufacture of BOS equipment such as batteries, battery charge controllers, voltage regulators, or D.C. to A.C. converters. While such dedicated manufacturing facilities would reduce costs and improve the quality of equipment designed for photovoltaic applications, they do not now represent economically justified investments.

The cost of commercial silicon arrays and systems has declined steadily over the past several years, but is still prohibitively high for all but the low-power, remote applications market. In large orders, silicon arrays, which cost $25 to $30 per peak watt in 1976, are being sold for as low as $6 per peak watt today; [7] the installed cost of complete systems has decreased from $50 to $60 per peak watt in 1976 to $16 to $20 per peak watt in 1979.[8]

E. Current Research and Development

Since the mid-1970's, the basic strategy of the Federal Photovoltaic Program has been to reduce the costs of solar cells. To accomplish this, DOE, and previously ERDA, have been researching and developing various photovoltaic technologies. The principal avenue of research has been the Technology Development Subprogram, which is aimed at lowering the cost of photovoltaic devices by developing, among other things: (*a*) new ways of producing material used in solar cells, (*b*) new and cheaper processes for fabricating solar cells, and (*c*) new automated processes for connecting and mounting the cells on a backing material and then assembling individual cells into arrays. Other avenues include research in (*a*) advanced materials/cells, (*b*) high-risk R. & D., and (*c*) basic studies. The fiscal year 1980 budget request totals $160.6 million.

1. TECHNOLOGY DEVELOPMENT

This subprogram attempts to reduce the cost of manufacturing cells, arrays and other photovoltaic system components. The initial emphasis has been on the two principal array technologies, flat-plate arrays (single-crystal and polycrystal silicon), and concentrator subsystems employing several types of cell assemblies. In fiscal year 1980 DOE will undertake expanded efforts to reduce the cost of thin-film materials such as cadmium sulfide and amorphous silicon. Increased effort on BOS cost reduction is scheduled to be

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[7] Photovaltaic Energy Systems. Program Summary. DOE. January 1980.
[8] Testimony of Dr. Bennett Miller, op. cit.

the most important new thrust of fiscal year 1980. Nearly all of the budget growth in the Technology Development Subprogram will be in BOS cost reduction (see III, A.3).

The work on flat-plate silicon arrays is being carried out in the Low-Cost Solar Array (LSA) project. This project is addressing all steps in the array production process. The DOE has set specific goals for each of the following steps: (*a*) production of raw polycrystalline silicon of adequate purity; (*b*) creation of single-crystal wafers on sheet material; (*c*) encapsulation; (*d*) cell fabrication; and (*e*) high-volume automated array assembly.

In the case of concentrating systems, the technology development effort has two main thrusts. The first is directed toward developing designs, choosing materials and defining fabrication techniques which will lead to low costs for concentrating systems. The second is aimed at the development of solar cells capable of operating in concentrated sunlight at high efficiency.

2. ADVANCED MATERIALS/CELL RESEARCH

This subprogram moves promising cell technologies through the exploratory development phase. The objective is to make advanced cell options more viable as technical and cost competitive alternatives to flat-plate single-crystal silicon. Cadmium sulfide, gallium arsenide, amorphous silicon and polycrystalline silicon are the key materials being studied by DOE.

3. HIGH-RISK R. & D. RESEARCH

Efforts in this area are directed toward those materials and concepts which are perceived to have a high risk for achieving the goals of the Photovoltaic R. & D. Program, but which offer significant potential for substantial improvements in efficiency or cost reduction.

4. BASIC RESEARCH

This activity includes studies of basic mechanisms, tests and measurements, and the screening of materials in support of other Federal photovoltaic subprogram efforts.

F. International Activities

A number of industrialized countries, including the Soviet Union, Japan, France, and Germany, have been actively involved in the development of photovoltaic devices for terrestrial applications since the early 1970's.[9] These and other industrialized nations are competing today with the U.S. photovoltaics industry to establish photovoltaic markets in the developing nations. Five international markets for photovoltaic systems have already emerged. These are for consumer products, anticorrosion equipment, microwave repeaters, remote telemetry, and navigational and warning equipment. However, the major potential foreign markets are for water pumping and village power systems, and these have not yet been exploited.

[9] Solar Energy Activity Abroad. Electronics, May 22, 1972, p. 68.

Assessing the competitive environment for American photovoltaic manufacturers, a DOE study [10] indicated that (*a*) U.S. manufacturers are not aggressive exporters; (*b*) comparisons of research, development and institutional supports and incentives for United States, European and Japanese firms suggest that although the United States leads in technology today, it lags by a matter of years behind the Europeans in demonstrating and promoting photovoltaic applications in developing countries—there are 18 demonstration projects sponsored by European countries and only two by the United States; (*c*) export support and incentives from European and Japanese governments are demonstrably more effective than those of the United States; and (*d*) American photovoltaic firms have failed to develop a marketing infrastructure abroad, particularly in less-developed countries, a situation which places them at an initial disadvantage with their European and Japanese counterparts.

II. Prospects or Requirements for Further Development

A. Research and Development

A review of research opportunities and other aspects of photovoltaic energy conversion (primarily for central station applications) was conducted for DOE and the Office of Science and Technology policy (within the Executive Office) by a study group of the American Physical Society. A principal conclusion of the group was that a long-term and innovative Federal R. & D. program in photovoltaics is needed which must include:

(*a*) The search for and development of new photosensitive materials;

(*b*) Basic research on the interfacial phenomena that control photovoltaic conversion;

(*c*) Investigation of non-biological methods for direct production of fuels from sunlight; and

(*d*) Development of novel photovoltaic technologies or devices (for example, bubble concentrators, encapsulants for flat plate cells, and noncell related structural materials) to aid in identifying the critical materials problems limiting performance and cost.[11]

In addition, the group identified research opportunities in several specific areas:

1. SILICON TECHNOLOGY

Silicon-based photvoltaics is the reference technology for both flat plate and concentrator systems. The performance of these cells currently falls below theoretical limits for reasons that are not adequately understood. Innovations in cell design and processing technology might lead to improved efficiency and lower costs.

2. CONCENTRATORS AND HIGH EFFICIENCY CELLS

A promising approach to competitive photovoltaic power in the near-term is the use of concentrators and high efficiency cells. Recent concentrator designs suggest a possibility of substantial reductions in structual costs, particularly at high concentrations, and there are a number of possible ways of making cells with

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[10] Export Potential for Photovoltaic Systems. Prepared for DOE by the Pacific Northwest Laboratories. DOE/CS-0078, April 1979.

[11] Principal Conclusions of the American Physical Society Study Group on Solar Photovoltaic Conversion. January 1979.

efficiencies of 25 percent or more. Such cells, although too expensive for flat plate systems, might be suitable for concentrator systems.

3. THIN FILMS

Thin film solar cells could form the basis of an inexpensive photovoltaic technology. (In the photovoltaic filed the term "thin film cells" refers to cells in which the active layers have been deposited or formed on an appropriate substrate, as opposed to crystalline cells which are usually manufactured by slicing thin wafers from a crystal ingot.) Work to develop this potential for low-cost power generation will include the search for new materials and research to explore basic phenomena in thin films.

B. Demonstration

1. RESIDENTIAL APPLICATIONS

Following a survey of selected aspects of DOE's photovoltaic program, the General Accounting Office (GAO) identified a need to initiate a limited number of well-controlled experiments in residential photovoltaic applications.[12] The GAO noted that several studies performed for DOE have stated that the residential sector should be an important early market in which photovoltaic energy systems can become competitive as an energy source—assuming DOE's cost reduction goals are met. Since residential applications of photovoltaic energy systems are not being funded, there is virtually no data available regarding the operation of such systems. Because residential uses of photovoltaic energy systems might be an important early market, GAO concluded that it is important to have operating data on how well systems work in that setting. A limited number of controlled experiments undertaken now would make data available by the mid-1980's when such systems are expected to become competitive with other energy sources. The GAO called for a redirection of funds in the proposed 1980 budget to initiate these experiments.

The DOE commenced operation of a photovoltaic Residential Experiment station in Boston in fiscal year 1980 and has begun to take bids for a Southwest Residential Experiment station. These two stations should facilitate deployment of photovoltaic systems for residences when the economies of such systems becomes favorable.[13]

2. NEED FOR DEMONSTRATIONS AT THIS TIME

With respect to photovoltaic demonstrations (presumably for central station applications), the American Physical Society study group concluded that deployment at this time should be limited to the scale necessary to generate field engineering and systems knowledge. It was the group's opinion that until a clear pathway to the photovoltaic future has been established, efforts to stimulate a large scale, low cost industry through hardware procurement/demonstration are premature.

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[12] General Accounting Office. Memorandum to the Secretary of Energy, James Schlesinger. Publication B-178205. Apr. 19, 1979.

[13] Testimony of Dr. Bennett Miller, op. cit.

3. FEDERAL BUILDINGS

In fiscal year 1978 authorizations (Public Law 95-238) and appropriations (Public Law 95-240), and in the National Energy Conservation Act (Public Law 95-619), which is part of the National Energy Act, Congress mandated the procurement of photovoltaic systems for use in Federal buildings as a means of encouraging the mass production of solar cells. The Administration has differed with Congress over the advisability of this approach to commercialization. Instead of proceeding with procurements, DOE has delayed a major buy to allow time for a procurement to be designed and to allow further developments in photovoltaic technology. In testimony before the House Subcommittee on Energy Development and Applications, DOE stated that technological breakthroughs, rather than procurements, were the key to a major photovoltaics impact.[14]

C. Commercialization

1. SYSTEMS MARKET

Currently, the photovoltaic industry is commercial. However, because of the availability of low-cost electricity and a well-defined grid system in this country, the industry is geared for the systems (off-grid) market rather than the bulk power (grid-connected) market. For the industry, the primary difference in the two markets is that in the systems market the array cost is not critical (since the array is only one of several components representing from 30 to 60 percent of the system cost), while in the bulk power market the array cost would be the dominant factor. Consequently, the industry is currently more concerned with reducing the cost of the system than it is with the array cost. The systems market has a limited potential for impacting the U.S. energy mix; to have a major impact photovoltaics must be competitive with grid power.

2. BULK POWER MARKET

The industry must emphasize array cost reductions if photovoltaics is to achieve commercial competitiveness in the bulk power market. This will require a redirection in the present industry effort, and will entail major investments in equipment and processes which can lead to low-cost, large-scale production. To support and encourage a shift to the bulk power market, the industry has called for Federal economic incentives. Industry has further indicated the need for a long-range national commitment to photovoltaics so that it will feel secure in making the necessary investment in facilities to mass produce solar cells.

3. FEDERAL PROGRAM

The Federal Photovoltaic Program includes a commercialization component which is intended to accelerate the introduction and diffusion of a cost competitive photovoltaic industry. The Federal photovoltaic commercialization plan calls for targeted Federal pur-

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[14] Testimony of Dr. Bennett Miller, DOE solar program director. 1980 DOE Authorization. Hearings before the Subcommittee on Energy Development and Applications of the House Committee on Science and Technology. Vol. 5. Feb. 26, 1979.

chases and cost-shared private purchases of complete systems to be used to: (*a*) conduct systems engineering and market tests, (*b*) help attain requisite economies of scale, (*c*) promote installer and maintenance training, and (*d*) stimulate and develop market demand.

4. FEDERAL COST-SHARING

To help accelerate commercialization, DOE is considering the advisability and usefulness of up-front Federal cost sharing with industry for early silicon material and photovoltaic collector production facilities. Although DOE has reached no definitive conclusion on this, a recent report suggests that such an approach may be desirable, provided proprietary interests of industrial participants can be protected.[15] The rapidity with which photovoltaic technology is advancing has placed the industry in a difficult position which could be ameliorated by Federal cost sharing. Technical progress is being made so quickly that by the time a firm has invested in a new production line, research may well have found a superior technology which would render the "new" process obsolete. Federal cost sharing may be able to encourage the industry to make the investments needed to keep pace with technological advancements.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

1. LACK OF AVAILABLE SYSTEMS AND SYSTEMS EXPERIENCE

Very few systems for intermediate market applications are now available "off-the-shelf." In general, each photovoltaic system is custom designed for a specific end use application. Furthermore, to be competitive in the systems market, manufacturers are frequently required to have expertise in the end-use markets where photovoltaics are employed (for example, irrigation systems, communications, and cathodic protection). Developing this expertise can be a timely, costly and limiting requirement.

2. LIMITED AVAILABILITY OF SOLAR-GRADE SILICON

Inadequate supplies of solar-grade silicon could be a near-term problem for the industry if markets expand and production continues to increase at current rates. Already, a worldwide shortage of refining capacity for polysilicon materials has placed the solar industry in competition with the semiconductor industry for these supplies. A recent study highlighted the possibility of a severe shortage of refined polysilicon material in the early 1980s, especially if a very aggressive photovoltaic commercialization program is pursued.[16] Current suppliers are unwilling to install additional conventional refinement capacity, because the recent appearance of new refinement technologies is likely to reduce current prices by a

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[15] Photovoltaic Procurement Strategies: An Assessment. Solar Energy Research Institute. June 1979.

[16] Silicon Materials Outlook for 1980-85. Prepared for DOE by the Jet Propulsion Laboratory. JPL Document 5230-1. October 1979.

factor of six, making conventional silicon refinement processes obsolete. The possibility of a shortage of refined material just when the commercialization program is accelerating may warrant a thorough evaluation of options to alleviate such a problem.

3. BALANCE OF SYSTEM

A GAO survey of selected aspects of DOE's photovoltaic program concluded that DOE has underemphasized the balance of system (non-array) components of photovoltaic systems.[17] The GAO found non-array costs account for more than half of the total photovoltaic systems cost. It further found that DOE's cost reduction goals and corresponding strategies are primarily directed at reducing the cost of the array itself and not the non-array cost. Achieving cost reduction for non-array components may be particularly difficult because components, such as batteries and electrical equipment, are manufactured by mature industries which in many cases are already substantially automated. Other non-array costs, such as those relating to the installation of the device, are labor intensive with little hope for cost reductions. In GAO's view, the difficulty in achieving the necessary cost reductions emphasizes the need to develop cost goals for non-array components and to implement the necessary strategies to reach those goals. The DOE solar program officials have recognized this problem and have taken steps to correct it in the fiscal year 1980 budget. The efforts planned for 1980, however, only represent a first step in developing an overall strategy for reducing nonarray component costs. The GAO recommended that solar photovoltaic program officials be required to pursue specific research projects with precise cost reduction goals for nonarray components.

B. Economic

The limits to photovoltaic system deployment and use, both in the near- and long-term, are primarily economic. The current annual market is on the order of 2 Mw per year.[18] Photovoltaic systems manufactured in the United States are largely sold in the international market at a price of $10–$25 per peak watt.[19] The DOE has formulated a cost reduction plan for photovoltaics which, if successfully pursued, would lead to systems competitive with utility-generated power by about 1990.[20] According to the plan, systems costs should be in the $6–$13 per peak watt range in the 1982–84 time frame (expressed in 1980 dollars). At those prices, the market for photovoltaics will still be dominated by foreign applications (primarily for village power and water pumping). Applications in the United States in the midterm would not be economically justified, except for military and other Federal remote applications markets. The cost of electricity generated by systems in this cost range would be 20 to 50 cents per kw hour.

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[17] General Accounting Office. Memorandum to the Secretary of Energy, James Schlesinger. Publication B–178205. Apr. 19, 1979.

[18] Photovoltaic Energy Systems. Program Summary. DOE January 1980.

[19] Federal Policies to Promote the Widespread Utilization of Photovoltaic Systems. Vol. II: Technical document. Prepared for DOE by the Jet Propulsion Laboratory. Preliminary Draft. November 1979.

[20] Multi-Year Program Plan, National Photovoltaic Program. DOE. June 6, 1979.

By 1986, according to the plan, photovoltaic systems should be available in the $1.60–$2.60 per peak watt range, with electricity costing 6 to 12 cents per kw hour. Cost reductions on this order would be acheived through a major expansion of production capacity using advanced automated facilities and concentrator technologies. With costs at this level, both foreign and domestic markets are expected to grow rapidly. For domestic applications, the plan anticipates that the single-family, new home construction market will grow at the fastest rate, to be followed by additional residential, commercial, selected industrial, and, possibly, central station applications.

The final phase of DOE's cost reduction effort should occur in the early 1990–2000 time frame with photovoltaic systems generally competitive with foreign and domestic utility-generated power. Systems are expected to cost $1.10 to $1.30 per peak watt (expressed in 1980 dollars) and generate electricity at 4 to 9 cents per kw hour.[21] At this point DOE planners project an industry composed of a healthy mix of photovoltaic technologies with a combined annual production capacity at nearly 1,000 megawatts or greater.

C. Environmental

An attractive feature of the photovoltaic technologies is the relative absence of any release of pollutants at the use site.[22] The only significant pollutant is the heat released from the collectors to the atmosphere. However, the collector and storage subsystems can present some health and safety problems in the event of accidents or overheating conditions. Mining and cell manufacturing may present more severe environmental problems. The potential exists for a variety of chemical and thermal releases, dependent upon the type of cell manufactured and the effectiveness of environmental control technology. The disposal or recycle of defective, broken, and obsolete cells may also cause environmental impacts which must be addressed.

D. Social

See: Solar Heating and Cooling of Buildings, III. D.

E. Political

See: Solar Heating and Cooling of Buildings, III. E.

F. Utility Interface

Utility grids can provide an inexpensive source of backup power for photovoltaic systems, thus offering an attractive alternative to electric storage. The setting of electricity rates for buying and selling power to utilities is critical to the competitiveness and deployment of distributed, non-utility owned photovoltaic systems. The relevant institutions (utilities, municipalities and public utility commissions) may resist distributed photovoltaic interconnections

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[21] Testimony of Dr. Bennett Miller, Deputy Assistant Secretary for Solar Energy (Designate). Hearing before the Subcommittee on Energy Development and Applications of the House Committee on Science and Technology, Feb. 29, 1980; table 9.

[22] Environmental Development Plan [for] Photovoltaics. DOE. DOE/EDP-0031. September 1979.

through punitive rates or other measures. In those instances where utilities resist relinquishing their exclusive franchise to produce and sell electrical power, appropriate Federal action under the Public Utilities Regulatory Policies Act of 1978, or other public law, may be required.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Photovoltaic power is not expected to make a significant contribution to U.S. energy supplies until it is competitive with utility-generated power. According to DOE's cost reduction program plan, photovoltaics should be marginally competitive with utility power in about 1990. Until that time, domestic markets will be limited to off-grid applications, primarily for remote DOD and other Federal agency requirements. Because of limited markets available for photovoltaic systems in the near- and mid-term, the contribution of photovoltaic power to U.S. energy supplies in 1990 is expected to be on the order of 0.1 quad.[23]

B. Contribution by 2000 or Beyond

The success of the DOE cost reduction program is critically important to the widespread use of photovoltaic systems in 1990 and beyond. Success will depend upon major scientific and/or technological advances in both cell and balance of system technologies. If the program stays on schedule and photovoltaic power becomes competitive with grid power by 1990, a rapid deployent of photovoltaic systems is expected to follow. Assuming photovoltaics also remain competitive with other alternate energy sources under development by DOE (oil shale, wind, etc.), one DOE source estimates the energy savings from photovoltaics could be 0.8 quads by the year 2000.[24] If the program is not fully successfully in meeting its cost reduction goals, widespread use in the United States would be delayed until such time as photovoltaic power becomes competitive with grid power.

[23] Department of Energy Solar Energy Objectives Calendar Year 1980. DOE/CS-0155. April 1980, p. 14.

[24] Department of Energy Solar Energy Objectives Calendar Year 1980. DOE/CS-0155. April 1980, p. 14.

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SATELLITE POWER STATIONS *

I. Survey of the Current Situation

A. Description of the Technology

One problem with using solar energy on Earth is that it is impeded from falling freely onto the planet's surface by inclement weather, the diurnal cycle, and the screening effects of the atmosphere (on a clear day, the amount of sunlight reaching the ground is about 65 percent of that above the atmosphere). These restrictions have spawned the concept of building devices for using the greater concentration of solar energy above the atmosphere for operating power plants which generate electricity. The electricity would then be converted into microwaves, beamed to receiving and rectifying antennas (called rectennas) on the surface of the planet, and reconverted into electricity (there also has been some discussion of using lasers instead of microwaves for power transmission). This concept is referred to as a satellite power station or solar power satellite (SPS).

In January 1979, the Department of Energy (DOE) and the National Aeronautics and Space Administration (NASA), which are jointly studying SPS, published a reference system report on SPS selecting a photovoltaic-type SPS for further study.[1] Other types of SPS (solar thermal, nuclear, thermionic diode, mirrors) had been suggested and may eventually prove preferable to the photovoltaic design, but for the purpose of determining the feasibility of SPS, DOE and NASA selected photovoltaics.

The photovoltaic concept, first proposed in 1968, calls for constructing arrays of solar cells in space for the direct conversion of sunlight into electricity.[2] Each SPS would consist of two arrays, each approximately 5 by 10 kilometers for a facility producing 5 gigawatts (5,000 megawatts) of power on the ground, and separated by a microwave (or laser) transmitter. Larger facilities, producing 10 gigawatts, could also be constructed. The SPS would be placed in geosynchronous orbit around the Earth, where an object will maintain a fixed position relative to any point on Earth (at an altitude of 35,800 kilometers above the equator). A reaction control system would be required to maintain the SPS in that orbit. The SPS would be eclipsed by Earth's shadow for varying lengths of time each day, but never for longer than 72 minutes at a time, and totalling about 1 percent of the year. Coupled with expected down time for routine maintenance, different studies estimate a plant factor between 80 and 92 percent.

The solar cells could be made of either silicon or gallium-aluminum-arsenide (GaAlAs). Silicon solar cells are the type used today,

* Prepared by Marcia S. Smith, specialist in aerospace and energy technology.

[1] U.S. Department of Energy and National Aeronautics and Space Administration. Satellite Power System: Reference System Report. Washington, National Technical Information Service, 1978 (published January 1979). DOE/ER-0023.

[2] Dr. Peter Glaser of Arthur D. Little, Inc. originated the SPS concept.

and some experts expect that silicon cells with an efficiency of 18 percent will be available by the time an SPS would be constructed (compared with 11–15 percent efficiency now achievable). GaAlAs cells are expected to have a higher efficiency, perhaps as high as 27 percent. Mirrors would be used to concentrate the sunlight onto the solar cells in the GaAlAs system, although they are not necessary in the silicon design. The DOE–NASA reference design did not choose between silicon or GaAlAs cells since each has advantages and disadvantages, and the agencies felt no choice could be made at this time. For the purpose of that study, an efficiency of 16.5 percent was assumed for silicon cells and 18.2 percent for GaAlAs. Overall efficiency for SPS, from sunlight in orbit to electricity on the ground, is estimated to be 7.06 percent for a silicon cell system and 6.97 percent for a GaAlAs cell system.

Each SPS could either be constructed in low Earth orbit (LEO) and then transferred to geosynchronous Earth orbit (GEO), or be constructed in GEO initially. The DOE–NASA reference design calls for construction in GEO. All materials for the SPS would have to be taken from the Earth's surface into space for construction, requiring a large number of space launches for both equipment and personnel. As many as four separate space vehicles might be required: a heavy lift launch vehicle (HLLV) for transporting construction material from the Earth to LEO and a cargo orbital transfer vehicle (COTV) for taking the material up to GEO; a personnel launch vehicle (PLV) for carrying crews from Earth to LEO and a personnel orbital transfer vehicle (POTV) for taking the crews to GEO. The DOE–NASA reference design estimates that for two 5 gigawatt SPS's built per year, a silicon cell design would require 375 HLLV flights, 30 PLV flights, 30 COTV flights, and 12 POTV flights; while a GaAlAs cell system would require 225 HLLV flights, 38 PLV flights, 22 COTV flights, and 17 POTV flights.

The suggestion has also been made that construction material for SPS's could be mined from the Moon or asteroids, and refined at a space station located either in Earth orbit or at one of the gravitation equilibrium points in the Earth-Moon system (called libration points or Lagrange coordinates). This approach would reduce the drain on the Earth's natural resources and might reduce SPS costs by eliminating the expensive launchings from Earth to orbit, although if the costs for the space station and equipment to retrieve asteroids or lunar material are factored in, the total cost for SPS would very likely increase substantially in this scenario.

B. Known Resources and Reserves

Solar energy is essentially inexhaustible.

C. Current Contribution to U.S. Energy Supplies

None.

D. State-of-the-Art

The SPS concept is only now undergoing feasibility determination studies. Silicon photovoltaic cells have been used to power spacecraft for many years, but no arrays the size of those envisioned for SPS have been utilized. The United States has no experience in building large space structures in either low or geosynchronous Earth orbit, nor have orbital transfer vehicles (for personnel or for construction materials) or a heavy lift launch vehicle (for Earth to space transportation of construction material) been developed. The only element of the space transportation segment of SPS that is expected to be available soon is a vehicle for carrying crews from Earth to low Earth orbit—the space shuttle, which is expected to become operational in 1982, although it has not flown in space yet.

E. Current Research and Development

The DOE is the lead agency for SPS studies. The DOE program is broken down into four areas: environmental aspects, social aspects, comparative economics with other electricity sources, and technology. The DOE is responsible for the first three, while NASA is responsible for the fourth.

Through the end of fiscal year 1979, the Federal Government had expended $14.2 million for SPS studies, with $5.5 million appropriated for fiscal year 1980. The goal of the current effort is to determine whether or not SPS is a viable concept and worthy of constructing a prototype.

Although Japan and the European Space Agency have indicated interest in participating in a cooperative SPS development program with the United States, neither they nor any other foreign government is now conducting an SPS program.

II. Prospects or Requirements for Further Development

The earliest estimate by SPS supporters for having SPS on-line is 1995, assuming that all needed funding is provided, while DOE uses the year 2000 for its reference design. Current estimates suggest that initial costs for the first SPS will be on the order of $100 billion, with additional 5 gigawatt SPS's costing $11.5 billion. The SPS concept is still in the feasibility determination phase, and estimates of required capital, time, and manpower cannot be made with any certainty. The 1979 NASA/DOE reference design does not address the question of how much an SPS program might cost.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

In the 1979 DOE/NASA reference design report on SPS, areas in which critical technology advancements are needed were identified as follows: microwave power transmission, solar arrays, power distribution, structures and control, materials, construction, and space transportation. The DOE concluded in 1980 that "SPS requires no scientific breakthroughs" but "is recognized as a difficult engineering development project requiring substantial advancements in technology in many areas." [3]

[3] U.S. Department of Energy. Office of Energy Research. Satellite Power Systems (SPS) Concept Development and Evaluation Program: Preliminary Assessment. Washington, National Technical Information Service, September 1979. DOE/ER 0041, p. 5.

B. Economic

For systems in the early stage of research and development, such as SPS, potential economic competitiveness with other electricity sources is impossible to determine. Costs for construction of the first SPS and subsequent SPS's, maintenance of each SPS and associated rectennas, and the date for introduction of the commercial SPS's are all unknown. The DOE-NASA reference design assumes construction of two 5,000 megawatt SPS's per year for 30 years beginning in the year 2000, for a total of 300 gigawatts of electricity by 2030. Assuming the most pessimistic plant factor estimate (80 percent), the actual electricity available would be 240 GW. Since the viability of the SPS concept has not been proven yet, such a scenario is speculative at best, and DOE emphasizes that this time frame was chosen only to provide a baseline from which to proceed with the study, and does not necessarily represent that agency's preferred scenario.

Costs for the first SPS have been estimated at $100 billion, with each subsequent SPS costing $11.5 billion.

C. Environmental

The environmental effects of SPS are not known at this time, although there are several potential areas of difficulty in this regard. The problem which receives the most attention concerns potential effects on the atmosphere and on biota from the microwaves that would be used to transmit electricity from orbit to Earth. At the present time, there are no internationally accepted standards for microwave radiation exposure, with the U.S. standard 1,000 times higher than that of the Soviet Union. Current plans call for the most intense area of the SPS microwave beam to be 23 milliwatts per square centimeter, and SPS advocates assert that the level of microwave radiation at the periphery of the rectenna would satisfy the strictest microwave radiation exposure limits (those of the Soviet Union).

It should be noted that the microwaves involved in SPS power transmission are a type of non-ionizing radiation, unlike the type of radiation emitted in nuclear reactions. Low-level non-ionizing radiation exists in our environment at the present time from sources such as the transmission of television and radio signals. The health effects of long-term exposure to low-level non-ionizing radiation are largely unknown at the present time, with studies only now getting underway in the United States. Studies in the Soviet Union have shown that the major effects concern behavior, with long-term exposure causing jittery nerves and general anxiety. These results have not been confirmed, however. Non-ionizing radiation is not known to cause cancer or genetic defects, but rather causes heating, just as a microwave oven heats food. Long-term exposure to high levels of microwave radiation could "cook" a person or animal, but this level is about 1,000 milliwatts per square centimeter, considerably higher than the 23 milliwatts per square centimeter planned for the center of the SPS beam; exposure to 100 milliwatts per square centimeter has been shown to cause cataracts in test animals.

Effects on the atmosphere would include heating of the ionosphere by the microwave beam. The major problem in this regard is considered to be potential interference with radio transmissions. The ionosphere reflects certain wavelengths back to Earth while other wavelengths pass through. If certain areas of the ionosphere are heated by microwave beams, it is possible that radio signals which normally pass through the ionosphere will be reflected back to Earth, causing interference problems. There may also be radio frequency interference with orbiting satellites, and terrestrial communications in the area of the Earth-based rectenna.

Some of these problems might be overcome by using lasers instead of microwaves for power transmission, although no exhaustive study of the laser concept has been prepared. Lasers may encounter stiff opposition from the general public since they are so often viewed as having lethal effects. (See III. D, below).

Resource utilization for constructing SPS's is another area of potential concern. Assuming that SPS construction material would come from the Earth, the January 1979 DOE-NASA reference design concluded that there are potential shortfalls in four elements for constructing a large number of SPS's: gallium (if gallium aluminum arsenide cells are used), mercury, tungsten, and silver.

Subsequent to this first analysis, DOE released a preliminary materials assessment for SPS which identifies 20 materials for which there might be a supply problem, of which 5 were considered to be potentially serious: gallium, graphite fiber, sapphire, solar grade silicon, and gallium arsenide. The assessment found that in general, the gallium option presented more severe materials problems than the silicon option, although the report noted that this difference might be because the technology for silicon is more advanced.[4]

Another area of concern is land usage for siting the rectennas. At sharp angles, atmospheric heating from the microwave beam might follow Earth's magnetic lines, increasing the area of the ionosphere heated by the microwave radiation. Consequently, scientists have suggested (although no definitive conclusion has been reached) that the lowest latitude at which an SPS rectenna could be placed is 29 degrees north (or south) latitude. As the latitude increases, the rectenna must become more and more elliptical to compensate for the "flashlight effect," [5] hence the effective limit for rectennas is approximately 40 degrees north (or south) latitude. These limits roughly correspond to placing rectennas from Brownsville, Texas to Indianapolis, Indiana, in the northern hemisphere.

Although longitude locations depend on placement of the SPS at a certain point in geosynchronous orbit, there are many other nontechnical factors which will decide where rectennas can be placed, including topography, population, and radio frequency interference. Under contract to DOE, Rice University prepared a study of poten-

[4] U.S. Department of Energy. Office of Energy Research. Preliminary Materials Assessment for the Satellite Power System (SPS). Washington, National Technical Information Service, January 1980. DOE/ER-0038, pp. i-iv.

[5] "Flashlight effect" refers to the fact that as the angle increases between the source of electromagnetic waves (light in the case of a flashlight, microwaves in the case of SPS) and their final destination, the beam widens into an increasingly elliptical shape. If the SPS rectenna were placed on the equator directly below the SPS, its shape would be circular. As latitude increases, the microwave beam becomes more elliptical and the rectenna dimensions must be adjusted accordingly so as to capture all the microwave radiation being transmitted.

tial rectenna locations based on 36 variables, and developed 11 maps proceeding from less restrictive to more restrictive variables.[6] These maps show that few locations other than the central portion of the United States could serve as rectenna sites, thereby requiring retransmission of the energy through the utility grid to reach high energy consumptive markets and increasing the cost of the electricity. Siting the rectennas off-shore might alleviate the land usage problem, although transmission of the electricity to land could be expensive.

D. Social

Fear of exposure to microwave radiation, or to laser beams if that option is chosen, may well prove the largest stumbling block to SPS. Like nuclear energy, emotions are likely to run high on the issue of exposing the general population to such potential dangers, even though advocates of the microwave and laser systems offer assurances that fail-safe systems can be engineered to prevent such occurances. Also in this vein is the potential of the SPS as a military weapon, "frying" cities with doses of microwaves or "zapping" people with lasers. Since a pilot signal emanating from the rectenna is required to keep the more than 7,000 subarrays in the microwave or laser transmitter properly aligned for transmission of the energy, intentional or unintentional redirection of the beam could be avoided, for without the pilot signal the energy would dissipate into space rather than following its guided course to the rectenna. In addition, a system might be engineered such that if the pilot signal deviated more than a few degrees, the SPS would automatically cease operation.

Another concern about the potential military implications of SPS is that once a country has the capability to build SPS's, it would de facto have the capability to pursue purely military missions using the hardware developed for SPS (especially the launch vehicles which could be used to place weapons systems or antisatellites in orbit).

A corollary question involves the potential vulnerability of SPS to military attack. J. Peter Vajk of Science Applications, Inc. has concluded that a 1–3 megaton nuclear device exploded within 1,000 kilometers of the arc where the 60 SPS's would be located would destroy all the satellites because the resulting radiation would create power surges and burn out the SPS systems. If the yield of the device was increased to 50–60 megatons, it could be exploded in low Earth orbit and destroy all 60 SPS's, although every other satellite in the vicinity would also be destroyed. Nevertheless, Vajk concluded that SPS was no more vulnerable to military attack than our present terrestrial power systems, which he claimed could be destroyed in the same manner by the explosion of 4 to 10 well-placed 10–20 megaton nuclear devices 100 kilometers above ground. He recommended that institutional and technological safeguards be included in the SPS design to alleviate potential vulnerability to the greatest extent possible, including international inspections,

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[6] Blackburn, James B., Jr. and Bill A. Bavinger. Satellite Power System (SPS) Mapping of Exclusion Areas for Rectenna Sites. Prepared under contract to the U.S. Department of Energy. Washington, National Technical Information Service, October 1978 [published January 1979]. HCP/R-4024-10.

international agreements, self-defense systems for the SPS, and comprehensive space surveillance.[7]

The more general issues of centralized versus decentralized energy also applies to SPS. Without question, SPS is a centralized, high technology energy source. Some supporters of ground-based solar energy schemes claim that SPS supporters are trying to "steal the Sun from the people," turning their decentralized energy technology into a centralized one. They are concerned that money which otherwise would be given to development and commercialization of ground based solar options will be used for SPS.

E. Political

SPS has already begun encountering political opposition. In debate in the second session of the 95th Congress on H.R. 12505, which would have increased funding for SPS to $25 million for fiscal year 1979 for technology verification studies, it was charged that SPS is an attempt by a failing aerospace industry to bolster its future:

> This program is a creature of the space industry conceived to keep its nose in the Federal trough forever. Since we have been slowing down the space program, the industry has been looking for avenues to continue its activities at Federal and taxpayer's expense. They have rested on the popularity of solar energy to promote this project, and it is a project that is just absolutely mind-boggling.[8]

Although the bill passed the House in 1978 (267–96), the Senate did not report any SPS bill from the Senate Energy and Natural Resources Committee, despite the fact that two such bills (S. 2860 and S. 3541) had been introduced.

Legislation very similar to H.R. 12505 was introduced in the House in the 96th Congress (H.R. 2335) and was passed on November 16, 1979 by a vote of 201 to 146. As in the previous year's debate, opponents of the legislation stated that SPS was a creature of the space industry. In addition, they saw the bill as a premature commitment to SPS development, noting that they had been unsuccessful in deleting development aspects of the bill during its consideration in the House Science and Technology Committee (the bill's title is Solar Power Satellite Research, Development and Evaluation Program Act). A third line of opposition focused on the fact that DOE and NASA are currently conducting a three-year study of the feasibility of SPS, the results of which are due in mid-1980. Opponents felt that Congress should wait until it hears the results of that study before committing another $25 million to the program, and remarked that Congress had already indicated its support of determining the feasibility of SPS by funding the three-year study. Therefore, they argued, disapproval of H.R. 2335 did not necessarily indicate congressional abandonment of the SPS concept.

Proponents of H.R. 2335 countered the above criticisms by noting that the bill did not in any way call for actual hardware construction for an SPS, but only for technology verification work related to needed advancements (as already discussed in section III. A,

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[7] Vajk, J. Peter. Paper presented at the Department of Energy Satellite Power System (SPS) Program Review, Lincoln, Nebraska, Apr. 22–25, 1980.

[8] Ottinger, Richard. Debate on H.R. 12505. Congressional Record [daily ed.], June 22, 1978: H5964.

above). They also explained that the $25 million in H.R. 2335 would in no way duplicate on-going work within DOE or NASA. Responding to the point that SPS was simply a bonanza for the failing aerospace industry, SPS proponents stated that previous space programs have given the United States experience in space, and now is the time to begin reaping the benefits of our space expertise by putting space to work for us.

No separate SPS legislation has been introduced in the Senate for the 96th Congress, although H.R. 2335 has been referred to that body for consideration. The Senate has appeared content to consider SPS as part of the overall DOE budget, rather than providing specific legislation for it as it has done in other areas such as synthetic fuels.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

None.

B. Contribution by 2000 or Beyond

The current DOE reference design for SPS calls for constructing two 5,000 megawatt SPS's per year for thirty years, beginning in 2000, although the Agency has emphasized that the timetable was developed only to provide a reference point and is not necessarily the Government's preferred scenario. If this scenario were to become reality, SPS's theoretically would be providing 300 gigawatts of electricity by 2030. Assuming the most pessimistic estimate of plant factor made to date, 80 percent, actual electricity generation would be 240 gigawatts.

SOLAR HEATING AND COOLING FOR BUILDINGS *

I. Survey of the Current Situation

A. Description of the Technology

The Federal solar heating and cooling program involves a broad range of solar collector systems and building design techniques which provide hot water and space heating and cooling for residential and commercial buildings. The numerous systems that have been devised to collect and store solar energy for these purposes are generally described as either "active," "passive," or "hybrid."

Active systems typically employ flat plate collectors, a circulating heat transfer fluid (which can be either water or air), thermal energy storage, and distribution and control subsystems. Flat plate collectors heat air or water to temperatures between 120 degrees and 200 degrees F, although some systems operate at lower temperatures. Where higher temperatures are needed to operate absorption type air conditioners for cooling, a variety of dish, parabolic trough, or evacuated tube collectors can be deployed which achieve temperatures of 300 degrees F and higher by concentrating the Sun's energy. Active systems use electrical or mechanical energy to circulate the heat transfer fluids. This distinguishes them from passive systems which utilize natural-energy flows (convection and conduction) to transfer energy. Passive systems can provide both space heating and cooling by using the building itself, along with innovations such as greenhouses, roof ponds, and massive thermal storage walls, to collect and store solar energy. Passive systems involve careful architectural design and are related to good energy conservation techniques. Hybrid systems permit some energy transfer through natural means but also use outside energy for certain energy flows. These systems can be effective in minimizing temperature differentials which have been a problem in some passive designs.

The current U.S. stock of residential and commercial buildings totals some 70 million units. In 1978 the residential sector used almost 12 quads of energy for space and water heating and at least 6 quads were expended by the commercial sector for the same purpose. This amount of energy consumed for space and water heating is equivalent to more than 9 million barrels of oil per day (about 3.3 billion barrels per year), which is more oil than the United States imports each day and respresents about 23 percent of all the energy consumed in the United States in 1978.

Because of siting constraints, building constraints, and other physical, economic, and institutional limitations, it will not be possible to solarize every existing and future building. And, even where solar systems are feasible, in most instances economics dictate that the solar systems be sized to provide a portion of the

* Prepared by J. Glen Moore, analyst in energy technology.

building's energy needs (50 to 70 percent) with conventional fuels providing the remaining needs.

B. Known Resources and Reserves

Solar energy is essentially inexhaustible. However, limitations on the availability of materials which make up the collectors and other components of solar heating and cooling systems could restrict their implementation should the demand for systems exceed the industry's ability to keep pace with the market while keeping costs down.

C. Current Contribution to U.S. Energy Supplies

A survey of solar installations conducted by the Solar Energy Institute of North America (SEINAM), a private association, indicated a total of 87,965 active solar space conditioning or water heating systems installed in the United States at the end of 1978.[1] Other informed surveys have indicated the existence of 100,000 installations or more, with most used for domestic water heating.[2]

On an annual basis a typical solar water heater delivers the energy equivalence of two barrels of oil; a combined space and water heater system delivers about five barrels of oil equivalence per year. Assuming that 100,000 installations in the United States is a correct estimate, that all units are functioning properly, and that the mix of water heaters to combined systems is about 10 to 1, the current contribution of this technology to the U.S. energy supply is on the order of 150,000 barrels of oil equivalence per year. Compared to a total of 14 billion barrels of oil equivalence consumed in this country annually for all purposes, the contribution of solar space and water heaters at this time is negligible.

D. State-of-the-Art

It is generally agreed that the use of solar thermal energy to heat building space and provide domestic hot water is the solar applicaiton most nearly ready for widespread commercialization. A recent government survey indicated that 249 firms manufactured and sold almost 7 million square feet of collectors during the first half of 1979 (including swimming pool heaters) compared to 4½ million square feet manufactured during the last half of 1978.[3] The manufacturers (which may or may not have solar as their only line of business) are supported by a network of marketing and installation firms (which also may or may not be exclusively solar).

Despite the progress that has been made so far, the industry is not considered mature. A number of technical, economic and institutional problems must be addressed and resolved before solar space and water heating can be fully utilized as a national energy source.

Solar space cooling is technically linked with solar space and water heating, but there is a significant difference in the state of equipment development and market readiness between the two

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[1] Solar Energy Intelligence Report, May 28, 1979, p. 213.
[2] Special Energy Edition. Arthur D. Little, Inc., October 1979, p. 7.
[3] Solar collector manufacturing activity, January through June 1979. DOE. Energy Information Agency. October 1979.

applications. Several types of cooling technology have been demonstrated but further development is required before these systems are ready for marketing.

E. Current Research and Development

Given the advanced state of commercial readiness of solar space and water heating compared to other solar technologies, the Federal program has in general been more concerned with the commercialization of existing systems than with the R. & D. of new systems, although the program does include an R. & D. component. The philosophy has been that a product should be developed by the industry that will eventually use it. Accordingly, whenever possible DOE has supported the R. & D. efforts of industry rather than directing industry into new areas of research. An exception has been in solar cooling which has had, and continues to require, significant Federal R. & D. support.

An early deterrent to the commercialization of solar space and water heaters was the absence of experience with this application among architects, engineers, and builders, despite the fact that solar water heaters have been in use in this country intermittently since the 1920's. A major demonstration program was mandated by Public Law 93-409, the Solar Heating and Cooling Demonstration Act of 1974, to show how the various solar systems developed largely by industry could be used on all building types in each climatic area of the country. Annual cycles of demonstrations began in 1975 and concluded at the end of fiscal year 1979.

Approximately 12,000 individual projects are underway as a result of the Federal demonstration program, including single and multi-family housing totalling over 20,000 dwelling units in all 50 States (both passive and active systems), and approximately 400 commercial projects. About half the residential and commercial demonstration projects are operational at this time, and of these about 100 have been instrumented to provide detailed technical performance information.

An analysis of the residential portion of the solar heating and cooling demonstratioin program by the General Accounting Office (GAO) concluded that the program has had only limited success. The GAO found that: (*a*) based on a sample of 20 operational demonstration projects containing 91 residential units, the program has not clearly demonstrated the technical reliablility or the economic viability of solar heating systems; and (*b*) solar cooling technology is not ready for demonstration, which means that Public Law 93-409 needs to be amended to provide for demonstrations of this technology when its practicality can be proven.[4]

With no immediate plans for additional demonstration cycles beyond fiscal year 1979, DOE will concentrate its efforts over the next several years on product improvement and the removal of market barriers. The agency will continue to support installer and maintenance worker training programs, information and education programs, and development of codes and standards to assure consumer satisfaction. In addition, DOE will continue to fund some

[4] Federal Demonstrations of Solar Heating and Cooling on Private Residences—Only Limited Success. General Accounting Office. EMD-79-55. October 1979.

research and development work, and will support market testing, largely through the procurement of cost effective space and water heating systems for use in Federal buildings. The fiscal year 1980 budget request, post-revision, amounts to $45.2 million.

II. Prospects or Requirements for Further Development

The technical basis for solar space and water heating is fairly well known and accepted. However, problems still exist in systems costs, quality control, and overall performance, as well as in certain societal and institutional aspects of widespread implementation. The mass production of solar collectors is often mentioned as the key to low cost systems and a widespread commercial market. However, some manufacturers have indicated that increases in material and operating costs have cut their profits to the point where they do not expect prices to be substantially reduced by mass production. Opportunities for reducing collector costs, therefore, lie not so much in mass production but in the development of new collector systems that use less expensive components or less material more efficiently. Additional opportunities lie in the effective integration of existing components and in the design of systems that are less costly to install.

Specifically, current and potential development requirements include the following:

A. Improved Collector Performance and Cost Reduction

About half the price of a typical solar space or water heating unit is in "conventional" off-the-shelf components and much of the rest is in "conventional" materials.[5] There is no reason to expect decreases in real cost in either conventional components or materials in the future. Consequently, only limited cost-shaving improvements appear possible in current flatplate collector units. However, new concepts such as plastic collectors or evacuated tube collectors designed for volume production promise to reduce collector costs and improve performance.

B. Reduced Installation Costs Through Improved System Design

The installation cost of a solar system is often the single most expensive part of the project, involving field labor rates and dependence upon building configuration and weather. Systems engineering can provide better matching of components and, possibly, the complete packaging of fully integrated systems. The result should be an overall improvement in efficiency and streamlined (hence, less costly) installation procedures. DOE has indicated it intends to work more on systems development in the future.

C. Solar Assisted Heat Pumps

Hardware development efforts currently underway combine new heat pump concepts with solar heating, cooling, and hot water systems. These promise more cost effective systems. Advantages of

[5] Solar Engineering. August 1979, p. 40.

the new systems include maximizing solar input, assisting utility load balance, and providing a balanced heating and cooling system.

D. Chemical Heat Pumps and Storage

Chemical heat pumps based on thermally driven reversable chemical reactions are being developed on a limited scale of effort. The predicted economic performance of these systems is attractive. Because the systems include heating, cooling and storage in a single package, they could show a considerable savings over conventional solar systems when they are ready for the marketplace.

E. Integration of Conservation, Passive and Active Solar Design

Energy conservation, passive solar design, and active solar systems are engineering disciplines which have, to a large extent, been developed independently of one another. Opportunities remain for the development of market-acceptable system concepts that effectively combine all three approaches to reducing the need for conventional energy.

F. The Retrofit Market

Cost effective retrofit domestic hot water systems are available in certain regions of the country, but retrofit heating and cooling systems are not well developed. Techniques to facilitate the optimization of retrofit design are also not readily available. A significant contribution from solar in the future will require the retrofit of large numbers of existing building units as well as the solarization of a large portion of all new construction.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

1. STANDARDS

Rapid advances in solar technologies have left gaps in the technical standards required for industry development. The Federal program is aimed at accelerating the development of standards by providing assistance to standards developing groups in the private sector. The absence of standards or uncertainty about the standards that will ultimately be adopted is perceived to be a market barrier. Consumer rights advocates maintain that standards applicable to solar equipment and installations are needed to inform and protect the consumer with respect to the expected performance and basic quality of a producer. The challenge is to devise standards which give the consumer adequate protection without adversely affecting competition or stifling innovation in the industry.

2. BUILDING CODES

A traditional impediment to the introduction of new building technologies has been the lack of uniformity in the thousands of State and local building codes across the Nation. The DOE, in cooperation with State and local government officials and nationally recognized building code organizations, prepared a draft Model Code Document in fiscal year 1979 with final publication planned by fiscal year 1980. Speedy acceptance of the code would allow the solar industry to design equipment for a national market instead of having to tailor systems to meet local requirements. A national recognized code should make local building code officials more receptive of solar construction.

3. TESTING AND CERTIFICATION

The lack of understandable, uniform data regarding solar equipment performance makes it difficult for consumers, designers, and builders to select appropriate solar energy systems. The adoption of different equipment testing and certification procedures by public agencies and private sector organizations could result in buyer confusion and increased manufacturing costs. The DOE supports efforts in the private sector aimed at developing uniform equipment rating and certification procedures.

B. Economic

1. SOLAR HEATING

Experience in the Federal demonstration and in the commercial market has shown that the high first cost of solar space heating is the major obstacle to widespread consumer acceptance. Costs of active solar space heaters vary from $25/ft² to $40/ft² of collector area; systems in the first three cycles of the Federal residential demonstration program had an average installed cost of $32.77/ft² of collector area.[6] A typical active solar space/water heater system can cost $8,000 to $12,000 or more.

Rising fuel costs, an unstable economy, and the uncertain effect congressional actions such as the National Energy Act (Public Law 95–617 through 95–621), the Windfall Profits Tax (Public Law 96–223) and a variety of pending energy legislation may have on the energy market, make it difficult to determine when a solar application has reached economic viability in a given situation. In general, however, the 40 percent residential tax credit and 15 percent business tax credit [7] provided under the Windfall Profits Tax Act, and actions taken under the National Energy Act of 1978 which make conventional fuels generally more expensive, work to make investments in residential and business solar equipment more attractive now than ever before. Even before the credits and other congressional actions, solar water heating was competitive with electric water heating in many regions of the country.[8] With the credits, solar water heating could be competitive with electric water heating in new and retrofit applications in almost every region of the country. Solar space heating should be competitive in new construction in many regions where the alternative is electric baseboard heat, heat pumps or oil-fired furnaces. The economic outlook

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[6] Domestic Policy Review of Solar Energy. Final Report: Research, Design and Development Panel. DOE/TID-28837. October 1978: tab A. p. 7.

[7] Business can actually take a 25 percent credit for solar investments when the standard 10 percent investment tax credit is included.

[8] Bezdek, Rogher H., Alan S. Hirshberg, William H. Babcock, Economic feasibility of solar water and space heating. Science, vol. 203, Mar. 23, 1979: 1214-1220.

for retrofit applications for active heating systems is uncertain because of the many variables that must be considered in such application. Although passive solar is not eligible for a tax credit, well-designed passive solar heating and cooling systems can still be cost effective in new construction in many areas.[9]

2. SOLAR COOLING

The first high costs in active solar heating systems are a greater problem for active solar cooling systems. There are two reasons why this is the case: First, the equipment is more complex. The cooling equipment is not in volume production and involves a complicated technology. High temperature collectors are necessary for good system performance, and ancillary items such as cooling towers are currently necessary for good system operation. All of these add to system installation and operating costs. Second, the annual operating cycle for most residential solar cooling system is limited to a small part of the year. As a result, the high installation cost can only be written off over a limited part of the year.

The only current cost information for active residential solar cooling systems (lithium bromide and water absorption system) is derived from a limited number of Federal domonstration projects and quoted prices for the one type of system in the marketplace. Depending on system size and cooling load handled, the installed cost of an average three ton residential active solar system ranges from $25,000 to $30,000.[10] This is about 15 times the cost of conventional residential air conditioning systems of the same capacity (installed).

C. Environmental

Solar heating and hot water systems are generally considered an environmentally beneficial technology since conventional fuels will be displaced. Solar energy conversion is not totally free of environmental impacts, however. While the conversion processes may not cause significant air or water pollution, negative impacts are associated with the production of materials used in the collectors and other components, and with the manufacture of the components. Other environmental considerations relate to land use patterns, toxicity and flammability of solar working fluids and materials, and consumer safety implications.

D. Social

Escalating fuel costs for home heating affect the Nation's 20 to 25 million poor perhaps more than any other societal group. While these individuals might benefit most from the energy savings and the fuel-cost inflation protection that solar space heating would provide, they are the least able to afford the expense of solarization.

Preliminary Internal Revenue Service figures based on 89.3 million tax returns (94 percent of the returns filed in 1978) show that the group reporting an adjusted gross income of $10,000 or less filed 4.5 percent of all returns but made just 5 percent of all

[9] Passive solar applications are proposed to be made eligible for subsidized loans under Title V of Public Law 96-294, the Energy Security Act of 1980.

[10] Ibid., tab B, p. 4.

reported renewable resource expenditures. The $10,000 to $15,000 group filed 16 percent of all returns and reported 7 percent of the renewable resource expenditures; the $15,000 to $50,000 group filed 35.5 percent of the returns and reported 70 percent of the expenditures; and the over $50,000 group filed 2 percent of the returns and reported 18 percent of all renewable resource expenditures. Approximately 40 percent of all individuals filing returns used the 1040A short form. These taxpayers are generally from the lower income group. They would not be filing this form if they had renewable resource expenditures to report.[11] Pending a complete statistical breakdown of the 1978 tax returns, these preliminary figures suggest a direct relationship between income level and a tendency to adopt renewable resource measures.

Critics claim that the residential solar tax credit, as well as the proposed Solar Bank for subsidized low interest loans,[12] only benefit relatively well-off families since even with the Federal economic incentives the cost of solarization is beyond the means of low income groups. Getting an acceptable solar-use rate in the lower income groups is a challenging social issue requiring further study.

E. Political

1. DOE ORGANIZATION

The organization of the Federal solar energy program, which pits an applications branch against an R. & D. branch, has resulted in instances of understaffing and intradepartmental rivalries that have caused delays in certain programs. It has been suggested that organizational problems may have discouraged congressional solar proponents from seeking additional money for solar programs out of concern that DOE did not have the capacity to spend it properly.[13]

Energy Secretary Duncan reorganized the Federal solar program beginning September 1, 1979 but it is too early to assess whether old problems can be resolved by this new management structure.

2. FOREIGN MARKETS

While the Federal Government recognizes the overseas market potential and the possible foreign policy implications of an international solar energy market, an overall international solar strategy as one component of a U.S. international energy policy has not been formulated. The developing nations are particularly well-suited for using solar energy: They tend to receive a large amount of sunlight, and their population patterns lend themselves to decentralized energy sources. The high cost of conventional energy in the developing countries means solar technologies might be marketable in those countries before they are marketable domestically. Failure to establish early dominance in an international solar market could be a problem for U.S. solar industries seeking initial

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[11] Conversation with Phil Clark of the Internal Revenue Service.

[12] A Solar Energy and Energy Conservation Bank was established June 30, 1980, with the enactment of Public Law 96-294, the Energy Security Act of 1980.

[13] Donelly, Harrison H. Solar energy: A future that has yet to come. Congressional Quarterly. Sept. 15, 1979: 1987-92.

markets for their products. (See the discussion under Photovoltaic Energy Conversion, I.E.3.)

3. FEDERAL INCENTIVES

Experience with the adoption of the residential solar tax credit suggests that the time lag between the proposal of a Federal incentive for solar energy and its enactment into law can be a difficult period for the solar industry affected. Beginning in 1974 and through the first half of 1977, semiannual Government surveys of the solar collector industry had shown a steady, even predictable, semiannual increase of 50 percent or more in production. But during the last half of 1977, corresponding to the introduction of the tax credit proposal, the production of solar collectors increased by just 20 percent, and the first half of 1978 showed no increase in production over the previous period. During the second half of 1978, when the congressional debate over the National Energy Act and the much publicized solar credit was most intense, preliminary government figures indicate that collector production fell 27 percent, from 6.28 million square feet produced in the previous period to 4.58 million square feet. Many small firms reportedly failed during this period. It is not possible to determine the extent to which Federal delays on the tax credits were responsible for the industry's malaise in 1978. However, it is possible that the delays contributed to the downturn and to this extent Congress and the Administration may need to act more decisively on solar incentive legislation in the future.

4. COMPETITION WITH SYNFUELS

Competition with synfuels for limited Federal energy dollars could jeopardize prospects for achieving the national goal of a 20 percent solar contribution to U.S. energy supplies by the year 2000.[14] Estimates indicate that the Federal Government would have to spend $100 billion in R. & D. and direct market support over the next 20 years to achieve this goal.[15] Currently, the Federal solar budget is about $1 billion per year. An accelerated synfuels development program costing tens of billions of dollars over the next few years would put a heavy strain on the Federal energy budget and might prevent the solar program from getting the funding necessary to achieve this national goal. Further analysis is required to determine the possible impact a major synfuels program might have on established solar objectives.

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[14] The Solar Energy Domestic Policy Review, (DPR) published by DOE in February 1979, estimated that United States annual energy use would rise to 95 quads by the year 2000, assuming an increase in the price of imported oil to $32 a barrel. The DPR concluded that a maximum practical effort could increase the amount of conventional energy displaced by solar and other renewable resorces to 18.5 quads by the year 2000, from the present 5 quads which is obtained primarily from hydropower and the direct combustion of wood. This would be approximately 20 percent of the total, given the $32 a barrel price assumption. As a result of the DPR study, the President, in a speech made on June 20, 1979, committed the Nation to a goal of meeting "one-fifth—20 percent—of our national energy needs with solar and renewable resources by the end of this century." The goal established by the President assumes a strong, concerted effort by State and local governments, and private industry and individual energy users, in addition to the continuing Federal program.

[15] Dr. Paul Rapport, former director of the DOE Solar Energy Research Institute.

5. FEDERAL SUBSIDIES FOR CONVENTIONAL ENERGY SOURCES

Proponents argue that the widespread use of solar energy is hampered by Federal and State policies and market imperfections that effectively subsidize conventional energy sources. These policies include Federal price controls on oil and gas, a wide variety of direct and indirect subsidies, and utility rate structures that are based on average, rather than marginal, costs. The proponents further argue that the present energy market fails to adequately reflect the full social benefits and costs of conventional energy sources such as the costs of air and water pollution. They conclude that if solar energy were given economic parity with conventional fuels through the removal of these subsidies, its market position would be enhanced.

6. FUNDING PRIORITIES WITHIN THE FEDERAL SOLAR BUDGET

Although the current Federal solar R.D. & D. program is substantial, solar energy funding priorities have been critcized for not being more closely linked with national energy goals. According to some critics, solar R.D. & D. budgets, which have totaled about 1.5 billion in the fiscal year 1974 to fiscal year 1979 period, have not adequately concentrated on systems that have near-term applications and can help displace oil and gas. Also, the critics claim that electricity from large, centralized solar technologies has been overemphasized while near-term technologies for the direct production of heat and fuels, community-scale applications, and low-cost systems have not received a level of support commensurate with national energy independence objectives. On the other hand, it has also been argued that basic research on advanced solar concepts has been under-emphasized during this period, which could limit the long-term contribution of solar energy to the Nation's energy supply.

F. Utility Role

Utilities could either significantly assist in the increased use of solar energy or serve as a major barrier to such use. Utilities can hinder solar energy use by offering backup energy to users of solar equipment at discriminatory rates or by refusing to buy back solar-generated, system-compatible electric energy at reasonable rates. Utilities could enhance solar commercialization by giving their customers basic energy information, recommending reliable systems and installers, offering financing, leasing solar equipment, or even acting as a sales agent on arrangements where payment for a customer's solar unit would be included in the monthly utility bill. It should be noted, however, that some solar industry representatives oppose any utility role in solar development, fearing that regulated utilities with their financial resources could have an adverse impact on competition.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Estimates of the energy impact of solar space and water heating systems have varied widely and are speculative at this time. A House committee report refers to an estimate of potential savings in the residential sector alone of 1 million barrels of oil equivalence per day by 1990, or approximately a 2 quad annual saving.[16] This estimate is in sharp contrast to one DOE source which puts the combined solar contribution for passive and active solar heating and cooling, and solar pool heating, at just 0.26 quads in 1990.[17] About midway between these two estimates, the Domestic Policy Review of Solar Energy estimates that by 1990 active and passive solar energy systems in all types of residential applications will save on the order of 0.7 quads of primary energy. Commercial applications will save another 0.2 quads.[18]

The few available industry trends on which to base an estimate at this time do not bode well for the future of solar space and water heating. Indications are that the industry is falling far short of the installation pace needed to reach the goal of 2.5 million residential solar installations by 1985 which was set by the President in 1977 for the National Energy Act. "Solar State of the Union Report," issued in May 1979 by SEINAM, indicated that in order to be on target for meeting the President's goal, 283,000 units should have been installed in 1978, while the actual number totalled only 32,670 units. Looking ahead to 1979, SEINAM projected that 49,710 units will be installed, compared to 350,672 installations needed to keep pace with the goal. Unless unforeseeable events cause a dramatic increase in the installation rate over the next few years, the contribution of solar space and water heating to the national energy damand in 1990 may be less than estimated by DOE.

B. Contribution by 2000 or Beyond

In its Domestic Policy Review of Solar Energy, DOE projects that active and passive solar energy systems in residential and commercial applications will displace 2.4 quads of primary energy in the year 2000, with the largest saving (2.0 quads) in the residential sector.[19] This estimate assumes that solar energy will substitute for power generated by utilities. When displacing utility power, every unit of energy delivered by a solar installation saves 3 units of energy at the powerplant since powerplants typically operate at 33 percent efficiency. The energy actually delivered by the solar units is one-third the amount which DOE estimates will be displaced, or 0.8 quads in the year 2000. Assuming an average solar installation delivers the energy equivalence of 4 barrels of oil per year (water heaters deliver about 2 barrels per year, combined space/water heating units deliver about 5 barrels), 36 million installations would be required to fulfill DOE's estimate of 2.4 quads saving by 2000.

There is uncertainty inherent in any projection of this kind. The actual number of units in place in 1990 and beyond will depend upon the future cost of oil, Federal incentive programs, consumer perceptions and a number of other variables which are difficult to predict. While current trends suggest ever higher solar installation rates, the outlook could change suddenly by a dramatic break-

[16] National Solar and Energy Conservation Incentives Act. Committee Banking, Finance and Urban Affairs. Report 96-625. (To accompany H.R. 605) Nov. 15, 1979.

[17] Annual Report to Congress 1978. Vol. 3: Forecasts. DOE, Energy Information Administration. DOE/EIA-0173/3. 1979; p. 291.

[18] Domestic Policy Review of Solar Energy. A Response Memorandum to President of the United States. DOE. TID.22834. February 1979.

[19] Op. cit.

through in any one of a number of "new" energy technologies being pushed concurrently with solar space conditioning systems, or it could change gradually as progress is made in making more effective use of our conventional energy resources, and as conservation practices become more widespread.

SOLAR THERMAL POWER CONVERSION *

I. Survey of the Current Situation

A. Description of the Technology

Solar thermal technology entails using highly concentrating mirror configurations to produce high temperature heat. This thermal energy can then be used directly (industrial process heat applications or advanced solar heating and cooling), converted into electrical energy (utility or on-site generation), mechanical energy (irrigation pumping), or any combination of these (total energy schemes).

In addition to demonstrating considerable versatility in their ability to provide heat, electricity, or shaft work, solar thermal energy conversion systems can be sized from a few kilowatts (kw) to hundreds of megawatts (Mw). For example, the Federal solar thermal program, under the direction of the Department of Energy (DOE), has diverse projects such as 25 to 200 horsepower (18 to 150 kw) trough collector irrigation projects; intermediate size dish and spherical bowl collector projects which have rural as well as industrial applications; and large-scale projects such as the 10 Mw-electric central receiver at Barstow, California, which is designed to serve utility requirements.

Two basic solar thermal power system configurations are being studied: (*a*) the solar power tower concept, and (*b*) energy collection through distributed receivers. The power tower concept features a central boiler or receiver located atop a tower which could be as tall as an 85-story building for a 100-Mw system. The tower is surrounded by computer-controlled mirrors (heliostats) that track the Sun throughout the day and focus sunlight on the central receiver. Central receiver technology is being developed primarily for large-scale applications (greater than 10 Mw) under DOE's large solar thermal power systems program. The distributed receiver concept uses distributed collector systems and receivers through which the heated working fluid is piped from each receiver unit to the point where the thermal energy is converted into electricity. Distributed receiver technology involves trough, dish, and bowl collectors and is being developed primarily for smaller scale applications under the DOE's small solar thermal power systems program.

B. Known Resources and Reserves

While the solar resource is unquestionably large, the diffuse nature of solar energy necessitates the use of large collector areas for all but the smallest units. Solar energy is also intermittent both as a regular (diurnal) and irregular (weather) basis. The diffuse and intermittent nature of the solar resource tends to limit the potential for solar thermal power at this time to those applications

*Prepared by J. Glen Moore, analyst in energy technology.

where energy storage is either not required, or requirements would be so small that storage would not be a major constraint.

For utility applications, energy storage will initially have to be kept to a minimum, which means that solar powerplants will probably be limited to providng intermediate load electricity (the additional electrical power utilities must generate from about 7 a.m. to 9 p.m.). Solar powerplants are not expected to contribute measurably to the base load demand (maximum continuous demand) since their electric power production is limited to about six to eight hours per day. To provide base load power, a solar powerplant would require 16 to 18 hours of storage, plus enough extra collectors to fill the storage system. The result is that a solar base load system would require five megawatts of capacity to provide one megawatt of electricity on a continuous basis. Even more capacity would be required to store enough electricity to get through a cloudy day. Because sunlight is naturally coincident with intermediate electric demand, less extra capacity and storage are needed. Roughly twice the peak capacity plus six hours storage would probably be sufficient for western locations.

The southwestern region of the United States is a logical location for solar powerplants, both in terms of the availability of solar energy and the availability of low-cost, low-use land. The land area potentially available and suitable for solar plants would be ample to accommodate sufficient generating capacity to meet current national electricity requirements if other constraints on solar thermal energy conversion could be overcome.

C. Current Contribution to U.S. Energy Supplies

Except for a limited number of commercial and experimental small-scale solar thermal systems (used primarily for advanced solar heating and cooling applications) and a small number of Federal projects which produce energy intermittently on a experimental basis, solar thermal power conversion is not contributing to U.S. energy supplies at this time.

D. State-of-the-Art

Solar thermal power systems have proven technical feasibility and no scientific breakthroughs are needed for deployment. However, the technology for both small and large-scale systems is still very much in the developmental and demonstration stages. Substantial cost reductions must be realized before solar thermal power is widely competitive with conventional energy sources.

Some of the earliest experiments with solar energy in this country—dating back to 1870—involved solar thermal power systems to operate simple steam engines. Concentrating collectors were used to operate small heat engines and pumps for irrigation in the early 20th century. While there was no sustainable market for solar thermal power at that time, conditions required for success in the marketplace have improved. Today, industrial activity in the small power area has increased to the point where several companies now offer parabolic trough-type collectors on a commercial basis.[1] However, these systems which deliver energy at a cost of about

[1] Concentrating Collectors. Special Directory. Solar Engineering, June 1979, p. 27.

$15/MBtu are still a factor of 3 above DOE's 1990 cost goal of $5/MBtu.[2] Accomplishments in the private sector have led DOE to shift the emphasis of the small solar thermal power program from trough collectors to dish and bowl concepts which have higher temperature capability but are at a less mature state of development. Multimegawatt systems for the utility and large energy user markets are in the planning stage but appear to be years away from widescale commercial feasibility. Nevertheless, a number of large U.S. firms and a handful of smaller companies are now involved in developing components for high temperature solar thermal powerplants, with most of this research and development being funded by DOE.

E. Current Research and Development

1. U.S. PROGRAMS

Currently, the DOE solar thermal power systems program supports the development of concentrating mirror systems for both electric power generation and industrial purposes.[3] During 1978 and 1979 the solar thermal program reached a funding level of roughly $100 million per year; approximately $120 million has been appropriated in fiscal year 1980 (Public Law 96-69). The fiscal year 1981 budget request amounts to $117 million.

With engineering feasibility issues approaching resolution, the focus of the DOE program is shifting to cost readiness. Cost goals for concentrator systems have been established consistent with penetration in the major heat and power generation markets. In general, those goals are in the range of $1,000 to $2,500 per electric kilowatt, or roughly $5 per million Btus for heat. These system goals provide a framework for targeting subsystem costs. In particular, the aim is to reduce the cost of troughs, heliostats, dishes, and other distributed concentrators to $7 to $10 per square foot by 1990 (assuming mass production), and 25 percent to 50 percent lower by 2000.

The current program for solar thermal development emphasizes the commercialization of products by the early 1980s. Specific objectives are:

(*a*) Reduce cost for small systems to twice market value by 1983;

(*b*) Reduce cost for large systems to twice market value by 1985; and

(*c*) Demonstrate acceptable reliability, environmental characteristics, and maintenance costs.[4]

Program goals are being pursued by funding several concentrator system options. These include:

(a) *Power tower concepts.*—The 10 Mw central receiver pilot plant, now in the early stages of site activity near Barstow, California, represents the program's most visible thrust and the one

[2] Fiscal year 1980 DOE Authorization. Vol. I. House Committee on Science and Technology. Feb. 8, 1979, p. 272.

[3] Braun, Gerald W. This and much of the information in this section is based on a paper delivered by Braun at the Solar Energy Industries Association Annual Meeting, Aug. 9, 1979, San Jose Calif.

[4] 1980 DOE Authorization. Hearings before the House Committee on Science and Technology. Vol. I. Feb. 8, 1979, p. 226.

which has received the most critical attention. This project has claimed 30 percent of the program's three-year budget between fiscal year 1978 and fiscal year 1980. It is expected to be in operation in late 1981. While smaller than most present day powerplants, the Barstow facility will provide system design tests and collector production experience applicable to near-term use for central receivers. The total project cost of $123 million is shared by the participants of the program, with $15 million provided by Southern California Edison (SCE) and the Los Angeles Department of Water and Power. The DOE will provide and be responsible for all solar components and support systems; the utilities will provide and be responsible for the turbine-generator facilities as well as the plant site, connections to the SCE electrical system, and necessary support facilities. The project will be the first integration of solar thermal hardware into a functional power generating plant. The plant will be operated by the utilities under a cooperative agreement with DOE for a period of five years.

(b) Repowering concepts.—The concept of using solar for repowering involves central receiver systems built next to existing fossil-fired steam powerplants. Solar-generated steam delivered to the existing turbines of the fossil plant would reduce the consumption of oil and natural gas. Planning initiatives undertaken in 1979 for the conceptual design of solar repowering/industrial retrofit systems should provide the basis for future projects subject to funding availability.

(c) Receiver technology.—About 30 to 35 percent of the DOE Solar Thermal Power Systems budget is now applied to receiver engineering development.[5] This includes work on trough, bowl, and dish concentrators.

Sandia Laboratories of Albuquerque, New Mexico, leads the effort to develop trough concentrators. The program is concerned primarily with high temperature concepts with capabilities in the 400 degree to 600 degree F range for industrial process heat applications, although designs studies have also been done to explore higher temperature (up to 1000 degrees F) trough designs for utilities. The work in industrial process heat is being carried out in conjunction with DOE's Office of Conservation and Solar Applications. One joint project will use trough collectors to supply steam for enhanced oil recovery. Studies have been initiated which could form the basis for mass production of trough collectors.

The fixed hemispherical bowl with a moving receiver is one of most novel concepts in the DOE solar thermal program.[6] Texas Tech University is developing the prototype hardware for a five-megawatt experimental facility to be built on a site near Crosbyton, Texas. Construction is now underway on a 65-foot diameter, high-temperature prototype steam receiver module. The conceptual design of the Crosbyton plant calls for ten 200-foot diameter modules once the validation of the 65-foot module is complete. Although there is some question as to the economics of bowl concepts for electric applications between one and ten megawatts, other sizes and applications could prove attractive. Smaller applications

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[5] Braun, Gerald W., op. cit.
[6] Ibid.

for bowls, such as irrigation pumping, have yet to be carefully evaluated.[7]

Parabolic dishes offer the highest possible optical performance of any concentrator concept, as well as high temperature capability, minimum land use and a high degree of modularity.[8] Dish systems are potentially the most versatile concentrator approach. For heat and electricity production, they can be as small as a few kilowatts, which is well below the likely minimum size for central receivers. Furthermore, the possibility of total, or mixed heat/electric systems, adds to the potential for residential and commercial applications. The current parabolic dish program involves a system at a Shenandoah, Georgia knitware factory where an array of 750 degree F dish concentrators will provide electricity, heating and cooling, and low temperature steam needs. Peak electric output will be 400 kw. The component development is completed and prototypes of the dish are being tested.

2. FOREIGN PROGRAMS

Most major industrial nations have solar thermal power R. & D. programs. However, the overall foreign effort appears to be smaller than the U.S. program in terms of funding commitment and number, diversity, and size of projects.

Israel and the Soviet Union have two of the larger foreign solar energy programs, but their efforts are on near term technologies (space conditioning and water heating in Israel, space heating and windpower in the Soviet Union) with relatively little activity reported in solar thermal conversion.[9][10] Foreign activity in solar thermal energy conversion appears at this time to be concentrated in Europe with a number of countries participating, including Sweden, Switzerland, Austria, Greece, Germany, France, and Italy. France and Italy have been involved in the development of solar thermal energy systems more consistently and for a longer period of time than have other European countries.[11] The French have had eight to nine years of experience with the 1-Mw thermal solar furnace at Odeillo, and, among other projects, plan to construct, a 25-meter diameter, 40 kw-electric, fixed hemispherical bowl system called Pericles. Italy has a testing and developmental facility in Sant'Ilario where design work was completed on a 1-Mw-electric receiver which the European Economic Community will construct in Sicily by the end of 1980 or 1981. West Germany also has an ambitious solar thermal program and is developing a number of systems primarily for markets in developing countries.[12]

Faced with an overwhelming dependence on foreign oil, Japan initiated "Project Sunshine" in 1974 to explore the feasibility of using solar energy and other unconventional energy sources for a portion of its domestic energy needs. The major emphasis has been on residential space conditioning and water heating, but Japanese plans include the construction of a 1-Mw prototype solar thermal

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[7] Ibid.
[8] Ibid.
[9] Grossman, G., and A. Shitzer. Solar Research Around the World: Israel. ASHRAE Journal. February 1979: 40–44.
[10] Grunbaum, Rolf. Alternative Energy in the U.S.S.R. Environment. September 1978: 25–30.
[11] Selvage, Clifford S. Some European Solar Thermal Power Systems. Solar Age. July 1979: 9–11.
[12] Scott, David. Solar from Germany. Popular Science. February 1979: 76–77.

power conversion system and feasibility studies and subsequent construction of a large-scale solar furnace.[13]

II. Prospects or Requirements for Further Development

While the technical feasibility of a number of solar thermal conversion technologies has been demonstrated, the tecnology is not practical for most applications. Therefore, the Federal effort is primarily focused on the costs of components to enable initial market penetration to take place in the mid-term (1985-1995). The initial market is expected to be mid-temperature industrial process heat, irrigation, and solar cooling for parabolic troughs; remote electric sytems for parabolic dishes; and repowered utility and retrofit industrial applications for central receivers. The long-term (post 1995) market for solar thermal technology is expected to be mid-temperature industrial process heat for troughs; small community electric, total energy applications, and chemical processing for dishes; and bulk electric, high-temperature industrial applications, and fuels production for central receivers. Enhanced performance and reduced cost for near-, mid and long-term-solar thermal technologies are being sought through improved (e.g., lighter, fewer materials) collectors, higher temperature capabilities, and through utility and industry experience in field experiments.

A. Research and Development

1. ENERGY STORAGE

The development of thermal or electric storage systems should have a critical effect on the market for solar thermal systems. Without storage, all direct solar conversion systems are limited to a capacity factor of 20 percent or less in most of the United States. Short-term electric energy storage is expensive, and economical long-term bulk electric energy storage is not yet technically feasible.

2. BASIC RESEARCH

The achievement of the cost reductions envisioned by DOE will require fundamental work in materials and coatings technology, as well as work to develop innovative concepts for solar thermal components, subsystems and processes, including reliable heat exchangers and receiver units capable of withstanding repeated thermal shocks over their lifetimes.

3. HEAT ENGINES

Heat engines driven by external heat sources are necessary for widespread use of small-scale electric and pumping station applications of solar thermal energy. Only a few manufacturers produce engines adapted for solar systems, and these are primarily prototype or test engines rather than production models.[14] Cost reductions and efficiency improvements are necessary if heat engines are to receive widespread use. Efficiency is directly related to total

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[13] Overview of Energy Programs/Solar Energy Commercialization Status in Selected Countries. DOE. HCP/CS-4121. December 1978.

solar system cost in that an efficient engine requires smaller collector areas to do the same amount of work.

B. Commercialization

Solar thermal technologies are unlikely to make any significant market penetration before the year 2000 without both continued Federal research, development and demonstrations, and major Federal economic incentives. Such incentives could be aimed at either the supply or the demand sectors, and could include grants, accelerated depreciation, rapid amortization, tax credits, or numerous other options. Experience with Federal incentives to encourage market-ready solar technologies should be of value in selecting appropriate Federal incentives for solar thermal systems when the need arises.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

The technical questions associated with solar thermal energy conversion systems relate to reliability, performance, and long-term durability in actual use. Experience with real applications beyond initial pilot plants will be necessary to resolve these questions and establish user confidence.

B. Economic

Until inexpensive thermal or electric energy storage systems are available, solar thermal conversion for utility applications will only be able to compete with powerplants built to deliver peak or intermediate load electricity. For the foreseeable future, the need to maintain generating capacity continuously means that no utility—not even those in the most favorable locations—will be able to commit more than 15 to 20 percent of total generating capacity to solar units. Assuming solar powerplants do achieve economic feasibility, the most promising first market is for the repowering of existing oil- and gas-fired generating facilities in the southwest. Even here, solar will only displace intermediate or peak load capacity. Another potentially limiting factor is the prospect that other new technologies, such as high-Btu gas from coal or heavy oil recovery, could be less expensive than solar power and offer possible operational advantages. The outlook for dispersed solar for such applications as irrigation pumping or process heat requirements is more promising in the near term but the ultimate domestic market may be limited.

C. Environmental

The technology for solar thermal power conversion is still largely in the developmental stage. Thus, detailed knowledge of the environmental impacts is not available. Overall, solar thermal power should have a beneficial effect on the environment since deployment should result in a reduction in the consumption of fossil or nuclear fuels. The technology does, however, pose some specific local environmental problems related to (*a*) misdirected solar radiation, (*b*) land requirements, (*c*) impacts on local climatology and ecology, and (*d*) impacts of the accidental or emergency release of working fluids into the local environment. In addition, one controversial study indicates that the labor and materials intensive nature of solar thermal power conversion increases the health risk associated with this technology far beyond what might first be expected.[15]

D. Social

Societal impacts that could arise as a result of the deployment of solar thermal power systems for utility or community-scale operations relate to land and manpower requirements associated with plant construction. Because of their size, solar powerplants will tend to be sited in rural agricultural or desert areas. Typically these regions are characterized by isolated small towns or villages with minimal community services. The construction and operation of solar powerplants in these areas could seriously strain community resources and services. The influx of construction crew members and families and, later of operating personnel, could alter the entire socioeconomic infrastructure of the community in question. In addition, the increased availability of electrical power may attract new industry and thus create local boom town conditions with attendant scarcities and inflation.

E. Political

1. CENTRALIZED/DECENTRALIZED CONTROVERSY

The Federal solar thermal program has been criticized for overemphasizing large scale, long-term applications such as the central receiver concept, at the expense of small, dispersed systems which appear to have near-term applications. The DOE is now making adjustments in the solar thermal program in order to achieve a more balanced effort. One problem has been that, until recently, the dispersed concepts had not been well defined and, therefore, received little support. The balance between central and dispersed applications needs to be continually monitored to assure that available funding is apportioned in the most effective manner.

2. EXERCISING EXISTING FEDERAL AUTHORITY

Provisions of the Power Plant and Industrial Fuel Use Act of 1978 (one of the five bills comprising the National Energy Act) prohibit the use of oil or natural gas in new electric utility generation facilities or in new industrial boilers with a fuel heat input rate of 100 million BTU's per hour or greater, unless exemption is granted by DOE. Similarly, the Act encourages, and in some cases requires, existing oil and natural gas facilities to convert to coal or an alternate fuel. If diligently applied by DOE, these provisions could be used to encourage the construction of new solar thermal facilities (including repowering operations) to reduce utility dependence on oil and natural gas.

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[15] Inhaber, Dr. Herbert. Risk of Energy Production. Atomic Energy Control Board. Ottawa, Canada. AECB-1119. 1978.

IV. Potential Contribution to Future U.S. Supplies

A. Contribution by 1990

Solar thermal power is not a promising near-term technology for electric power generation. Direct thermal applications for advanced space cooling, irrigation, and industrial processes hold some promise for the near-term but the market potential is uncertain.

The present approaches to solar thermal electric conversion are in the early stages of development and demonstration. Even if economically attractive technologies were to become available before 1990 it would be costly and time-consuming to build a sufficiently large number of plants to impact significantly on the total energy supply. Therefore, any substantive solar thermal capacity for the utilities industry is a long-term proposition.

The outlook for direct thermal applications in this timeframe appears somewhat brighter. However, this technology also requires significant research and development in order to achieve cost reductions necessary to begin initial market penetration.

Given that solar thermal conversion will problably not be attractive for utility applications by 1990, and direct thermal applications will also require substantial development before commercialization can begin, the 1990 contribution of solar thermal energy to U.S. supplies is likely to be negligible.[16]

B. Contribution By 2000 or Beyond

The DOE estimates the market potential for utility application of solar thermal electric power generation is 0.4 quads of primary energy displacement by the year 2000.[17] The solar contribution resulting from direct thermal applications in industry and agriculture could be several times larger than the utility market by the year 2000, but the uncertainties are greater.[18] Potential markets for process heat and total energy systems (combined electric and thermal requirements) could be significant (2.0 quads according to DOE estimates) once the lifetime and operational and maintenance characteristics of cost-effective, dispersed solar thermal technologies have been demonstrated (see: Agricultural and Industrial Process Heat Applications of Solar Energy, Section IV).

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[16] Department of Energy Solar Energy Objectives Calendar Year 1980. COE/CS-0155. April 1980, p. 238.

[17] Domestic Policy Review of Solar Energy. A Response Memorandum to the President of the United States. DOE. TID-22834. February 1979: table 8.

[18] Domestic Policy Review of Solar Energy. Final Report (of the) Research, Design, and Development Panel. TID-28837. DOE. October 1978: tab "D", p. 12.

FLUID HYDROCARBON TECHNOLOGIES

HEAVY OIL

Survey of the Current Situation *

A. Description of the Technology

The production of heavy crude oil (10 to 20 degrees API gravity) is impeded by viscous resistance to flow in the reservoir at existing temperatures. The heating of heavy crudes improves their mobility and, thus, the effectiveness of their recovery. Heat may be introduced into the reservoir by injecting a hot fluid, usually steam or hot water; by burning some of the heavy oil in place in the reservoir; or, in rare instances, by electric heating.

1. INJECTION TECHNOLOGY

The injection of steam into a reservoir to recover heavy oil is termed steam soaking and steam flooding. Steam injection works by reducing oil viscosity around the producing well and maintaining a large fraction of the in place oil in a more mobile condition in areas "swept" by the steam. This reduction in viscosity increases the influx of oil to the producing well.

Steam soaking, also called cyclic steam injection or huff-and-puff, is a method in which steam is injected into a producing well for several weeks. The well is next shut in for a few days and then put back into production, often with large increases in output. This is essentially a well bore stimulation technique, and it is sometimes economic to steam soak the same well several times. However, oil recovery usually declines with each succeeding stimulation.[1]

Steam flooding is a continuous injection process which attempts to displace the oil in a reservoir in a manner similar to that of conventional waterflooding. The steam is pumped into injection wells and the oil is displaced to producing wells. However, because of the relatively high cost of steam production, sometimes the injection of steam is terminated, at an optimum time, after which cold water is injected to push the steam already in the reservoir toward the producing wells. First it is necessary to determine the maximum temperature desired at the producing wells and then to use this information to calculate the time at which steam injection can be terminated and cold water injection begun. Recoveries in the range of 30 to 40 percent of the in place oil have been reported for steam floods.[2] Steam recovery methods are estimated to have

* Prepared by Joseph P. Riva, Jr., specialist in earth sciences.

[1] Riva, Joseph P. Secondary and Tertiary Recovery of Oil. Subcommittee on Energy, House Committee on Science and Astronautics, U.S. Government Printing Office, October 1974, p. 24.

[2] Enhanced Oil Recovery. National Petroleum Council, December 1976, p. 169.

the potential for increasing the recovery of heavy oil from a primary production of 10 percent to as much as 60 percent of the original oil in place in a reservoir.[3]

2. COMBUSTION TECHNOLOGY

The mechanics of crude oil displacement in an in situ combustion operation is similar to that which occurs in a steam flood. A steam drive is generated in a heavy oil reservoir by the vaporization of reservoir formation water or of injected water. This is accomplished by igniting the in place crude oil and maintaining the burn and moving it along in the reservoir by continuous air injection. There are three variations of this process. Forward combustion is the process in which air is injected into a well and the burning front advanced away from that well, heating and displacing oil and water to surrounding production wells. In the reverse combustion process, a short term forward burn is initiated by air injection at what will eventually become a producing well. The air injection is then switched to adjacent wells and maintained there. This process is designed for viscous heavy oil that could not move through a cold zone in a forward combustion process. Wet combustion, or combined forward combustion and waterflooding, is a modified form of forward combustion incorporating the injection of cold water along with air to recover some of the heat which remains behind the combustion front.[4] The water is heated by the hot formation and provides a second sweep of the reservoir. The air requirement is lower with water injection and, at a constant injection rate, in place oil may be produced faster because of the more rapid movement of the combustion zone, the increased utilization of the available energy, and the increased volume of the fluid injected. The air-water combination thus minimizes the amount of air which must be injected and the amount of in place oil which must be burned to maintain combustion, and also improves the sweep efficiency. Fire-water flooding, properly used, can result in the recoveries up to 70 percent of the in place oil.[5]

3. ELECTRIC HEATING TECHNOLOGY

Nonselective electric reservoir heating techniques have been used on occasion to recover heavy oil.[6] Electrodes can be installed in water flood injection wells so that an electric current flows through the in place oil. The oil zone acts as a resistance heating element and electrical energy is converted to thermal energy. However, since current density is highest near the injection wells, most of the heating usually occurs within a few feet of the electrodes. Since it is usually more expensive to heat a reservoir with electricity than with steam, nonselective electric reservoir heating is

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[3] Geffen, Ted M. Oil Production to Expect From Known Technology. Oil and Gas Journal, May 1973, p. 75.

[4] Iyoho, Aniekan Willie. Selecting Enhanced Oil Recovery Processes. World Oil, November 1978, pp. 62–63.

[5] Geffen, op. cit.

[6] Harvey, A. Herbert and Samy A. El-Feky. Selective Reservoir Heating Could Boost Oil Recovery. Oil and Gas Journal, Nov. 13, 1978, p. 186.

useful only under rather special conditions and commercial applications of the process have been limited.[7]

B. Known Resources and Reserves

The original heavy oil in place in the United States is estimated to be between 110 and 125 billion barrels.[8] Of this total 61 billion barrels is estimated to occur in California, 33.7 billion barrels in Texas, 6.8 billion barrels in Louisiana, with the rest divided among Arkansas, Oklahoma, Wyoming, Kansas, Alabama, and Mississippi.[9] Since most heavy oils occur at rather shallow depths, it is unlikely that large volumes remain undiscovered in the United States.

The in place oil is never totally recovered from a reservoir. This is particularly true of heavy oil, which has a recovery efficiency much below that of the lighter oils. The total oil that is estimated to be recoverable from the known heavy oil reservoirs of the United States (using thermal enhanced recovery methods) ranges from 7.47 to 20.5 billion barrels.[10]

C. Current Contribution to U.S. Energy Supplies

Current heavy oil production from California, the State which accounts for most domestic heavy oil production, is about 360,000 barrels per day, when measured on a field-by-field basis. However, since the gravity of crude oil often varies according to its position in a reservoir, this volume is increased considerably, to over 500,000 barrels per day on a well-by-well basis.[11] Texas produces about 2,460 barrels of heavy crude per day; Louisiana, 2,370 barrels per day; Arkansas, 1,300 barrels per day; Wyoming, 850 barrels per day; Mississippi, 440 barrels per day; and Oklahoma, 200 barrels per day. This can be compared to a total domestic oil production of 8.3 million barrels per day in 1978.

D. State-of-the-Art

The technology for producing heavy oil is currently available. While any given technology can be improved, and heavy oil recovery technology is no exception, increased domestic heavy oil production is restricted primarily by economics and environmental constraints, rather than by a lack of technology.

The recovery of heavy oil by the application of heat requires the consumption of considerable amounts of energy. On the average, one out of every three barrels of heavy oil recovered is consumed on the site as fuel to generate well injection steam. In an in situ combustion operation a significant portion of the in place heavy oil is burned to produce the underground heat which aids in the recovery of the remaining oil. If the price of decontrolled heavy oil rises to a cost-per-BTU level near that of natural gas, given the

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[7] Ibid.

[8] Enhanced Oil Recovery., op. cit., pp. 182–183. And Technical Summary, Session C, Present Knowledge of Occurrences. First International Conference on the Future of Heavy Crude and Tar Sands, UNITAR, Edmonton, Alberta, Canada, June 4–12, 1979, Unpublished manuscript.

[9] Enhanced Oil Recovery., op. cit.

[10] Ibid. and Technical Session C, Present Knowledges of Occurrences, op. cit.

[11] Wilson, Howard W. Heavy Crude Decontrol Sparks Mixed Emotions. Oil and Gas Journal, Sept. 3, 1979, p. 30.

desirability of burning cleaner natural gas and thus saving on the cost of air pollution control devices for the steam generators, some heavy oil producers may sell all of their heavy oil and switch to natural gas as a generator fuel. However, if this substitution was applied in all heavy oil fields in California, as much as half of the State's natural gas production would be needed for heavy oil recovery.[12]

Even with thermal stimulation, heavy oil recovery ranges from only about 5 to 100 barrels of oil per day per well. Per well recoveries of over 100 barrels per day of heavy oil are rare in the United States. Thus, heavy oil recovery is as much as 100 times less than per well recovery from some giant fields that contain lighter crudes. As many as 100 times the number of wells needed for a conventional giant field would be needed for a similar sized heavy oil field to achieve the same rate of production. Since it is not economic to drill wells at this density, the heavy field necessarily would be produced at a much slower rate than the conventional field. However, many more wells would still have to be drilled in the heavy oil field than in the conventional oil field and expensive recovery techniques put into operation. The result even after this much increased investment, compared to the conventional field, is that less total oil would be produced and production would be slower. As one barrel of heavy oil is combusted, on the average, to produce the steam necessary to net two barrels of recovery heavy oil and further combustion is often necessary to heat the heavy oil so that it will flow in a pipeline, air pollution may become a problem. Thus, further expenditures are often necessary for air pollution control devices.

E. Current Research and Development

Research is in progress involving the recovery of heavy oil. One suggestion to improve the steam injection process is the "hot plate" heavy oil method. Heat is provided by injecting steam beneath the heavy oil reservoir by using horizontal holes directionally drilled under the reservoir in a radial pattern from a large diameter central well. This variation in steam recovery technology is designed to lessen the use of steam, thus saving on fuel, and to recover an increased percentage (estimated at up to 65 percent) of the in palce oil in a shorter period of time (estimated to be about five years).[13] A demonstration project has been tentatively planned.

The heat loss which occurs when steam is injected thousands of feet down a borehole is a serious problem for heavy oil producers. A borehole steam generator is under development at Sandia Laboratories which may assist in the solution of this problem. The generator counters down hole heat loss by replacing the usual 20 by 40 foot surface boiler with a combustion chamber small enough to enter the seven inch borehole of an injection well. The elimination of the surface boiler would also aid in the problem of air pollution. Currently several models of the down hole generator are

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[12] Hendon, Jim. California Heavy Oil Expansion Linked to Pollution Control Price. The Oil Daily, July 31, 1979.

[13] "Hot Plate" Heavy Oil Process Demonstration Due. Oil and Gas Journal, July 23, 1979, p. 35.

being tested, but a number of technical problems remain before any model becomes commercial.[14]

Another process, in the developmental stage, is one in which combustion gases are superheated above ground and pumped down the injection wells in a closed system. Initial tests have been successful, with a considerable increase in heavy oil production recorded.[15]

In the area of electric reservoir heating, a new technique has been suggested in which the heat is applied selectively to those parts of the reservoir that are bypassed by a waterflood or another recovery process. Techniques are available to concentrate the heat in desired portions of the reservoir. Mathematical simulation appears to be the best method available to predict the response of a reservoir to selective heating, but thus far the newer electrical techniques have not been field tested.[16] Although expensive, selective electric heating of heavy oil has been suggested for areas in which other thermal techniques cannot be employed because of air pollution problems. Another process similar to electric heating is radio frequency heating. In theory, a conductor pattern, based on the electrical properties of the reservoir and contained fluids, can be selected to assure that radio frequency energy generated in the reservoir is absorbed by the in place oil. This process may allow for the treatment of larger reservoir volumes than is permitted by the steam and combustion method, which often bypasses portions of the reservoir. Research on this process is underway.[17]

Federal research and development activities concerning the exploitation of heavy oil deposits are the responsibility of the Division of Fossil Fuel Extraction of the U.S. Department of Energy (DOE). Currently four DOE oil field projects are underway. These include steam floods, in-situ combustion projects, and deep steam injection. In most of the projects, the cost is shared with the contractor.[18] Currently four DOE supporting research projects are underway. These projects are concerned with heavy oil resources in Missouri and with the technical aspects of heavy oil recovery processes.[19] The DOE fiscal year 1980 Congressional Budget Request contained a Thermal Recovery program (for heavy oil) that had been greatly reduced from that of the previous year. Fiscal year 1980 base funding for heavy oil recovery projects was $7.25 million. The request for fiscal year 1981 was $7.9 million, an increase of $650,000. Areas considered necessary for continued support include the study of additives to improve the sweep efficiency of a steam flood and research on the extension of depth limits for steam injection projects.[20]

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[14] Heavy Oil: Can Technology Convert "Gunk" to Five Million Barrels Per Day of Fuel? Energy Research Reports, Aug. 27, 1979.

[15] Ibid.

[16] Harvey, and El-Faky, op. cit., p. 190.

[17] Heavy Oil: Can Technology Convert "Gunk" to Five Million Barrels Per Day of Fuel? Op. cit.

[18] Enhanced Oil and Gas Recovery and Improved Drilling Technology. Progress Review Number 20. Quarter Ending Sept. 30, 1979, U.S. Department of Energy, Division of Fossil Fuel Extraction, Bartlesville, Oklahoma, June 1, 1979, pp. 88-91.

[19] Ibid., pp. 92-96.

[20] Department of Energy. Fiscal year 1981 Congressional Budget Request. Vol. 6, Fossil Energy Research and Development, Energy Production, Demonstration, and Distribution, January 1980, p. 128.

II. Prospects or Requirements for Further Development

The President ordered that heavy crude oil be exempted from price controls, effective August 17, 1979. He also requested that Congress exempt heavy oil from the proposed excise tax on decontrolled oil. The Presidential order applies to oil from leases on which production prior to July 1979 averaged 16 degrees API gravity or less.

Before decontrol, heavy oil, like the lighter crudes, sold at three price levels, depending upon its classification. Lower tier or "old heavy oil" averaged about $5.50 per barrel; upper tier or "new heavy oil" and "released heavy oil" (also controlled) averaged about $11.75 per barrel; and the free market price of stripper heavy oil averaged about $15.50 per barrel. Since the average of upper tier and lower tier prices was about $8.60, owners of newly decontrolled heavy oil production received price increases averaging about $6.90 per barrel.

Of immediate concern to heavy oil producers was the Federal decision to limit the definition of heavy oil to 16 degrees API gravity, rather than using the more generally accepted API gravity figure of 20 degrees.[21] If the definition were changed to include heavy oil up to 20 degrees API gravity, an estimated additional 150,000 barrels per day of heavy oil would also be decontrolled. The definition of heavy oil has subsequently been changed to 20 degrees API gravity, but an excise tax of 30 percent on decontrolled heavy oil output was included in the Windfall Profits Tax Act.

Since successful techniques for the production and processing of heavy oil though expensive are now in use, an increased price will be an important factor in further development.

III. Potential Obstacles to R. & D. or Technology Implementation

The steam generators, which are used to produce the injection steam for thermally enhanced heavy oil production, have been the cause of substantial air pollution problems in California. Enforcement of Federal air quality requirements has resulted in the curtailment of the operation of some steam generators. The heavy oil producers feel that, unless air pollution standards are eased in Kern County and in other California heavy oil producing areas, the pace and the amount of the increase in heavy oil production will not meet the projections of the Administration.[22]

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

The Administration estimates that the order decontrolling heavy oil prices will stimulate heavy crude production, adding 200,000 barrels per day by 1985 and 500,000 barrels per day by 1990 to the current heavy oil production of about 500,000 barrels per day.[23]

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[21] Wilson, Howard W. Heavy Crude Decontrol Sparks Mixed Emotions. Oil and Gas Journal, Sept. 3, 1979, p. 30.

[22] Carter Orders Decontrol of Heavy Crude. Oil and Gas Journal, Aug. 27, 1979, pp. 38–39.

[23] Smith, Donna. Carter Decontrols Heavy Oil. The Oil Daily. Aug. 20, 1979.

B. Contribution by 2000 or Beyond

It appears that the amount of heavy crude oil in the world may be about equal to the amount of lighter crude oil. However, the distribution of these two kinds of oil is not uniform. The heavy crudes occur mostly in the Western Hemisphere, while the lighter crudes occur mostly in the Eastern Hemisphere. The heavier crudes are a much less desirable energy resource than the lighter crudes, for they are much more costly to extract and to process. However, as they have not been exploited to the degree of the lighter crudes, they remain available for development. Heavy oil development becomes more vital as the supply of the lighter crudes fails to match demand, causing oil prices to rise and shortages to develop. The extent to which domestic heavy oil can substitute for lighter oil depends upon economics, environmental constraints, and the total amount of recoverable domestic heavy crude, currently estimated to range from 7.47 to 20.5 billion barrels.

Heavy oil is currently being produced at a reserve/production ratio of about 100/1 in contrast to 9/1 for conventional oil. This rate can be improved by the year 2000 but it is not reasonable to expect that it will ever approach the 9/1 rate for conventional oil.

An increase in heavy oil production to 1 million barrels per day by 1990 would result in a reserve/production ratio of about 30/1. By 2000, it may be possible to increase production (and again lower the reserves/production ratio) but this does not appear likely, due to the slow recovery rates of heavy oil.

Nonetheless, heavy oil will play an increasingly important role in the domestic energy supply mix. It is a known resource with relatively short lead times for development.

OIL SHALE *

I. Survey of the Current Situation

A. Description of the Technology

Oil shale is a sedimentary rock containing various amounts of solid organic material called kerogen. When heated to about 900 degrees F, shale yields hydrocarbons and a variety of solid products, most of which represent unuseable wastes. The hydrocarbons, however, can be processed into liquid and gaseous petroleum products including middle distillate fuels (both jet and diesel) and gasoline. Shale oil is considered to be a synthetic fuel.

Oil shale may be processed either above or below ground. Aboveground processing, utilizing conventional surface or deep mining techniques, involves a sequence of three basic steps—mining, crushing, and retorting (heating)—to produce the desired hydrocarbon end-products. Below ground processing of oil shale differs from the above ground process in that retorting to produce oil and gas takes place underground, or *in situ*. The oil shale is fractured or broken underground by explosives and then heated by a controlled underground fire. Fuels produced from the oil shale are then pumped to the surface and collected.

B. Known Resources and Reserves

The emerging U.S. oil shale industry has primarily focused its attention on high grade oil shales, those containing twenty-five gallons or more of oil equivalent per ton. These resources, located in Colorado, Utah, and Wyoming, are estimated to contain more than 730 billion barrels of oil equivalent; 600 billion barrels in Colorado, almost 65 billion barrels in Utah, and 60 billion barrels in Wyoming.[1] Leaner oil shales containing ten to twenty-five gallons of oil equivalent per ton are estimated to contain roughly twenty-six trillion barrels of oil.[2] These resources extend to the limits of the Green River Formation in Utah and Wyoming and are also found in ten eastern and middle western States.[3]

The economic feasibility of commercial-scale processing technology has not yet been demonstrated in the United States. Therefore, U.S. oil shale deposits must be classified as a resource, rather than as a reserve.

This chapter deals only with the high grade, western oil shales, because these deposits are the focus of industry's commercialization efforts.

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* Prepared by Paul F. Rothberg, specialist in physical sciences.

[1] Cameron Engineers, Inc. Overview of Synthetic Fuels Potential to 1990. Denver, Colo., 1979, p. 9.

[2] U.S. Department of Energy. Commercialization Strategy Report for Oil Shale. (Draft) 1978. p. 1.

[3] Ibid., p. 2.

C. Current Contribution to U.S. Energy Supplies

Only experimental amounts of shale oil are currently being produced. Thus, the current contribution of oil shale to U.S. energy supplies is negligible.

D. State-of-the-Art

Above ground retorting processes thus far have been tested only in pilot plant facilities. Both industry and Federal oil shale technologists judge that several of these processes are now ready for scale-up and testing in commercial modules or units producing about 9,000 to 10,000 barrels per day.[4]

Several in situ processes have been tested over the last fifteen years. One of the processes closest to being commercialized, which uses a combination of underground mining and in situ combustion, has already cost its developers approximately $100 million for development and testing. To date, six experimental tests have been completed, resulting in both high and low rates of recovery efficiency. Several more years of continued work may be necessary before the reliability of this process has been proven. The developers estimate that this process will produce 50,000 barrels of shale oil per day by 1985 at a commercial facility in Colorado currently under construction.[5] This projection may prove too optimistic, but an assessment of its accuracy must await the results of further experiments by the developers. If low recovery rates are obtained in subsequent tests, commercial plans could be delayed.[6]

E. Current Research and Development

The Department of Energy (DOE), with the participation of industry, is conducting a research and development program on oil shale. The near-term objective of DOE's program is to improve the technology base for commercial projects that could be constructed by 1985. The DOE's current program includes work on various in situ processing technologies, production research on both eastern and western oil shale, and environmental studies related to in situ processes under development. This program's appropriation for fiscal year 1979 was $48.6 million and the fiscal year 1980 appropriation is $28.2 million. The fiscal year 1981 request is roughly $36 million.

DOE's long-term objective (post 1985) is to improve substantially the economics and environmental acceptability of oil shale processes. DOE's long-term program focuses on research on advanced surface and in situ process concepts that could result in improved energy efficiency, higher resource recovery, and/or reduced environmental emissions and residuals.

Based on the current and anticipated level of industrial activity, the private sector may invest more than $5 billion over the next 10 years in projects aimed at commercializing shale technology.[7] The private sector is also conducting research on several proprietary

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[4] For additional information on the state of oil shale technology see: U.S. Department of Energy. Oil Shale R.D. & D. Program Management Plan. (Draft). June 25, 1979. Appendix B.

[5] Personal communication with officials of the Occidental Petroleum Corporation, 1979.

[6] For additional information see: Cameron Engineers, Inc., op. cit., p. 16.

[7] For a detailed list of oil projects and associated investment plans see: Rothberg, Paul. CRS Issue Brief 74060 entitled "Oil Shale Development: Outlook, Current Activity, and Constraints."

processes; however, the amount spent on these efforts is unavailable.

Commercial or large oil shale plants are either operating or planned in Russia, Brazil, and China. Since the geological characteristics of these resources, the types of processes, and the institutional constraints associated with these projects differ from those associated with U.S. projects, foreign oil shale projects are expected to have minor effect on the development of a U.S. oil shale industry.

II. Requirements for Further Development

A. Research and Development

Based on a review of the current state of technology, DOE has identified the following technical needs that "should receive the highest priority" in its research, development, and demonstration (R. D. & D.) program:

(*a*) Technology for preparation of in situ retorting;

(*b*) Process operating procedures;

(*c*) Work on retort abandonment plans, i.e., necessary steps to seal underground processing chambers after oil recovery is completed;

(*d*) Water management techniques;

(*e*) Work on designs for large and small mining systems;

(*f*) Development of control instrumentation and methods for in situ retorting; and

(*g*) Guidelines to ensure the health and safety of workers.[8]

Over the long-term, additional research, development, and demonstration in these areas could advance the current state of technology. However, as discussed below in section II. C, commercialization activities, including projects testing modular retorting units, will probably have a more significant impact than R.D. & D. on fostering the near-term growth of the oil shale industry.[9]

B. Demonstration

See II. A, above.

C. Commercialization

By testing technology at the commercial or modular level, industry and government would gain experience in handling the institutional, regulatory, economic, and environmental constraints associated with large scale oil shale projects. Operation of commercial modules could foster the near-term growth of a shale oil industry by providing: (*a*) Information on actual air emissions and aqueous discharges; (*b*) information on the effectiveness of systems designed to protect air, water, and land quality; (*c*) experience in handling the problems of scaling-up existing processes; (*d*) experience in regulating and financing this developing industry; and (*e*) experience in dealing with other constraints facing oil shale projects. Research and development, which is performed in the laboratory or at small scale facilities, is not intended or designed to

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[8] U.S. Department of Energy, Oil Shale R. D. & D. Program Management Plan, op. cit., p. vi.

[9] A commercial plant using above ground technology could consist of a series of modular units, each unit producing roughly 9,000 to 10,000 barrels per day.

yield the same quality or type of information or experience that is gained in the commercialization of large scale modules or projects.

Companies seeking to produce shale oil are involved in a range of commercialization activities. Several companies have been working on the mine development and engineering design of commercial oil shale projects for over a year. Several other companies are waiting for the resolution of legal problems associated with proposed projects. Some companies have applied to the Department of the Interior to obtain land exchanges that, if granted, could encourage commercialization to proceed. Other companies are beginning to: (1) apply for Federal and State permits or certificates to construct and operate commercial plants, (2) apply for DOE funds to conduct project feasibility studies or to enter into cooperative arrangements with DOE, or (3) prepare for financial incentives to be offered by the SFC.

If the first few commercial modules prove economically feasible, technically reliable, and environmentally acceptable, the outlook for the industry would be substantially improved.[10] Some companies would then build a series of modules—perhaps five or six identical units each producing about 9,000 and 10,000 barrels per day—integrated into a commercial plant producing 50,000 barrels per day. Information on the expected costs of a commercial facility is provided in III. B, below.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

As previously discussed in Section I. D. above, the major technical barrier to above ground retorting is that the processes have not yet been scaled-up to the commercial module level. A major technical problem with some in situ processes is that these processes do not yet consistently yield a high return of product after every test and thus these processes are not commercially reliable.

B. Economic[11]

The economic constraints associated with oil shale commercialization are important factors limiting development in the United States. The emerging oil shale industry faces many economic uncertainties including:

(*a*) Future production costs which may increase substantially;

(*b*) The future competitive price of oil in international markets;

(*c*) The huge capital required to construct a commercial project; and

(*d*) The risks of major project delays, which could also substantially increase project costs.[12]

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[10] Some companies may skip the singular modular stage and simultaneously build a series of modules.

[11] The Synthetic Fuels Corporation, which is discussed later in this chapter, is authorized to provide an array of economic incentives to reduce the economic constraints described in this section.

[12] Cameron Engineers, Inc. Shale Oil Status Report. Denver, Colo., 1979, p. 20.

It has been suggested that the major problem facing the oil shale industry is the attraction of capital.[13] In view of the risks and uncertainties, many companies are reluctant to invest the $1.2–$2.5 billion necessary to construct an above ground plant or the $1–$1.1 billion required for an in situ plant, each producing about 50,000 barrels of fuel per day.[14] Even the largest companies obviously must carefully scrutinize an investment of this size.

Given current economic conditions and Federal policies affecting synfuels commercialization, some companies are continuing their cautious approach towards investment in oil shale facilities. Federal economic incentives, such as investment or production tax credits, prices supports, and possibly loan guarantees, could stimulate increased industrial activity. On the other hand, some companies have announced that they intend to move forward with proposed projects. Economic incentives provided by DOE or the Synthetic Fuels Corporation could accelerate the commercialization of oil shale technologies.

C. Environmental

The high quality U.S. oil shales are located in semi-arid, pristine regions of the country. A large scale industry, i.e., one producing roughly 100,000 to 200,000 barrels per day, might adversely affect human health and safety, fauna and flora, grazing and agricultural activities, and water and air quality. Some shale processing systems have been shown to release small quantities of polycyclic hydrocarbons, including some potentially carcinogenic agents. Surface fauna and flora might be distributed by commercial operations and by the disposal of huge quantities of tailings, or wastes. Mining operations could disturb the land and could result in mining injuries or deaths. Processing systems might pollute both water and air. However, a diversity of environmental control technologies, such as water effluent collection systems, revegetation practices, and gas cleaning operations, could reduce some of the adverse environmental impacts of oil shale development.[15]

In situ or underground mining of shale offers several advantages over conventional mining and surface processing, both economic and environmental. In situ processing could require less manpower, consume less water, emit less pollutants to the environment, and reduce significantly the quantity of spent shale wastes that require disposal. However, many of the environmental and occupational safety aspects of in situ processing, such as potential underground water contamination and the presence of workers underground during mining and combustion operations, have not yet been completed addressed.[16]

The developing oil shale industry faces other environmental or regulatory constraints, such as the complex array of Federal, State, and local environmental laws and standards. It remains uncertain whether commercial plants, incorporating appropriate pollution control technology and industrial hygiene practices, will meet all

[13] Ibid.

[14] The uncertainty associated with these estimates should be emphasized. Capital intensive projects, such as an oil shale facility, frequently experience substantial cost overruns. However, these capital requirements reflect a range of estimates cited in the literature.

[15] For a detailed examination of the environmental impacts of shale development see: Environmental Protection Agency. Oil Shale and the Environment. EPA-600/9-77-033. Washington, 1977.

[16] U.S. Department of Energy, Commercialization Strategy Report for Oil Shale, op. cit., p. 8.

applicable Federal and State environmental standards. Several companies have already spent several years seeking the numerous environmental permits required to operate commercial facilities.

In the press and before congressional hearings, environmental groups, representatives of western States, and others have expressed much concern over the potential environmental impacts described above. Adverse public reaction or opinion of these possible impacts, whether justified or not, has served as a constraint to oil shale development.

D. Social

High quality, western oil shale deposits are located in sparsely populated regions of the Western United States. A crash commercialization program would cause many adverse social and economic problems for many small, western towns that do not have the infrastructure to support the influx of construction and operation workers and their families. On the other hand, a shale industry would provide many new job opportunities and increase the tax base of many communities.[17]

E. Political

The emerging oil shale industry faces many political constraints, including complicated Federal and State regulatory policies, uncertainty regarding environmental standards, and changing Federal economic policies affecting commercialization. Many companies have complained to Congress that there is no clearly defined and coordinated Federal policy which clearly specifies the Federal role in oil shale development. Until recently, Congress had not yet passed a law providing substantial incentives that would encourage commercialization. The lack of a "Federal Oil Shale Policy" created major problems and uncertainties for industry. For example, a company planning to invest in a project had to make substantial financial decisions without knowing: whether the Federal Government would sponsor its own commercial projects; the terms under which additional Federal shale properties would be leased; whether major Federal economic incentives would be provided to promote production; and the effect of Federal environmental policies on oil shale operations.[18]

However, the 96th Congress has devoted much attention to legislation that will affect synfuels commercialization and that could help clarify the Federal role in this area. Two new initiatives that received considerable attention were proposals to create the United States Synthetic Fuels Corporation (SFC) and the Energy Mobilization Board (EMB). The SFC is authorized to provide major economic incentives for commercialization and the EMB might have expedited regulatory decisions affecting commercialization. Thus, these agencies might have significantly influenced the feasibility of com-

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[17] For additional information on the expected social-economic impacts see: U.S. Congress. Senate. Committee on Environment and Public Works. Inland Energy Development Impact Assistance. 95th Congress, 1st Session. (Washington, Government Printing Office, 1977).

[18] Examples of these and other uncertainties associated with the Federal role in oil shale development are cited in: U.S. Congress. Senate Committee on Energy and National Resources. Energy Supply Act. (Titles III, IV, and V). 96th Congress 1st Session. (Washington, Government Printing Office, 1979).

mercial oil shale plants by reducing many of the uncertainties previously discussed.[19] However, only the SFC legislation was enacted into law.

F. Legal

Two major legal problems that were previously associated with oil shale commercialization were: (*a*) Pending lawsuits filed by the State of Utah and Colorado that seek title to Federally-owned shale lands, and (*b*) contested ownership of 43,000 acres to unpatented mining claims filed on oil shale properties that were claimed under the Mining Law of 1872.[20] Due to these legal problems, several companies have suspended since about 1977 work on two certain tracts of the Federal Prototype Oil Shale Leasing Program. However, the U.S. Supreme Court in May and June 1980 issued two decisions that affect these legal constraints; however, the long-term effect of these decisions on the future of oil shale development remains uncertain.

G. Water Supply Constraints

Commercial oil shale projects will require substantial quanties of water from the Colorado River Basin, which is in a semi-arid region of the country. Realizing this need, development companies have undertaken major efforts to obtain high-priority water rights, which would ensure a reliable supply of this resource. For example, many companies have acquired substantial water rights over the last thirty years. Western water law generally follows the appropriation principle that earlier acquired water rights shall have priority over later acquired water rights. Thus, it appears that many companies have some legal rights to use western water resources as provided by conditional state decrees.[21]

The extent to which oil shale operations will adversely affect agricultural and other water consumers is uncertain. Factors that will influence the extent of future water problems include: the source and amount of water needed for oil shale projects and other energy projects in the Colorado River Basin, the source and amount of water needed for agricultural and other users, and water rights in this region of the country. Some shale developers intend to supply all process water for initial development from underground saline aquifers. Other companies either own direct diversion water rights on the Colorado River, have purchased option rights on proposed new Colorado River Water Conservation District reservoirs, or are negotiating for supplemental water supplies from existing Water and Power Resources Service Reservoirs. However, if agricultural users are unwilling to sell water rights to energy companies, oil shale development might be limited in some areas. The availability of water will remain over the long term a dominant constraining factor for both energy and agricultural production in the west.[22]

As indicated above, the amount of water used by oil shale developers is an important factor that will affect the future water supply problems of the Colorado River Basin. The amount of water

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[19] Legislation creating the EMB is still before Congress.

[20] Cameron Engineers, Inc. Shale Oil Status Report, op. cit., p. 19.

[21] U.S. Department of the Interior. Final Environmental Statement for the Prototype Oil Shale Leasing Program. (Washington, Government Printing Office, 1973), p. II-30.

[22] Cameron Engineers, Inc., op. cit., pp. 13-15.

required for oil shale will depend partly on the type of process that is used. Several processes have recently been advanced that require substantially less water than older processes. For example, using the modified in situ process should considerably reduce water consumption. One estimate indicates that plant water consumption could be reduced some twenty percent by using this technology in lieu of surface processing.[23] Technology to recycle water used in oil shale operations can also increase the efficiency of using water.

The actual amount of shale oil production will also influence the extent of future water supply concerns. Many industry and Federal officials have recently reduced their forecasts of the level of shale oil production expected by 1985 and 1990. Concurrently, forecasters have also reduced the projected water requirements for near-term shale oil production. Some researchers have suggested that the water-short Upper Colorado River Basin, where the major deposits of oil shale are located, should have sufficient water for energy development until at least 2000.[24] However, other groups have frequently stated that supplies of western water resources may be constrained by arguments over water rights and environmental restrictions and that shortages of water may occur in specific areas.[25]

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

As previously indicated, there are long lead times and uncertainties associated with commercialization. Considerable time is required to start a small plant, to learn by actual operation, to optimize new or improved designs, and to construct new operating units. This process can take about eight or nine years.[26]

If the first commercial modules or plants are commercialized by 1986 or 1987 and if the Federal Government provides substantial economic incentives, the current and anticipated level of industrial activity indicates that a production level of 60,000 to 250,000 barrels per day could be reached by 1990.[27] The upper level could be reached if major Federal economic incentives—either price supports, guaranteed purchases, or tax incentives—are provided, and if environmental regulations or legal proceeding do not significantly delay production. If industry encounters major technical regulatory or environment problems during the first few years of commercial operations, production may reach only 60,000 barrels per day or, perhaps, even less.

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[23] Comptroller General of the United States. Water Supply Should Not Be An Obstacle To Meeting Energy Development Goals. CED 80-30. January 1980, p. 22.

[24] Ibid., p. iii.

[25] U.S. Water Resources Council. The Nation's Water Resources 1975-2000. Second National Assessment. (Washington, Government Printing Office, 1978).

[26] U.S. Congress. House. Committee on Science and Technology. Oversight on Alternative Liquid Fuels Technology. 96th Congress, 1st. session (Washington, Government Printing Office, 1979), p. 218.

[27] Similar range of estimates has been prepared by Cameron Engineers, Inc., see: Cameron Engineers, Inc. Overview of Synthetic Fuels Potential to 1990, op. cit., p. 100.

B. Contribution by 2000 or Beyond

At the current stage of industrial development, estimates of shale oil production beyond 1990 are highly speculative. Should production reach 100,000–500,000 barrels per day by 1990, it seems reasonable to expect that roughly 180,000–450,000 barrels per day could be produced by 2000.[28] The uncertainty associated with any estimate of long-term shale oil production should be emphasized. Production levels beyond 1990 could be influenced by numerous factors, including: (*a*) The price and availability of world oil; (*b*) the price differential between conventional oil and shale oil; (*c*) the success of oil shale operations during the 1980's; (*d*) the effects of Federal policies on the growth of an oil shale industry; (*e*) the availability of water, and (*f*) the industry's ability to meet pollution standards.

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[28] Similar range of estimates has been prepared by CONAES, see: Committee on Nuclear and Alternative Energy Systems. (CONAES) U.S. Energy Supply Prospects to 2010. (Washington, National Academy of Sciences, 1979), p. 88.

UNCONVENTIONAL GAS *

I. Survey of the Current Situation

A. Description of the Technology

Unconventional gas is usually considered to occur in four geologic environments: dissolved or entrained in hot geopressured waters; in joints and fractures or absorbed into the matrix of Devonian age shales; in tight (impermeable) sandstones; and in coal seams.

Although there is no gas known to be produced from geopressured zones, the technology to drill and produce geopressured fluids is available. Drilling equipment for deep wells has been improved over the past several years and is now considered adequate for the mechanical loads, pressures, and temperatures that will be encountered in 20,000 foot geopressured wells.[1]

The technology for producing gas from Devonian shales includes drilling (a mature technology) and well stimulation by either explosives or hydraulic fracturing. Traditionally, Devonian shale wells have been stimulated by "shooting" with explosives. However, more expensive normal hydraulic fracturing (pumping a fluid under high pressure into the shale formation) may increase recovery compared to shooting, and is being used more often as gas prices rise.

Tight gas sand wells are also stimulated by hydraulic fracturing. With tight gas sands, however, massive hydraulic fracturing is used. Massive fracturing is a volume designation only. Since tight gas sands are massive, it is not possible to penetrate them effectively with the 30,000 to 50,000 gallons of fluid normally used. Stimulation effectiveness can be improved with extremely large volumes and with fluid-diversion techniques. Massive fracture stimulation can require a half million gallons of gelled fluid and a million pounds of proppant sand (used to keep the fractures open when the gel is removed).[2] It is desirable to achieve a single propped open, vertical or near-vertical fracture, which extends outward from 1,000 to 2,000 feet in opposite directions from the well. The height of the fracture could vary from 100 to 500 feet and provide a pressure sink and channel for gas to flow from the gas saturated zones to the well.[3]

Proved technology is at hand to produce gas from permeable coal beds by horizontal drilling into virgin coal from shaft bottoms; by horizontal drilling into virgin coal from outside entries of advanc-

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* Prepared by Joseph P. Riva, Jr., specialist in earth sciences.

[1] Boyd, W. E. Drilling and Completion Procedures for a Geopressured Water Producer. Paper presented at American Gas Association Seminar on Geopressured Gas Resources, Arlington, Va., June 13, 1978.

[2] Massive Frac Succeeds on Deep Mesaverde Gas. Oil & Gas Journal, Jan. 13, 1975.

[3] Natural Gas From Unconventional Geologic Sources. Board on Mineral Resources, Commission on Natural Resources, National Academy of Sciences, Energy Research and Development Administration, FE-2271-1, 1976, pp. 128-9.

ing underground mines, with the piping of the gas to the surface; and by drilling vertical wells from the surface into coalbeds, followed by stimulation to increase flow rates.[4]

B. Known Resources and Reserves

The most recent U.S. Geological Survey assessment of domestic geothermal resources estimates the recoverable methane contained in the geopressured deposits of the Gulf Coast to range from 158 to 1,640 trillion cubic feet.[5] Another study places technically recoverable geopressured gas in the Gulf area at 42 trillion cubic feet.[6] Other much larger resource base figures have been proposed, but these figures do not take into account the factor of recovery, which will be only about 5 percent of the in place fluids. It is also important to note that the estimates given are of resources and not of reserves. Geopressured gas reserves are zero. There are no known geopressured gas deposits which can be economically extracted using existing technology and whose volume has been estimated from geologic evidence supported directly be engineering measurements.

The U.S. Geological Survey estimated, in 1976, the in place Devonian shale gas resource to be between 500 and 600 trillion cubic feet.[7] Since recovery is estimated to be between 2 and 10 percent of the inplace gas, due to the low permability of the shales, recoverable gas resources would range between 10 and 60 trillion cubic feet. A 1979 DOE-industry assessment estimates potentially recoverable Devonian shale gas in the eastern United States to be between 200 and 900 trillion cubic feet.[8] It is again important to realize that these are not reverse figures. There are about 10,000 wells currently producing gas from the Devonian shale. Rates of production are generally low, but long lasting. Reserves of Devonian shale gas have been calculated from the geological and engineering data from these wells. Using this method the total ultimate recoverable Devonian shale gas reserves were estimated in 1976 to range from 2.56 to 3.38 trillion cubic feet.[9]

The amount of natural gas that might be recovered from very tight gas sandstones in the United States is quite speculative. The in place gas has been estimated to be 600 trillion cubic feet in the Mesa Verde formation in three major Rocky Mountain basins with another 600 trillion cubic feet postulated for other geologic provinces.[10] If the 600 trillion cubic feet figure is used, 40 to 50 percent of this (240 to 300 trillion cubic feet) might be recovered if an

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[4] Ibid., p, 195.

[5] Muffler, L. J. P. Assessment of Geothermal Resources of the United States—1978. Geological Survey Circular 790, Arlington, Va., 1979, pp. 159–60.

[6] Kuushraa, Velo A., J. P. Brashear, Todd M. Doscher, Lloyd Elkins. Vast Potential Held by Four "Unconventional" Gas Sources. Oil & Gas Journal, June 12, 1978, p. 53.

[7] Dewitt, Wallace. Current Investigations of Devonian Shale by the U.S. Geological Survey. Natural Gas From Unconventional Geologic Sources. National Academy of Sciences, Washington, D.C., 1976, pp. 113–115.

[8] Project Assesses Eastern Shale Gas Resource. Oil & Gas Journal, Oct. 22, 1979, p. 26.

[9] Brown, Porter J. Energy From Shale—A Little Used Natural Resource. Natural Gas From Unconventional Geologic Sources. National Academy of Sciences, Washington, D.C., 1976, p. 90.

[10] Elkins, Lloyd E. The Role of Massive Hydraulic Fracturing in Exploiting Very Tight Gas Deposits. Natural Gas From Unconventional Geologic Sources. National Academy of Scienes, Washington, D.C., 1976, p. 128.

effective stimulation technique were developed.[11] Again, this is not a reserve figure. Production from tight gas sands is currently about 1 trillion cubic feet per year, and it is from these wells that reserves would have to be calculated. If the reserves/production ratio of 10/1, which is applicable in conventional oil and gas deposits, is applied to tight sands, reserves would be about 10 trillion cubic feet.

The amount of gas contained in coalbeds in the United States has been estimated to be at least 300 trillion cubic feet.[12] This is a resource base figure which could be extended as additional information becomes available on the thickness and continuity of deeper coal formations.

The initial target for recovering natural gas from coal seams is the 80 billion cubic feet of gas emitted annually from working coal mines.[13] This figure may be considered as being similar to a reserve. There is currently no production of natural gas from coal purely on a commercial basis; it is all vented.[14] However gas has been produced from coalbeds in three demonstrations by the Bureau of Mines. Two of these projects delivered gas to an interstate pipelines.[15]

C. Current Contribution to U.S. Energy Supplies

There is no commercial gas production known to be derived from a geopressured deposit. Yearly production from Devonian shales is estimated to be about 100 billion cubic feet.[16] Gas production from tight sands is currently about 1 trillion cubic feet per year, or about 5 percent of domestic gas production.[17] There is no purely commercial production of natural gas from coal seams; the gas is all vented.[18]

D. State-of-the-Art

Drilling methods and equipment for geopressured wells are considered to be adequate. To produce the gas, high flow rates of the hot saline geopressured fluids must be maintained in areas of thick formations of high porosity and permeability. The erosion of equipment by sand present in the produced fluids must be controlled.

Normally, Devonian shale gas wells drilled by conventional methods are stimulated by "shooting" with solid explosives. Recently, however, attention has shifted toward hydraulic stimulation (fracturing) and liquid explosives. Such treatment has met with varying degrees of success.

Massive hydraulic fracturing is necessary to produce gas commercially from a tight sandstone. In an experimental well, vertical cracks that extended as far as 4,000 feet from the well, were opened at depths of from 9,000 to 11,000. Thus, extensive fracturing can be accomplished. The test well, however, was not successful in terms of gas production. Geological conditions are not uniform in

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[11] Luetkehans, Gerald R. Gas in Tight Sands. Natural Gas From Unconventional Geologic Sources. National Academy of Sciences, Washington, D.C., 1976, p. 167.

[12] Deul, Maurice. Natural Gas From Coalbeds. Natural Gas From Unconventional Geologic Sources. National Academy of Sciences, Washington, D.C., 1976, p. 194.

[13] Kuuskraa, Vello A., et. al., op. cit., pp. 51-2.

[14] Ibid.

[15] Deul, op. cit., p. 195.

[16] Kuuskraa, Vello A. et. al., op. cit., p. 51.

[17] Department of Energy, personal communication, Nov. 19, 1979.

[18] Kuuskraa, op. cit.

tight gas sands areas, which accounts for the success of some projects and the failure of others.

The technology exists to produce gas from permeable coal beds by both horizontal and vertical drilling. However, since coal is impermeable, the gas must flow either through the natural fracture system in the coal or diffuse through its micropores. Production rates and duration of production have been too low or uncertain to offset the costs of well drilling, water removal, compression, piping, stimulation, gas purification, and gathering costs all associated with the commercial recovery of methane from coal seams.[19]

E. Current Research and Development

The Department of Energy (DOE) 1981 budget request for the unconventional gas development program was $30.548 million. The goal of the program is to achieve meaningful increases in the levels of production of natural gas from marginal wells and from unconventional gas resources.[20] The principal objectives of the unconventional gas development program include the acceleration of the development and utilization of natural gas from coal seams, Devonian shales, and tight gas sands. The $30.548 million fiscal year 1981 request is divided into $12.4 million for tight gas sands; $12.4 million for Devonian shale gas; and $5.0 million for gas from coal seams.[21] The balance is for environmental support and capital equipment.

Under the Geothermal Program, the DOE requested $36.0 million for fiscal year 1981 geopressured resources programs, initially to emphasize gas recovery.

The Eastern Gas Shales project is an effort directed toward increasing natural gas production from the Devonian shales of the Appalachian, Illinois, and Michigan Basins. Work underway includes: an assessment of the gas potential of the Michigan basin; well stimulation tests in the Appalachian Basin; test well drilling in the Illinois Basin; foam fracturing tests for Devonian Shale stimulation; and methematical modeling of fluid flows in shale reservoirs.[22]

The Western Gas Sands project is an effort directed at greatly increasing gas production from the low permeability (tight) gas sandstones of the Western and Southern United States. Initial emphasis has been placed on the Picenace (Colorado), Unita (Utah), Great Plains (Montana and North Dakota), and Cotton Valley (Texas) areas. Geological assessments of these areas are underway. Drilling and logging of wells in which to initiate stimulation of the gas reservoirs is also in process. Mathematical models of fluid flow and proppant transport are being developed; and environmental regulations and restrictions related to drilling, stimulation, and gas production are being studied.[23]

In order to demonstrate the feasibility of methane recovery from coalbeds, an effort is underway to quantify the resource through

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[19] Ibid., p. 53.

[20] Department of Energy. Fiscal year 1981 Congressional Budget Request. Vol. 6, Fossil Energy Research and Development, Energy Production, Demonstration, and Distribution, January 1980, p. 146.

[21] Ibid.

[22] Ibid., p. 148.

[23] Ibid., p. 149.

cooperative coring and testing programs with industry, to verify production prediction models, and to assess possible effects on unmined coalbeds of extraction techniques that could be incorporated into future mining plans. Tests of technology, such as a turbodrill to drill a hole directionally into a western coal seam are also underway.[24]

The geopressured resources program will attempt to assess the geopressured resource to identify optimum reservoirs for commercial production; to identify incentives to stimulate private development; and to seek to resolve institutional, legal, and environmental barriers to development. Gulf Coast wells are being drilled and tested for geopressured resource production by DOE.[25]

II. Prospects or Requirements for Further Development

The major requirement for the commercialization of a larger portion of the unconventional gas resource is increased economic incentives. A special incentive price of 150 percent of the price allowed as of October 1979 under the National Gas Policy Act for new, onshore production wells has been proposed for gas from tight sands by the Federal Energy Regulatory Commission. The price would be allowed to escalate under the monthly inflation and adjustment factor prescribed by the Act.[26] The proposal contains a simple legal definition of a tight formation: tight formations are those which have low production rates due to low permeability, for which an appropriate tight formation enhanced recovery technology is available. An appropriate stimulation technology requires that the method increase production rates substantially and be more expensive than usual techniques.[27] A preliminary list of tight formations in the West considered candidates for tight formation classification has been compiled, with further additions expected later. Wells drilled into these formations must be expected to produce an average of 200,000 cubic feet of gas per day or less with no stimulation.[28] The well drilled into a tight formation must have been spudded[29] on or after August 17, 1979. No new well drilled into a reservoir which can be effectively and efficiently drained by an old well can qualify as a tight formation well under the proposed rule.[30] Once an area is designated as a tight formation, any well completed in the formation will qualify for the incentive price; regardless of actual production figures. At present only hydraulic fracturing and explosive fracturing are proven commercial, tight sand stimulation methods, although other techniques may be developed later.

Also, the Federal Energy Regulatory Commission officially lifted price controls on certain categories of unconventional gas on November 1, 1979, by issuing interim regulations defining the unconventional gas categories eligible. The gas categories eligible for free-market pricing under Federal Energy Regulatory Commission

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[24] Ibid., p. 149-50.
[25] Riva, Joseph P. Energy Potential of Gulf Coast Geopressured Deposits. Congressional Research Service, Library of Congress, Report No. 79-18 SPR, TN 880, pp. 17-24.
[26] Incentive Price Proposed for Tight Natural Gas. Oil and Gas Journal, Sept. 10, 1979, p. 260.
[27] Ibid.
[28] Ibid.
[29] "Spudded" is a technical term meaning that actual drilling has commenced.
[30] Ibid.

definitions included: production from geopressured brine, with at least 10,000 parts per million sodium chloride and initial pressure gradient in excess of 0.465 pounds per square inch for each vertical foot of depth; production from coal seams; and production from Devonian shale.[31] In order to be eligible to sell such high cost gas at an unregulated price, a producer must obtain a determination from a State jurisdictional agency that the wells involved are drilled into one of the three high cost formations.

On the basis of required information, in the form of well logs and tests, the State jurisdictional agency will make a preliminary determination as to whether the well does qualify. Notice of this determination is then sent to the Federal Energy Regulatory Commission which has 45 days for review. The determination will become final after this period of time, unless the Commission has found reason for reversal.[32]

III. Potential Obstacles to R. & D. or Technology Implementation

While the most popular characterization of the tight gas sand basins of the West is of low permeability, this is only one of several geological problems that have limited commercial development. All of these tight sands are low quality and are often highly discontinuous or lenticular.[33] As formation permeability drops, recovery efficiency becomes highly sensitive to even small permeability changes. When low permeability combines with lenticular formations an additional problem arises. The principal commercial successes in tight formation have been in the relatively continuous blanket type sands, but most of the tight gas sands are notably discontinuous.[34] Massive hydraulic fracturing has been successful in lenticular formations only where the individual lenses are large relative to the normal well drainage area or where the individual lenses are developed in conjunction with vertically adjacent blanket formations.[35] In addition to low permeability and frequent lenticularity, the gas containing sands of the tight basins are of low quality relative to conventional gas formations. Even though the sands can range in thickness from 2,000 to 5,000 feet, the portions from which gas can be extracted may be only a few hundred feet thick and may also be dispersed in relatively thin (10 feet or less) zones interbedded with clays and shales.[36]

Also, the gas sand segments often contain high levels of formation water that impede gas flow in the fracture system. Since porosities are low (usually between 5 and 15 percent), this combined with relatively high formation water saturations (40 to 70 percent) reduces the gas filled porosity in the sands to levels from less than 3 to seldom over 9 percent.[37] Finally, the gas zones in tight basins often contain clays that swell when contacted by drilling or fracturing fluids, unless the fluids contain chemicals designed to inhibit such swelling.

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[31] Four Categories of Gas Get Market Pricing. Oil & Gas Journal, Nov. 5, 1979, p. 37.
[32] Ibid.
[33] Kuuskraa, op. cit., p. 48.
[34] Ibid. p. 49.
[35] Ibid.
[36] Ibid.
[37] Ibid.

Thus, geology and reservoir characteristics impose limits on the amount of commercial gas that can be recovered from tight sands. To further utilize this difficult resource, it is necessary that fracturing technology move toward a method of stimulation of all gas zone intervals exposed to the well bore, by using multiple fractures engineered from the same well. Also, such fractures should intersect, in lenticular formations, sand lenses not initially in contact with the well bore. Fracturing technology should attempt to maintain an effectively propped fracture, thus providing an adequate passage for the movement of gas to the well.

Reservoir stimulation and the production history of Devonian shale gas reservoirs indicates that the gas which is recovered is the gas which occurs in well-connected fracture porosity.[38] The estimated recovery efficiency is quite high (45 to 60 percent for shot wells and 55 to 65 percent for fractured wells after 30 years of production). The higher free market prices will probably promote infill drilling in developed areas to exploit reservoir volumes that have only been partially drained due to the low permeability of the fine fracture network.

To reach higher production rates and increased ultimate recovery, a research and development effort will be needed to improve the understanding of the locations in a basin where the Devonian shale is intensely fractured and thus a good gas producing prospect. Also, the application of dual well completion technology to produce marginal shales along with other gas bearing sands would be significant as would increasing the vertical efficiency of well stimulation techniques.[39]

In general, the Appalachian basin coal seams may be too thin and contain too little gas to support commercial recovery.[40] A better target for recovering gas from coal may be the thick, bituminous coal seams of Colorado and the other western States.[41] The evaluation of potential commercial production of gas from coal seams should include ways in which the recovery costs can be considered to enhance safety and productivity as well as to produce saleable gas. Evaluations should, in addition, consider methane productivity from deep, currently unminable, coal seams having highly favorable geological characteristics for the recovery of gas.

Several technological problems must be solved before geopressured gas is commercialized. This includes overcoming any production problems that might constrain high production rates. The poorly consolidated nature of the reservoir sands may significantly reduce permeability near the well bore as the pressure is lowered during production. The two main environmental problems associated with the production of gas from geopressured deposits concern the proper disposal of the large volumes of brine which are expected to be produced along with the gas, and the possible land subsidence which may occur upon the withdrawal of large volumes of underground fluids. Slight subsidence, which would scarely be noticed in many areas, could be serious in the low lying regions of the Gulf Coast. The disposal of produced brine into the same formations from which it came could solve this problem, but the cost of

[38] Ibid., p. 51.
[39] Ibid.
[40] Ibid., pp. 51-52.
[41] Ibid., p. 52.

deep wells would seriously reduce the economic attractiveness of geopressured gas development.[42]

It has been estimated that, to maintain current levels of oil and gas production, oil and gas capital requirements would have to rise from a current $20 billion annually (1978) to $142 billion in 1990 (current dollars). This is estimated to be 21 percent of the Nation's total investment in 1990, as compared to only 9 percent last year. The oil and gas industry is thought unlikely to capture such a high proportion of the total business investment.[43]

IV. Potential Contribution to Future U.S. Energy Supplies

It is very difficult to project the potential contribution from resources which, in some cases, are not now commercial.

However, when four categories of gas (deep gas, geopressured gas, coal seam gas, and Devonian shale gas) were released from price controls to be sold at the market price, the Administration estimated that this action would lead to the production of an additional 1 to 2 trillion cubic feet of gas, but no time frame was given for this estimate.[44]

In the case of tight gas sands, about 1 trillion cubic feet of gas per year is currently being produced, from a resource base estimated to be between 600 and 1,200 trillion cubic feet. Of this resource base, 50 to 350 trillion cubic feet ultimately may be recoverable with improved technology.[45] It has been estimated that by 1990 annual production from tight gas sands may total between 2 and 8 trillion cubic feet.[46] If an ultimate recovery of only 50 trillion cubic feet is accomplished, however, it is doubtful that recovery will exceed 5 trillion cubic feet (reserves/production ratio of 10/1) during any one year. Production beyond 1990 could continue to increase, if between 2 and 4 trillion cubic feet were achieved by 1990, but would probably level off or decrease if the higher production figures (4 to 8 trillion cubic feet) were reached early.[47] This is because if the higher production were achieved before 1990, the large amount of recovered gas would be projected to exhaust the better tight sand deposits, leaving the only poorer deposits for the time period after 1990, and, hence resulting in a decline in production.

Yearly Devonian shale gas production is estimated at about 100 billion cubic feet. This is produced from a reserve estimated to range between 2.56 and 3.38 trillion cubic feet, with a recoverable resource base estimated at between 10 and 560 trillion cubic feet.[48]

Gas production from Devonian shale in 1990 has been estimated to range between 0.1 and 0.6 trillion cubic feet.[49] Production after 1990 is projected to decline as the better deposits become exhausted.[50] However, if the higher recoverable resource estimates prove correct, this decline will probably not occur.

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[42] Riva, Joseph P., op. cit., pp. 25–27.
[43] An Energy Viewpoint From Bankers Trust. Hon. John W. Wydler, Congressional Record, Nov. 8, 1979, p. E5519.
[44] Four Categories of Gas Get Market Pricing., op. cit.
[45] Energy Research Reports. Mar. 19, 1979.
[46] Kuuskraa, op. cit. p. 50.
[47] Ibid.
[48] Energy Research Reports, op. cit.
[49] Kuuskraa, op. cit. p. 52.
[50] Ibid.

There is currently no commercial production of natural gas from coal seams. The amount of gas contained in coal seams in the United States has been estimated to be at least 300 trillion cubic feet, a figure that could be extended with additional information. Another estimate places a range of 16 to 500 trillion cubic feet as the potential coal seam gas resource which may become recoverable.[51] Gas production from coal seams has been estimated to range from 0.04 to 0.05 trillion cubic feet in 1990 and to continue to increase in volume to from 0.05 to 0.08 trillion cubic feet per year by 2000.[52]

At the present time there is no commercial production of natural gas from geopressured deposits. The Federal Government has had an active research and development program concerning the geopressured resource since 1975. One of the objectives of this program is to produce geopressured gas. The DOE anticipated that in 1985 the amount of commercial geopressured gas produced will range from 0 to 20 billion cubic feet. The DOE projection for 2000 is between 2 and 4 trillion cubic feet.[53] It is difficult to estimate whether geopressured gas will ever make a significant contribution to domestic energy supply. It would take a geopressured reservoir the size of Prudhoe Bay to contain 2 trillion cubic feet of gas, of which only 0.1 trillion cubic feet might be recovered.[54] However, if the amount of dissolved and immobile gas in some geopressured reservoirs is sufficiently large, the possibility exists that it may be produced with reduced amounts of associated brine. If this proves to be the case, commercial gas production from smaller geopressured deposits may be possible.

[51] Energy Research Reports., op. cit.
[52] Kuuskraa, op. cit. p. 51.
[53] DiBona, Bennie G. Overview of the Federal Geopressured-Geothermal Energy Resource Development Program. Gas Supply Review, American Gas Association, October 1978, p. 9.
[54] Doscher, T. M., Osborne, S. W. Rhee, T. Wilson, and D. Cox. Methane From Geopressured Aquifers Studies. Oil & Gas Journal, Apr. 9, 1979, p. 178.

ORGANIC CONVERSION TECHNOLOGIES

ENERGY FROM MUNICIPAL SOLID WASTES *

I. SURVEY OF THE CURRENT SITUATION

A. Description of the Technology[1]

"Energy from Solid Wastes" (ESW) processes recapture and utilize the organic or combustible portions of solid wastes. Many systems use mechanical means to separate the organic or combustible portions of solid wastes from materials that cannot be burned or used for energy purposes. The general process involves homogenization of the waste materials by size reduction (e.g., shredding or crushing) and separation by size, weight, shape, density, and other physical properties. A typical processing system would utilize shredding for size reduction of raw refuse, followed by some form of air classification to further separate the combustible materials from the noncombustible materials. The combustible portion is called refuse-derived fuel (RDF). Such fuel can be mixed with coal and derivates of this fuel can be mixed with oil and burned in a conventional utility boiler. Some plants do not produce RDF, but simply burn the wastes directly or convert the combustible portions of solid wastes into gaseous or liquid products. Some ESW plants also recover glass and metals from solid wastes.

A typical plant processing 1,000 tons of wastes daily would be designed to:

(*a*) Produce upwards of two trillion Btus of low-sulfur fuel per year, the equivalent of roughly 300,000 barrels of oil;

(*b*) Recover in a year as much as 20,000 tons of ferrous metals, 1,200 tons of aluminum and other non-ferrous metals, and 15,000 tons of glass for use by industry in various manufacturing processes; and

(*c*) Reduce the amount of material requiring land disposal from over 300,000 tons per year of mixed wastes (including organic wastes and metals) to about 60,000 tons per year of relatively inert material.[2]

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* Prepared by Paul F. Rothberg, specialist in physical sciences.

[1] This chapter focuses on the large-scale production of fuels from municipal solid wastes. The production of fuels from forestry or agricultural wastes is considered in the chapters dealing with alcohol fuels.

[2] Statement by Barker, James L. in U.S. Congress. House. Committee on Science and Technology and Committee on Interstate and Foreign Commerce. Subcommittee on Energy Develop-

B. *Known Resources and Reserves*

Recent estimates indicate that the amount of municipal solid wastes generated in the United States each year totals about 130–200 million tons. These wastes, plus approximately 14 million tons of sewage solids, are resources potentially available for ESW systems.[3] Thus, the theoretical energy potential of ESW processes is roughly 200 million barrels of oil each year, if one assumes that roughly one ton of waste can be converted to one barrel of oil.[4] However, much of the resource base is widely dispersed over large geographic areas and cannot be economically collected and transported to a centrally-located facility. Therefore, ESW plants are generally constructed in areas where a large volume—at least several hundred tons—of wastes can be economically supplied each day.

C. *Current Contribution to U.S. Energy Supplies*

Less than 10,000 barrels of oil equivalent per day is currently produced at ESW plants.[5]

D. *State-of-the-Art*

The state-of-the-art of ESW process ranges from systems proven sucessful at the commerical scale to systems being tested in the laboratory.

The most technically developed processes are "waterwall furnaces" that directly burn wastes and recover steam. Over 250 of these plants now operate in Europe and Japan. About eight of these plants currently operate in the United States, although three of these were originally constructed as incinerators.[6] Because these processes have been used for many years, some manufacturers will guarantee their operating performance.

Some plants that produce RDF have been operating for years; some are nearing completion; and some are proceeding through "shake-down," the period required to solve or reduce the technical problems of process operations. Although plants producing RDF have experienced many technical problems, many advances in this technology have been made over the last ten years. Some plants have signed firm contracts with buyers willing to pay substantial prices for RDF products. If the plants prove capable of delivery RDF and recovered products on a reliable basis, the economic feasibility of this process would be improved, i.e., as technical reliability improves so does economic feasibility.

Processes that gasify or liquefy wastes are in the early stages of innovation and still require additional research, development, and

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ment and Applications and the Subcommittee on Transportation and Commerce, Waste-to-Energy. 96th Congress, 1st session (Washington, Government Printing Office, 1979), pp. 253-274.

[3] Ibid.

[4] Thermal efficiencies of different processes vary. Some processes may yield more than one barrel of oil equivalent per ton of waste processed, some may yield less. For purposes of calculation, the conversion factor of one ton of waste being roughly equivalent to one barrel of oil is used.

[5] Production level is calculated from data on production capacity of active ESW projects as compiled by: National Center for Resource Recovery. "Resource Recovery Activities" March 1980, 7 p. Calculation assumes that one ton of processed municipal solid wastes yields roughly one barrel of oil equivalent.

[6] U.S. Department of Energy. Commericalization Strategy Report for Energy from Urban Wastes. (Draft) 1978, p. 5.

demonstration.[7] Manufacturers are generally reluctant to underwrite the performance of these systems.

E. Current Research and Development

The DOE is authorized to support research, development, and demonstration of ESW processes, as well as to offer financial incentives to communities seeking to construct commerical demonstration facilities. One of DOE's objectives is to conduct research and development to provide technological options for planners so they may select an ESW system applicable to specific local conditions.[8] The DOE's appropriation for its fiscal year 1979 program was $13 million and the appropriation for its fiscal year 1980 program is $13.5 million.

The private sector has invested substantial sums in commercial ESW projects; however, the total amount spent is unavailable.

II. Prospects or Requirements for Further Development

Research, development, and demonstration of ESW processes could improve the reliability of sytems components; reduce the materials problems (e.g., corrosion) of existing systems; improve the efficiency of current operations; and advance the current state of technology. New or improved processes, equipment, and designs could result from an intensive Federal/industry program designed to advance ESW systems.[9]

Although research, development, and demonstration activities are important, commercialization activities could foster the near-term contribution of ESW systems to U.S. energy supplies. About sixty commercial or large scale systems are now either in the final planning, construction, or operational phase. Successful commercialization of these plants might convince industry and community groups, as well as state and local governments, to sponsor ESW projects. Current projects could also provide useful information to other groups planning future ESW plants.

III. Potential Obstacles to R. & D. or Technology Implementation [10]

Several significant problems currently impede rapid widespread commercialization of ESW systems. First, the process of commercializing an ESW project is time consuming and expensive and involves a variety of participants, including State and local governments faced with growing waste disposal problems, industry groups owning proprietary ESW processes, trash collection agencies and citizens wanting to dispose of their trash, and companies seeking to purchase recycled materials. If all of these groups cooperate, the chance of a project succeeding is greatly increased. Project particpants face many risks and uncertanties, including financing problems, legal constraints, and sometimes public opposition to a proj-

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[7] Barker, James L., op cit., p. 7.

[8] From Annual DOE Budget Submittal to Congress for fiscal year 1979.

[9] For additional information on research and development needs see: Unpublished testimony of Audrey Buyrn before Subcommittee on Energy Development and Applications of the House Committee on the House Committee on Science and Technology, March 11, 1980.

[10] This section is primarily based on the testimony of Barker, James L., op. cit., pp. 253–74.

ect. Experience to date suggests that the time required to advance a project from the concept stage to full-scale operations is often in excess of five years and expenditures can total more than $100 million.[11]

Second, economic conditions in local energy markets can often deter the construction of a project. The economic feasibility of ESW plants is generally least promising where waste disposal costs are low and where low-sulfur coal or other fuels are abundant and cheap. The economic feasibility of ESW plants is generally most promising in areas where fuel and waste disposal costs are high.

Third, sponsors of ESW projects face major technical uncertainties that can discourage ventures at the early planning stages. Although many ESW systems are currently under construction, there is not much operating experience on which to judge these projects. Thus, an accurate assessment of long-term performance and reliability of these systems is unavailable to prospective buyers and users.

Fourth, the ESW industry faces market and institutional constraints. For a variety of reasons, many industrial companies and public utilities are reluctant to depend on ESW plants as a major source of their fuel needs. Some ESW frequently break down or do not operate at full capacity, and thus cannot be counted on for supplying a secure, long-term source of fuel. Because the output level of these plants is uncertain, the demand for ESW products is substantially reduced. In addition, the market for some products, such as steam, is limited by physical constraints: steam cannot be stored for long periods or transported economically long distances.

Finally, the ESW industry is faced with the problem of dealing with many cautious municipalities that are reluctant to participate in ESW projects. Such institutions tend to avoid involvement in an innovative, risky, and expensive venture such as an ESW plant. Another institutional problem is the difficulty of establishing a regional system for waste collection and processing. In many cases, several communities must pool their solid wastes in order to meet the input requirements of an ESW plant.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

As previously indicated, the commercialization of ESW plants is a rather lengthy and difficult process that involves many uncertainties. The current and anticipated level of industrial activity indicates the ESW plants could produce about 20,000 to 85,000 barrels of oil equivalent per day by 1990.[12] The lower estimate is based on the assumption that only about one half of the design capacity of the plants that are built, operating, in shakedown, under construction, or in the final contract-signing stages is reached by 1990. The higher estimate assumes that all of these plants reach design capacity and an additional 45,000 barrels of daily capacity is obtained from plants that are in the advanced

[11] For a plant processing about 2,000 tons per day of municipal solid wastes.
[12] Current and anticipated level of industrial activity is based on data from: National Center for Resource Recovery, op. cit.

planning stages, have issued requests for proposals, or are negotiating with bidders/contractors.

B. Contribution by 2000 or Beyond

At the current stage of industrial development, estimates of the expected contribution of ESW plants beyond 1990 are highly speculative. Factors that are likely to influence the long-term contribution of ESW plants include:

(*a*) The degree of technical success experienced by plants currently planned or underway;

(*b*) The effect of Federal and State policies on this industry;

(*c*) The price and availability of imported oil and domestic gas;

(*d*) The amount of the tipping fee, i.e., the fee charged to dump solid wastes, received by ESW plants; and

(*e*) The need to find ways to reduce the Nation's solid waste disposal problems.[13]

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[13] ESW plants reduce the volume of solid waste requiring disposal.

ETHANOL *

I. Survey of Current Situation

A. Description of Technology

Grain (or other agricultural material) can be distilled in a fermentation plant to produce ethyl alcohol (ethanol). The alcohol can then be used to operate automobile engines, either by itself or in a 10 percent blend with gasoline. The alcohol-gasoline blend has become known as "gasohol." The supply, on a nationwide scale, is limited; to produce a 10 percent blend of "gasohol" nationwide, 40 percent of the grain harvest would have to be used (infra.). Cattle feed and carbon dioxide would be produced as byproducts in the distillation process.

B. Known Resources and Reserves

The supply situation with regard to ethanol from grain, as compared to U.S. automotive requirements, may be summarized as follows: Nearly 110 billion gallons of gasoline are used by automobiles in the United States annually to meet national needs. If alcohol were used in a 10 percent alcohol/90 percent gasoline blend, 11 billion gallons of alcohol would be required. At 2.55 gallons per bushel, 4.3 billion bushels of grain are needed for this amount of alcohol. The total U.S. grain harvest is approximately 10 billion bushels. Substituting alcohol for 10 percent of the gasoline currently used, therefore, would require over 40 percent of the U.S. grain harvest. Putting it another way, all our grain harvest, if burned as pure alcohol fuel, would only replace about 25 percent of our annual gasoline requirements. Thus, the supply problem would make use of grain-derived ethanol impractical as a general replacement for gasoline, although lesser and specialized limited uses may be feasible.

The supply problem would still exist even if idle lands were to be used for fuel production purposes. In 1979, about 22 million acres were idled under supply control programs. These acres might be expected to produce about 900 million bushels of grain, which could be converted to about 2.3 billion gallons of alcohol. Therefore, using all the available surplus land to produce alcohol fuel would only add about another 2 percent of the national fuel supply to the 25 percent potentially available from all of the existing grain harvest.

The capability for obtaining alcohol fuels from sugar crops (sugar cane and sugar beets) in the United States is substantially less than that for obtaining alcohol fuels from grain. The national total for sugar produced in the United States in 1977 was estimated at 6.26 million tons. The Department of Agriculture estimates that 164 gallons of alcohol could be obtained per ton of sugar produced. Therefore, if the entire sugar crop were used for this purpose, 1,027

* Prepared by Migdon R. Segal, analyst in energy technology.

million, or roughly 1 billion gallons of alcohol would be produced. This would only be enough to fill 1 percent of the national automotive need or 10 percent of the national requirement for a 10 percent blend.

If cellulose can be converted to ethanol, it would then become feasible to produce ethanol from wood, from agricultural byproducts such as cornstalks and the like, and from municipal solid waste (MSW). This would greatly increase the available supply of feedstocks from which ethanol can be derived. One method for converting the cellulose to ethanol involves converting the cellulose to glucose, using an enzymatic hydrolysis process. The glucose is then fermented to produce alcohol. This and similar processes have been demonstrated in the laboratory, but not yet on a large scale. Alcohol fuel advocates claim that a "breakthrough" in this important field of research may be imminent.

C. Current Contribution to U.S. Energy Supplies

Gasohol blends containing 10 percent ethanol and 90 percent gasoline are marketed at hundreds of gasoline stations in the United States. The amount of alcohol fuel being produced nationally in late 1980 was approximately 120 million gallons per year, which is only 1.2 percent of the 10 billion gallons that would be necessary for a 10 percent gasohol blend nationwide.

D. State-of-the-Art

The technology for making alcohol from grain and other agricultural crops is relatively unsophisticated, and alcohol "stills" have been built for this purpose for perhaps thousands of years. However, making alcohol from agricultural crops in an energy-efficient way requires more advanced technology. At present, the alcohol for "gasohol" now on sale is made in alcoholic beverage distilleries converted for this purpose. These facilities are old and were not designed with energy efficiency in mind. Questions have been raised as to whether the net energy balance for such facilities would be negative, i.e. would more energy be consumed than is available from the alcohol once produced?

The Department of Energy (DOE), addressing this question in its "Alcohol Fuels Policy Review," states that new ethanol production plants could be built with much greater efficiencies than existing plants, and the energy balance for a modern facility would be positive to a slight degree, i.e., more energy would be available in the alcohol fuel than was used to produce that fuel.[1] This is the most positive statement made thus far by a government agency with respect to the energy balance question.

E. Current Research and Development

1. UNITED STATES

Federal funding for research and development for alcohol fuels (including both ethanol and methanol) for fiscal year 1980 is an

[1] "The Report of the Alcohol Fuels Policy Review," U.S. Department of Energy, Assistant Secretary for Policy Evaluation, June 1979, p. 15.

estimated $18.45 million, of which $15.2 million is in the DOE budget, and $3.25 million in the Department of Agriculture budget. For fiscal year 1981, an estimated $24.9 million was requested, $19.0 under DOE and $5.9 under USDA. Most of this funding is for fuels from biomass. (This includes funding for both ethanol and methanol.)

Commercialization of ethanol as a fuel, in the "gasohol" blend of 90 percent gasoline to 10 percent alcohol, is well under way. Commercialization is taking place in the private sector of the economy, without direct governmental involvement. However, the National Energy Act motor fuel excise tax exemption, which is worth 4 cents per gallon of blend or 40 cents per gallon of alcohol used in a ten percent blend, is widely believed to have been a major stimulus to the growth of a "gasohol" industry. The expiration date of this exemption has been extended from 1984 to 1992 in Public Law 96–223, the Crude Oil Windfall Profit Tax Act of 1980, which was signed into law in April 1980. Similar tax exemptions also exist in many of the States in regard to State gasoline taxes. Gasohol is now being sold in more than a thousand gasoline stations around the United States.

2. BRAZIL

Brazil has taken the lead in alcohol fuels development, and has established a national policy of replacing gasoline with "home-grown" alcohol as an automotive fuel to the maximum extent feasible. This decision was made by the Government in 1975 with the purpose of reducing the balance of payments deficit resulting from the need to import petroleum by taking advantage of Brazil's enormous land area and tropical climate to grow crops specifically for fuel purposes. Sugar cane is the current energy-producing crop, although Brazil is also experimenting with manioc, a tropical root crop, for future use.

The Brazilian Government has spent $2.5 billion on this effort, and has budgeted twice that amount for the next five years. Annual alcohol production is 4 billion liters (1.05 billion gallons) per year. The national goal of attaining a 20 percent mixture by 1980 is said to have been achieved. This amount is considered to be the maximum percentage of alcohol (ethanol) which can be used in existing automobiles without engine modification.

A new goal of increasing the alcohol production capacity to 10.7 billion liters per year (2.82 billion gallons per year) by 1985 has now been set. In keeping with the goal, the government has recently signed an agreement with Brazilian automobile manufacturers calling for the production of 250,000 alcohol-powered vehicles a year over the next five years. Another 500,000 existing automobiles are to be converted to run on pure alcohol.

3. OTHER NATIONS

In addition to the United States and Brazil, Guatemala, Austria, Switzerland, and Australia are among the nations having shown some interest in alcohol fuels.

II. Prospects or Requirements for Further Development

A. Research and Development

The technology for manufacturing ethanol is well-understood but requires improvements to make "gasohol" a practical alternative fuel. Further work would be useful on a number of questions associated with ethanol, including (but not necessarily limited to) the following:

1. ECONOMICS OF ALCOHOL FUELS MANUFACTURE

This work would be significant since it would be desirable to lower the cost of fuel alcohol from the present level of nearly $1.50 per gallon.

2. ENERGY BALANCE

The energy balance question, previously mentioned, has certainly not been closed by the DOE "Policy Review" study, and it would be important to show that the energy balance for a modern distillation plant can, in fact, be positive (or if negative, that the cost in non-petroleum fuels such as coal is small enough to justify a negative energy balance).

3. AUTOMOTIVE MILEAGE

As yet no definitive conclusion has been reached on the question of whether the automotive mileage achieved with gasohol, or with pure ethanol, is less than or greater than that achievable with gasoline. Ethanol has only two-thirds the energy value per gallon than does gasoline, but gasohol proponents claim that it burns more efficiently and thus compensates for its lower inherent energy value as compared to gasoline. This question must be dealt with for ethanol to be seriously evaluated as an automotive fuel.[2]

4. FEEDSTOCKS

Most alcohol is currently made from corn. A variety of other agricultural crops have been suggested as sources of fuel alcohol, including sugar cane, wheat, and beet sorghum. In addition, work is now underway on the breakdown of cellulose to form ethanol, a process which would make it feasible to produce ethanol from wood, from municipal solid wastes (MSW), and from agricultural byproducts such as cornstalks. A practical cellulose-to-ethanol process would vastly increase the potential supply of ethanol feedstocks, and therefore make ethanol a more practical candidate for large-scale use as a fuel.

5. ENVIRONMENTAL POLLUTION

No definitive conclusions have yet been reached as to whether alcohol fuels, alone or in a "gasohol" blend, are more or less polluting than gasoline. According to the Department of Energy, there is no significant advantage or disadvantage for these fuels as opposed to gasoline. As emissions of CO and unburned hydrocarbons are decreased, NO_X emissions may be either increased or

[2] "Alcohol Fuels Policy Review," op. cit., p. 17.

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decreased, and aldehyde and evaporative emissions are increased.[3] The State of California has concluded that gasohol tends to increase air pollution, because of the increase in evaporative emissions from the carburetor after the vehicle has stopped.[4] The question appears to need further study.

B. Demonstration

Demonstration projects would presumably be required in the areas discussed under "Research and Development," above, i.e., economics, energy balance, automotive mileage, and choice of feedstocks. With regard to feedstocks, the Agriculture Department was authorized by the Congress (under Public Law 95-113) to build four pilot plants, at up to $15 million each, to investigate various concepts for obtaining energy from agricultural or forest products. The four pilot plants have now tentatively been awarded. Two of them involve alcohol fuels. They are:

(*a*) A plant to produce alcohol from bagasse (sugar cane wastes), to be built in Florida by Suchem, and Biomass Corporation, subsidiaries, respectively, of U.S. Sugar and Savannah Foods.

(*b*) A plant to produce ethanol from grain sorghum, sweet sorghum, and sugar cane molasses, to be built at Santa Rosa, Texas by Midwest Solvents, Inc., of Kansas.

Demonstration projects dealing with economics of manufacture, energy balance, and automotive mileage have not yet been planned, since such projects were not specifically authorized by law. However, such projects would be highly useful to alchohol fuels development.

C. Commercialization

1. CAPITAL

In DOE's "Alcohol Fuels Program Plan," [5] it is stated that ten 30 million gallons-per-year fermentation plants could be built by 1985 at a cumulative investment of nearly $500 million. If this estimate is accurate, than each million gallons per year of ethanol plant capacity would cost roughly $1.67 million. Enough ethanol plant capacity for a 10 percent "gasohol" mixture nationwide (assuming the raw materials could be found to make 10 billion gallons of ethanol), would then cost approximately $17 billion.

2. TIME

The unique appeal of the 10 percent "gasohol" blend of ethanol and gasoline is that it is available today, and DOE considers it the only alternative fuel likely to be available in any quantity before 1985.

Ethanol fuel production was estimated by DOE (in June 1979) to increase from its currrent level of 60 million gallons per year, to 300 million gallons per year by 1982, and to 500 to 600 million

[3] "Report of the Alcohol Fuels Policy Review," op. cit., p. 108.
[4] "Controlled Use of Gasohol in State Urged," Los Angeles Times, Mar. 27, 1980, p. 1.
[5] U.S. Department of Energy. Office of the Under Secretary. Task Force on Alcohol Fuels. "Alcohol Fuels Program Plan." March 1978, pp. 2-7.

gallons per year by 1985. Other projections are more optimistic. In connection with the January 1980 embargo on the sale of grain to the Soviet Union, the Carter Administration announced its intention to achieve a goal of 500 million gallons per year of ethanol production capacity by the end of 1981. This is an ambitious target, and there is some question as to whether it can, in fact, be reached.[6] The National Gasohol Commission states that goals of 5 percent of United States gasoline needs by 1985, and 10 percent by 1990, are realistic. These would amount to 5 billion and 10 billion gallons, respectively. Such projections relating to the distant future, by their nature, may not be highly reliable, since they depend on such variables as plant construction, feedstock availability (such as a practical cellulose conversion project), the relative costs of competing fuels, and political factors which might influence national energy goals.

3. MANPOWER

The question of manpower requirements of an alochol fuels program can be subdivided into two phases: construction and production. For the construction phase, the manpower requirements of a $17 billion construction program would be sizable, though specific estimates are lacking. For production, the impact of alcohol production is almost certain to be positive (i.e. to increase employment as compared with obtaining equivalent energy from gasoline), but also very likely to be small. Manpower requirements for gasoline refineries and alcohol distilleries are roughly equal. Neither facility is labor-intensive, and a reduction in gasoline demand could amount to a shift of plant employment from gasoline to alcohol.

4. MATERIAL NEEDS

If ethanol is to be produced from grain, there are roughly 2.5 gallons of alcohol available per bushel of grain. Therefore, the 60 million gallons of fuel alcohol estimated to be produced this year requires 24 million bushels of grain. The 300 million gallons projected by DOE to be produced by 1982 would require 120 million bushels, and the 500 to 600 million gallons projected by DOE for 1985 would require 200 to 240 million bushels. These amounts are well within the range which could be provided by the U.S. grain harvest, which is on the order of 10 billion bushels per year.

If it were desirable to attain a 10 percent alcohol mixture nationwide exclusively with grain-derived ethanol, 4.3 billion bushels of grain would be required. This would be over 40 percent of the grain harvest, and may not be feasible. Cellulose conversion would, however, make ample supplies available from farm wastes, municipal wastes, and wood.

The DOE has stated that sufficient surplus and waste raw materials are available to meet any realistic projected level of alcohol production through the mid 1980's. Growing of crops specifically for this purpose, therefore, does not appear to DOE to be necessary as a national policy, although individual farmers, of course, have the option of choosing to grow crops for alcohol fuel if they so desire.

[6] Engineering News-Record, March 1980, p. 7.

5. ENERGY EXPENDITURE

As previously stated, the question of whether the energy balance for alcohol fuel production is positive or negative, i.e. whether more energy is consumed in the production process than is available from the fuel once produced, is complex and difficult, depending to some extent on the assumptions made in the energy balance calculation. Some of the varied assumptions that go into this calculation are as follows.

Opponents of "gasohol" claim that the energy required to produce it (growing the crops, operating the fermentation plants, etc.) is greater than the energy obtainable from the alcohol once produced. Gasohol advocates seem to concede the point if the energy from the alcohol alone is considered, but contend that the additional energy obtainable by burning the stalks and other grain residues would make the "energy balance" positive. The opponents then counter that, if these products are to be burned rather than left on the land, additional fertilizer would have to be purchased so as not to deplete the soil, which would make the energy balance negative once again. The DOE experts now believe the energy balance for ethanol will be positive if modern equipment is used.[7]

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

Ethanol is already in use as automotive fuel, and there appear to be no technical obstacles to its further use. There is, however, a question as to the availability of sufficient feedstocks to allow for a large-scale "gasohol" program. The supply problem would be resolved if it becomes feasible to make ethanol from cellulosic materials. This would make it possible to use wood, solid wastes, and agricultural byproducts (e.g. cornstalks) as feedstocks for ethanol fuel production. Cellulose to ethanol conversion technology, such as the enzymatic hydrolysis process mentioned previously, is under development, and is needed if ethanol is to make a major contribution to the Nation's energy future.

B. Economic

Possible obstacles to the implementation of a large-scale ethanol program in the economic category include: (*a*) cost of alcohol fuels, (*b*) energy balance, and (*c*) automotive mileage.

Regarding cost, ethanol currently sells for $1.20 to $1.60 per gallon. The DOE contends that it could be produced for less than $1.00 per gallon and sold for around $1.00 per gallon, using advanced available technology. One important aspect of cost reduction is reducing the net feedstock costs. Since corn now sells for roughly $2.50 per bushel, and one bushel of corn yields about 2.5 gallons of ethanol, the cost of the feedstock alone is $1.00 per gallon unless the byproducts (distillers' dried grains, etc.) are recovered.

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[7] "Report of the Alcohol Fuels Policy Review," op. cit., p. 15.

Regarding energy balance, DOE now believes that ethanol can be produced to yield a net gain in liquid fuel. Existing ethanol conversion facilities were built for the production of alcoholic beverages, and were built when energy costs were lower than they are now (and were, in fact, not considered significant). A modern facility, designed with energy costs in mind, can have a positive energy balance even if it uses oil and gas for fuel. Also, these facilities can be designed to use fuels other than oil and gas. They can then be regarded as a means whereby scarce energy forms, such as coal, wood, or agricultural residues, can be converted into transportation fuel.

Regarding automotive mileage, the situation is roughly as follows: Ethanol contains roughly two-thirds the energy value in Btus per gallon that gasoline contains. If gasohol is as efficient as gasoline (in miles per Btu), the miles per gallon would be 3 percent less than the miles per gallon with gasoline. However, the number of miles per gallon cars actually achieve depends on many factors other than the Btu value alone. The evidence on gasohol mileage to date is highly varied, as the effect of the lower Btu value is to some degree offset by the change in combustion characteristics and the cleaner burning qualities of alcohol. Limited scientific testing thus far shows that gasohol appears to have increased miles per Btu, but still decreased miles per gallon, as compared with gasoline. These results, however, will vary from car to car and from driver to driver.

C. Environmental

While gasohol advocates claim that alcohol fuels are less polluting than gasoline, these claims have yet to be proven by an impartial source. Data, thus far, are not totally conclusive, but DOE sees no significant advantage or disadvantage for gasohol as opposed to gasoline. The NO_x (nitrogen oxide) emissions may be either increased or decreased by using alcohol fuels, while CO (carbon monoxide) and unburned hydrocarbons are decreased, and evaporative emissions are increased. There is a possibility that unburned alcohol and aldehydes might be a new pollution problem unique to alcohol combustion.

D. Social

N/A.

E. Political

At present, political factors work in favor of farm-derived ethanol as a fuel and not against it. "Gasohol" has become a politically popular movement, based primarily on support by Midwest farmers seeking improved U.S. fuel security along with better markets and higher prices for their grain crops. This movement has helped to stimulate Congressional and Executive Branch interest in ethanol fuel.

A major political factor working in favor of gasohol is its appeal as "America's homegrown fuel." With the current surge of popular feeling against OPEC dependence, the political appeal of a domestically produced automotive fuel needs no further comment.

F. Regulatory

Ethanol, of course, is well known as the source of intoxicating beverages. As such, its manufacture is tightly regulated by the

Department of the Treasury's Bureau of Alcohol, Tobacco, and Firearms (BATF). The taxation of beverage alcohol returns $5.5 billion per year in revenue to the Federal Government, and producing beverage alcohol without obtaining the appropriate permits and paying the associated taxes is a felony.

The possibility of large quantities of ethyl alcohol being produced for use as an automotive fuel therefore has understandably aroused the concern of the BATF. They do not wish to put unnecessary obstacles in the way of developing a possible energy source; but on the other hand, they are concerned that a twenty-fold increase in the production of alcohol (which would be necessary in order to have a 10 percent gasohol blend nationwide) would increase the possibilities for illegal diversion of alcohol to make untaxed "moonshine" liquor.

This dilemma has been ameliorated by the passage of Public Law 96–223, the Crude Oil Windfall Profit Tax Act of 1980, in April 1980. Provisions of this legislation simplify the BATF regulations as they apply to alcohol fuels production, easing particularly the burden on small, "on-farm" producers, while still maintaining BATF's overall jurisdiction over alcohol manufacture.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

As stated previously, in June 1979 DOE estimated that by 1985 ethanol production for fuel purposes will reach 500 to 600 million gallons per year. However, the Administration in early 1980 established a goal of 500 million gallons per year by 1981. Projections beyond 1985 are more difficult, depending on many variables difficult to forecast. A reasonable projection for 1990 might be the DOE estimate of 7.2 billion gallons per year, which is called the "projected ethanol production from maximum available food processing wastes, grains and sugar crops." This projection implies a vigorous alcohol fuel development program, making use of crops such as sweet sorghum and sugar cane as well as the grain crops used to make fuel alcohol today. This estimate, however, does not include the additional ethanol which might be obtained from wood, agricultural residues, and MSW (assuming that conversion of cellulose to ethanol is feasible by 1990). With these products included, DOE estimates 41.2 billion gallons of fuel ethanol could be produced by 1990.

The National Gasohol Commission, which is funded by State governments end others interested in promoting the development of agriculturally-based ethyl alcohol as a fuel, estimates that 5 billion gallons of ethanol derived from farm crops could be prouced by 1985, and 10 billion gallons by 1990. These estimates are higher than those of DOE, especially for 1985.

B. Contribution by 2000 or Beyond

For projections to the year 2000 and beyond, it appears more reasonable to assume that cellulosic materials would be converted to ethanol. Using that assumption, DOE has estimated that 54.0 billion gallons of fuel ethanol could be produced per year by 2000.

This would be enough for about half of the nation's automotive fuel needs, assuming that the demand for automotive fuels remains the same in 2000 as it is now. The 54 billion gallons would include 25.8 billion gallons derived from wood, 13.1 billion from agricultural residues, 2.9 billion from MSW, and 12.2 billion from agricultural crops and food processing wastes.[8]

Estimates from other sources for projections for ethanol production beyond the year 2000 are not available.

[8] "Alcohol Fuels Policy Review", op. cit., p. 55.

METHANOL *

I. Survey of Current Situation

A. Description of Technology

Coal, wood, or urban wastes can be subjected to chemical reactions which produce methyl alcohol (methanol). The alcohol can then be used to operate automobile engines, either by itself or in a blend with gasoline. Blends of either ethanol or methanol with gasoline have become popularly known as "gasohol." Assuming that the goal is to produce a 10 percent methanol to gasoline blend, coal or wood could provide an ample supply of methanol. Approximately 10 billion gallons of methanol would be required; this could be obtained from 38 million tons of coal (about 6 percent of our present coal output), from 21.7 million acres of forest land (about 4 percent of the national forest acreage), or from 180 million tons of urban wastes (about the national total). The distillation of coal to produce methanol also produces useful byproducts such as methane, benzene, and toluene. Useful byproducts obtainable by distillation of wood or urban wastes to produce methanol are unknown at present.

B. Known Resources and Reserves

The supply situation with regard to methanol from coal, wood, or urban wastes, as compared to the U.S. automotive fuel requirements, may be summarized as follows:

The United States consumes about 100 billion gallons of gasoline per year. Assuming that 10 percent methanol were to be used, and that this consumption rate remained constant, then 10 billion gallons of methanol would be required. This is about 60 billion pounds, or 30 million tons of methanol that would be required. The efficiency of converting coal to methanol has been estimated by the Department of Energy (DOE) at 79 percent.[1] Therefore, in order to obtain 30 million tons of methanol, 38 million tons of coal per year, or 6 percent of our present coal output would have to be converted to methanol to obtain enough to provide a 10 percent mixture for all American automotive needs. This would involve expanding methanol production in this country by a factor of ten, which would require a considerable effort in terms of plant construction.

Estimates for wood are more speculative than for coal, since wood-to-methanol conversion plants have not yet been built, and the amount of wood that can be produced per acre per year is a highly controversial figure. An estimate by DOE has a wood-to-methanol plant processing about 1,500 tons per day of wood, and producing 50 million gallons per year of methanol.[2] Methanol weighs 6.59 pounds per gallon. Converting these figures to pounds per year, one arrives at the estimate that, on a weight basis, about

* Prepared by Migdon Segal, analyst in energy technology.

[1] Telephone conversation with Mr. David Garrett, Office of Fossil Energy, DOE.

[2] Telephone conversation with Mr. John Pulice, DOE.

30 percent of the wood consumed is converted to methanol. If one then assumes that an acre of forest land can produce 5 tons of wood per year (a DOE estimate, assuming good forest management techniques are used), then 460 gallons of methanol could be produced per acre of forest land. In order to obtain 10 billion gallons, then, roughly 22 million acres of forest would be required per year. This is about 4 percent of the total national forest acreage.

It would appear, then, that the demand for enough methanol to provide a 10 percent blend with automotive gasoline could be met from U.S. forest resources. Such a large-scale use of wood for methanol might strain those resources, when added to the present requirements for paper, timber, and other wood products. However, proper forest management (replacing the land thus "harvested") would help to alleviate this problem.

Estimates for municipal waste are even more speculative than those for wood. A recent DOE estimates has a municipal solid waste (MSW)—to—methanol plant processing 600 tons per day of MSW, and producing 12.2 million gallons per year of methanol. This represents a ratio of about 18 percent methanol produced to MSW consumed. This also represents almost 56 gallons of methanol per ton of MSW. In order to obtain 10 billion gallons, then, about 180 million tons of MSW would be required. This is slightly less than the projected national total of 200 million tons of MSW by 1985.[3]

C. Current Contribution to U.S. Energy Supplies

Methanol is not now used as an energy source.

D. State-of-the-Art

No facility for converting coal, wood, or urban wastes to methanol now exists and methanol is not now used as an automotive fuel (the "gasohol" now on sale consists of ethanol-gasoline mixtures). Coal-to-methanol conversion plants are in the planning stages, and such plants may be ready by the 1985–90 time period.

E. Current Research and Development

Federal funding for research and development for alcohol fuels for fiscal year 1980 is an estimated $18.45 million, of which $15.2 million is funded in the Department of Energy and $3.25 million in the Department of Agriculture. For fiscal year 1981, $24.9 million was requested, of which $19.0 million was for DOE and $5.9 million for USDA. Most of this funding is for fuels for biomass. (These figures include funding for both methanol and ethanol—DOE does not separate the two in its funding estimates.)

Alcohol fuels research by DOE includes studies of feedstocks for ethanol, cellulosic feedstocks and their conversion to ethanol or methanol, coal gasification for methanol production, behavior of both ethanol and methanol in automotive use, and preliminary studies on methanol from coal. Unlike the situation with ethanol, commercialization of methanol as a fuel is not yet under way.

[3] Telephone conversation with Mr. John Pulice, DOE.

II. Prospects or Requirements for Further Development

A. Research and Development

Research and development in the following areas would be desirable if methanol is to be used as an automotive fuel on a large scale:

1. AUTOMOTIVE COMPATIBILITY

In the evaluation of alcohol fuels as potential substitutes for gasoline, there is no area as controversial as the question of how well "gasohol" could serve today's automobile fleet. One of the few points on which there is agreement is that the closer similarity between the molecular structure of ethanol and gasoline renders ethanol more compatible with existing systems than methanol. Some of the areas in which there are differing positions include operating difficulties, phase separation, materials problems and toxicity.

(a) Operating difficulties.—The latent heat of vaporization of methanol is higher than that of gasoline. Methanol is therefore slower to vaporize in a cold engine, and starting in cold weather might be a problem for this reason. This problem would not show up in tropical countries such as Brazil. However, the problem of "vapor lock," which occurs on hot days, is alleged to occur in Brazil.

(b) Phase separation.—Methanol has only limited solubility in gasoline. The methanol-gasoline mixture may therefore separate into two layers when the saturation point of the mixture is reached. The percentage of methanol at the saturation point is a variable which depends on the temperature, the type of gasoline being used, and the amount of water present (water attracts methanol and greatly encourages separation). This is basically a low-temperature phenomenon, and phase separation at 10 percent concentrations of methanol is said to occur at $-30°$ to $+30°$ F, depending on other variables. If phase separation occurs, the denser methanol would sink to the bottom of the tank and the lighter gasoline would rise to the top. The fuel feed to the engine could therefore suddenly become pure alcohol, which would probably cause the car to stall.

(c) Materials problems.—Methanol may chemically attack certain automotive components, particularly the plastic and rubber gaskets and seals used in fuel systems. The lead coating that lines gasoline tanks may also be corroded by methanol.

(d) Toxicity.—Methanol is a toxic chemical which presents definite biological hazards. If it were to be introduced into general use, measures would have to be taken to educate the public about its toxic properties. Service station attendants and others who would handle methanol as part of their daily employment would particularly be required to exercise caution.

2. METHANOL TO GASOLINE PROCESS

A catalytic process which would convert alcohol to gasoline, at an added cost of from 6 to 10 cents per gallon has been developed.[4] The process would work with either methanol or ethanol; however,

[4] Process developed by Mobil Oil Co.

emphasis has been placed on its use in connection with coal to methanol processes, believing that methanol from coal would be the most reliable source of alcohol fuel. Development of the process has progressed from the laboratory stage to plans for a pilot plant which would produce 100 barrels per day (4,200 gallons) of gasoline from methanol. If the pilot plant work is successful, the next stage would be construction of a full-scale plant (approximately 50,000 barrels per day).

The advantage of this process would be that the final product, gasoline, would be fully compatible with the existing fuel distribution system and with existing automobiles. The complications inherent in blending two separate fuels, and the possible materials and driveability problems discussed above, would be avoided. A possible disadvantage would be that the added step would reduce the overall energy efficiency of the process of obtaining a usable automotive fuel from coal.

3. ECONOMICS

The DOE projects that methanol produced from coal in the 1980s would cost 30 to 60 cents per gallon to the consumer. This would make methanol at least competitive with gasoline on a price basis (although the lower energy value per gallon of methanol, as compared to gasoline, is an important factor).

4. AUTOMOTIVE MILEAGE

Methanol has only half the energy value per gallon that gasoline has. However, automotive miles per gallon depend on the combustion characteristics of the fuel as well as the energy value, and advocates of alcohol fuel claim that it burns more efficiently, thus compensating for its lower inherent energy value. This question, along with the economic question above, are critical to a proper understanding and evaluation of methanol as an automotive fuel.

5. FEEDSTOCKS

Methanol could be produced from coal, wood, or urban wastes. Production of methanol from coal may be most promising, since the Nation's coal supplies are ample and the technology for this process is well developed. However, advocates of renewable sources for energy can be expected to press for wood and urban wastes as sources of methanol. Research is needed on the feasibility and the problems which might be associated with obtaining methanol from these renewable sources.

B. Demonstration

Demonstration projects would presumably be required in the areas discussed under "Research and Development" above, i.e. automotive compatibility, the methanol to gasoline process, economics, automotive mileage, and choice of feedstocks.

Demonstration projects on a small scale now exist, sponsored by DOE, on automotive compatibility of methanol. Ten percent methanol-gasoline blends are being investigated at DOE's laboratories at Bartlesville, Oklahoma. Pure methanol as an automotive fuel is being studied at the University of Santa Clara, in California, under a grant from DOE.

Mobil's methanol to gasoline project is nearing the pilot plant stage, as previously mentioned.

C. Commercialization

1. CAPITAL

In DOE's "Alcohol Fuels Program Plan," it is stated that 10 methanol-from-coal plants, each with a capacity of 1.9 million gallons per day or roughly 700 million gallons per year, could be built by 1990 at an average cumulative investment cost of $450–500 million per plant, or about $5 billion in all. Based on this estimate, each million gallons per year of methanol plant capacity would cost roughly $710,000. Enough methanol capacity for a 10 percent "gasohol" mixture nationwide (i.e. 10 billion gallons of methanol) would cost approximately $7 billion.[5]

2. TIME

Methanol is not likely to be available in significant quantities before 1990. According to DOE, it is unlikely that methanol fuel would be used extensively before that year, because of the planning and construction time required for the building of the large-scale plants necessary for efficient methanol operations. A methanol plant is likely to require 3 to 4 years to build, after perhaps years of negotiating over sites and permits.[6]

3. MATERIAL NEEDS

As stated previously, the material needs with regard to methanol would seem to be adequately met. Ten billion gallons of methanol, enough for a 10 percent blend nationwide, would be obtainable from 38 million tons of coal per year, 6 percent of the present coal output; from 21.7 million acres of forest, 4 percent of the national total; or from 180 million tons of municipal waste, slightly less than the total national output. The use of several resources for methanol production would, of course, reduce the impact on any single resource.

4. ENERGY EXPENDITURE

The most recent estimate by DOE shows that, for a coal-to-methanol conversion plant, 59 percent of the energy originally available in the coal is available in the methanol produced. The remaining 41 percent is used in process heat or otherwise lost. This means that for each BTU consumed in the process, roughly 1.44 BTUs of usable fuel are produced. By way of comparison, in a typical oil refinery 85 to 95 percent of the energy originally available in the crude oil is available in the refined products. This means that for each BTU used, up to 9 BTUs of usable fuel are produced. These statistics are for the conversion plant alone, and do not include the energy necessary for extraction and transportation. Overall estimates which include all energy costs are complex, and

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[5] U.S. Department of Energy, Office of the Under Secretary Task Force on Alcohol Fuels. "Alcohol Fuels Program Plan." March 1978, various pagings.

[6] U.S. Department of Energy. Assistant Secretary for Policy Evaluation. "The Report of the Alcohol Fuels Policy Review," June 1979, 119 p. (p. 106).

none have been made for obtaining methanol from coal, or for converting wood or MSW to methanol.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

The construction of large coal-to-methanol production plants would be a formidable undertaking, as would any large construction project involving technological innovation. However, no insurmountable problems are foreseen.

The problem of automotive compatibility may be serious for methanol. The difficulties previously mentioned, including problems of cold starting, vapor lock, phase separation, compatibility with seals and gaskets, and toxicity, might prevent its use in existing automotive fleets, or perhaps limit the percentage of methanol in the blend to 5 percent as compared with the 10 percent blend already in use with ethanol.

B. Economic

The cost of methanol from coal has been projected by DOE, for the 1980s, to be in the range of 30 to 60 cents per gallon. (By way of comparison, ethanol has been estimated at $1.00 per gallon.)[7] This certainly would be competitive with gasoline, even when the lower BTU value for methanol is taken into account. Methanol has only about half as much energy value per gallon as does gasoline. If this lower BTU value translates to a correspondingly lower miles per gallon figure, then the cost given should be doubled in an economic comparison with gasoline, i.e. methanol with a cost of $.60–$1.20 per 2-gallon unit would be compared with gasoline at a cost of, for example, $1.00 per gallon. However, automotive mileage depends on many factors other than BTU value, and there is at least some evidence (though inconclusive thus far) that mileage with the alcohol fuels is better than would have been predicted from the BTU values.

The capital cost of construction of a methanol plant, estimated to be approximately $500 million for a 700 million gallon per year plant is, of course, an important economic consideration. By way of comparison, $500 million is estimated to buy only 300 million gallons of ethanol capacity, thus methanol plant construction is less expensive than ethanol construction by these DOE estimates.

C. Environmental

The DOE states that methanol plants must be large, i.e., with capacities from 20,000 to 50,000 barrels per day (300 to 750 million gallons per year) in order to be economically attractive; thus small scale methanol plants are considered impractical.[8] For ethanol, on the other hand, a large plant might be impractical, because of the necessity of collecting agricultural materials from large areas and transporting them to the plant over relatively long distances. The

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[7] "Report of the Alcohol Fuels Policy Review," op. cit., p. 14.

[8] U.S. Department of Energy, Assistant Secretary for Policy Evaluation. "The Report of the Alcohol Fuels Policy Review." June 1979, (119p.) p. 7.

difference in capital cost estimates between methanol and ethanol plants is presumably due to the economies of scale available for large plants as opposed to smaller ones.

While combustion of methanol raises no unusual problems, the construction of large coal-to-methanol manufacturing plants may pose environmental pollution problems for the areas in which they are built. (See chapter on "Synthetic Fuels from Coal.")

Methanol is a toxic compound, and its handling might pose difficulties for plant workers, and for service station employees should its use as an automotive fuel become widespread.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

It appears unlikely that methanol will provide any substantial contribution before 1990. The construction of large methanol-from-coal plants is a time-consuming venture which is not likely to be completed before that time. (Note: See also the other chapters on various "synthetic" fuels.)

B. Contribution by 2000 or Beyond

If the decision is made to proceed with a major effort to use methanol as an alternative automotive fuel, its contribution by the year 2000 could be quite substantial. The Department of Energy, in its "Alcohol Fuels Program Plan," envisions twenty coal conversion plants, each producing 6000 tons per day (or 1.9 million gallons per day, or 700 million gallons per year) of methanol.[9] The total output from the 20 plants, of 14 billion gallons per year, would be more than sufficient to supply a 10 percent "gasohol" blend nationwide by the year 2000. This amount of methanol is significantly less than the 54 billion gallons of ethanol predicted by DOE for the year 2000 (see previous chapter). However, it appears possible that the vast coal resources of the Nation—from which methanol can be produced—and the fact that coal is a more concentrated resource than is biomass, may combine to make methanol from coal preferable to ethanol from biomass as the primary source of alcohol fuel in the 21st century.

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[9] Ibid.

NUCLEAR TECHNOLOGIES

ADVANCED CONVERTER REACTORS *

I. SURVEY OF THE CURRENT SITUATION [1]

A. Description of the Technology

Advanced converter reactors are nuclear reactors which have better fuel utilization than current light water reactors (LWRs), but which do not produce more fuel than they consume, as do breeder reactors. Three types of advanced converter reactors will be discussed: improved light water reactors, heavy water reactors (HWRs) and high temperature gas reactors (HTGRs). The terminology used in discussing nuclear fuel cycles (fissile, fertile, enrichment, reprocessing, U-235, plutonium, conversion ratio, etc.) has been discussed in the chapters on Light Water Nuclear Reactors and Breeder Reactors, and hence will not be redefined here.

1. IMPROVED LIGHT WATER REACTORS

Improvements in the fuel utilization of LWRs may be possible by improving the design of nuclear fuels and by changing fuel management techniques. Modifications of reactor cores may be necessary, but it is expected that the changes will be of a nature which will allow them to be retrofitted to existing LWRs.

There are two ways that fuel utilization can be improved. The fuel burnup [2] can be increased for a once-through [3] fuel cycle or the conversion ratio [4] can be improved in a fuel cycle including reprocessing.

As nuclear fuel burns in a converter reactor, the amount of fissionable material decreases and fission products build up in the fuel. Some of the fission products absorb neutrons which might otherwise have caused additional nuclei to fission or have converted fertile isotopes to fissile isotopes. Hence, these fission products are called neutron poisons. Eventually, when there is too large a concentration of neutron poisons, the fuel must be replaced.

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* Prepared by Robert L. Civiak, analyst in energy technology.

[1] In general, where not otherwise noted, technical facts about the various reactor types have been taken from: Nero, Anthony V. A Guidebook to Nuclear Reactors. University of California Press, Berkeley. 1979, 289 p. and programmatic information has been taken from: U.S. Department of Energy. Office of Nuclear Energy Programs. Fission Energy Program of the U.S. Department of Energy. Fiscal year 1980 Washington, U.S. Government Printing Office, April 1979. 317 p. DOE/ET-0089.

[2] Burnup is the total amount of energy released from a given amount of nuclear fuel. It is commonly expressed in megawatt-days per ton (Mwd/t).

[3] Once-through refers to fuel cycles without reprocessing.

[4] Conversion ratio is the ratio of the number of fissile atoms produced from fertile atoms to the number of fissile atoms consumed in a reactor.

Some changes in fuel and core design can improve both burnup and the conversion ratio. These include changes in the coolant, moderator, fuel cladding, and reactor controls which decrease the number of neutrons lost to these sources. However, burnup is greatest when the fuel is kept in the reactor a long time, but conversion is highest for fresh fuel, which means that maximizing the conversion ratio requires frequent fuel changes. Thus, some tradeoff must be made between high burnup and a high conversion ratio.

In LWRs the conversion ratio can theoretically be higher for U-233/Th fuels than for the currently used U-235/Pu fuels. Thorium-based fuel cycles are being studied for this reason and because thorium-based fuel cycles may be preferable to plutonium-based fuel cycles from the standpoint of nuclear proliferation. The technology required to increase the conversion ratio for U-233/Th fuels is similar to that needed to produce a light water breeder reactor. Hence, information obtained from light water breeder reactor development could be applied to the development of high conversion thorium-fueled light water converter reactors.

2. HEAVY WATER REACTORS

A heavy water reactor uses water made from deuterium [5] as both a coolant and a moderator. Since heavy water absorbs fewer neutrons than ordinary (light) water, HWRs can achieve both higher burnup and higher conversion ratios than is possible with LWRs. Heavy water reactors are currently produced commercially in Canada (CANDU reactors). These reactors operate using naturally occurring uranium without enrichment and, for a once-through fuel cycle, require about 20 percent less fuel over a thirty year lifetime than an LWR producing an equivalent amount of power.

Improvements in fuel utilization can be realized by mixing heavy water and light water in varying proportions depending upon the age of the fuel. This type of reactor is called a spectral shift reactor. Higher conversion ratios in heavy water and spectral shift reactors are possible with thorium-based fuels than with plutonium-based fuels.

3. HIGH TEMPERATURE GAS REACTORS

High temperature gas reactors (HTGRs) are considerably different from LWRs or HWRs. The fuel pellets, rather than being supported in long fuel rods, are incorporated into graphite blocks which serve as moderators in addition to providing structural support. Since graphite is not as effective a moderator as water, the core must be as much as ten times larger in an HTGR than an LWR of equal power to provide sufficient graphite to slow the neutrons. The fuel most often considered for HTGRs consists of moderately or highly enriched uranium with thorium present as a fertile material, although U-235/Pu fuels are also possible.

The primary core coolant in an HTGR is helium gas. Since the coolant is a gas, the operating temperature can be much higher than that of a water cooled reactor. This higher operating tempera-

[5] Deuterium is an isotope of hydrogen possessing an additional neutron.

ture results in a higher thermal efficiency [6] for the HTGR than for water cooled reactors. The higher thermal efficiencies, as well as improved burnup and conversion ratios, could lead to better fuel utilization in HTGRs than in current LWRs.

B. Known Resources and Reserves

The situation with respect to fissionable resources is discussed in the chapters on Light Water Nuclear Reactors and Breeder Reactors. In brief, resources may be sufficient for 20–50 years of operation with current LWRs and virtually inexhaustible if breeder reactors are introduced. A key question is how soon will breeder reactors be needed, if at all?

Advanced converter reactors could play a role in determining the answer to that question. Large increases in uranium utilization which might be possible with converter reactors could, in principle, extend fissionable resources for many decades, or even centuries without the use of breeder reactors. However, these reactors might not be preferable to breeder reactors from economic, safety, or proliferation standpoints. Moreover, such high conversion reactors are further from development than breeder reactors. More modest improvements in uranium utilization might be achievable with converter reactors in the short term. It has been estimated that such improvements could delay the need for introduction of breeder reactors for 3 to 17 years.[7]

C. Current Contribution to U.S. Energy Supplies

N/A.

D. State-of-the-Art

1. IMPROVED LIGHT WATER REACTORS

Currently, nuclear fuel is discharged from a typical commercial LWR after it has produced an average burnup of 25,000 to 33,000 Mwd/t. Conversion ratios are about 0.6. Selected fuel assemblies have been reinserted into commercial reactor cores in experimental programs and achieved burnups of over 40,000 Mwd/t. One of the chief problems limiting higher burnup is a degradation of the Zircaloy cladding that encloses the fuel pellets, which necessitates the removal of the fuel for safety related reasons. This problem, called the pellet-clad interaction (PCI), is caused by mechanical stresses between the fuel and the cladding and chemical attack caused by the release of corrosive fission products from the fuel.

2. HEAVY WATER REACTORS

Nine CANDU heavy water reactors are currently in commercial operation in Canada, producing over 5,000 Mw of electricity. Several more are under construction or on order in Canada and other countries. The United States has little experience with heavy water reactors.

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[6] Thermal efficiency is the percentage of heat energy produced which is converted into electricity. LWRs have a thermal efficiency of about 31 percent and HTGRs can achieve 39 percent thermal efficiencies.

[7] U.S. Department of Energy. Office on Energy Research. The Nuclear Strategy of the Department of Energy. April 1979 (DOE/ER-0025-D) p. 19.

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3. HIGH TEMPERATURE GAS REACTORS

Great Britain has substantial commercial experience with gas cooled reactors which use gases other than helium. In the United States, one commercial HTGR cooled by helium gas is currently being operated at Fort St. Vrain, Colorado by the Public Service Company of Colorado. The Fort St. Vrain plant, designed to operate at 330 Mw, began operation in December 1976. However, technical problems have caused the Nuclear Regulatory Commission to limit its operation to 70 percent of full power.[8]

In 1974, the General Atomic Co., which built the Fort St. Vrain plant, had commitments for 10 HTGRs from 700 Mw to 1,200 Mw. All were subsequently cancelled for a variety of business and economic reasons.

E. Current Research and Development

1. IMPROVED LIGHT WATER REACTORS

Increasing the efficiency of uranium utilization of LWRs operating in a once-through mode is the objective of the Uranium Utilization Program Element of DOE's Thermal Reactor Technology Program. The DOE believes that it may be possible to demonstrate fuels and fuel management techniques which can produce a 15 percent savings of uranium by 1988 and an additional 15 percent by 2000.[9] These techniques are expected to be applicable to LWRs currently operating and those beginning operation prior to those dates.

In one experimental program, selected nuclear fuel assemblies are undergoing high burnup tests in the Oconee-1 reactor in a DOE project in cooperation with the Duke Power Company. Information from this project will be used to design improved assemblies which will be inserted into reactors operated by the Arkansas Power and Light Company between 1980 and 1982. These projects are expected to lead to the design of complete fuel reloads capable of a burnup of 46,000 Mwd/t by 1986.

As a result of the President's decision in April 1977 that the United States would defer indefinitely the commercial reprocessing and recycling of plutonium, the DOE is no longer performing research on improving conversion in LWRs operating with U-235/Pu fuels which would require reprocessing in order to provide improved uranium utilization. Efforts to increase the conversion ratio in light water reactors operating on U-233/Th fuel cycles are continuing as part of the light water breeder reactor program and are discussed in the section on Breeder Reactors.

2. HEAVY WATER REACTORS

The United States does not currently have any development program for heavy water reactors. Atomic Energy of Canada Ltd. (AECL) is considering possible improvements to the CANDU reac-

[8] Among the problems has been the occurrence of temperature fluctuations in the reactor core. Experience acquired from the plant's first three years of operation is expected to lead to a solution to this problem.

[9] U.S. Department of Energy. Office of Nuclear Energy Programs. Fission Energy Program of the U.S. Department of Energy. Washington, U.S. Government Printing Office, April 1979. DOE/ET-0089, p. 30.

tors. Currently CANDUs require about 20 percent less uranium over a 30 year plant lifetime on a once-though fuel cycle than do LWRs. However, reprocessing, which could improve LWR fuel utilization by about 30 percent, is not economically feasible for current CANDUs because only a small amount of fissionable material remains in the spent fuel. The AECL is investigating the possibility of operating CANDUs with enriched uranium and/or on a thorium-based fuel cycle. These developments have the potential of increasing the conversion ratios of these reactors to 0.9 or higher and making reprocessing feasible.

3. HIGH TEMPERATURE GAS REACTORS

In the original General Atomic design for the HTGR, the helium gas is used to produce steam to run a steam turbine generator. In 1978, General Atomic decided that it would no longer offer this reactor because of the marginal economics of the steam-cycle design. Since then, interest in HTGRs in the United States has focused on long term research and development in connection with new HTGR designs.

Funding for research on two new types of HTGRs has been provided to DOE through fiscal year 1980. The first is the direct cycle HTGR, in which the helium coolant is allowed to expand and run a gas turbine generator directly. The second type, sometimes called the very high temperature reactor (VHTR), would operate at higher temperatures than othe gas reactors and provide steam for industrial processes. One possible use of this process steam is in the production of synthetic fuels.

In the United States, work on HTGRs is being performed by the General Atomic Company, General Electric, Westinghouse and DOE. In 1978, a group of utilities formed the Gas Cooled Reactor Associates (GCRA) to coordinate the activities of these organizations and to promote HTGRs. The GCRA has produced a development schedule according to which a commercial sized HTGR gas turbine demonstration plant could be in operation by the early 1990s. The GCRA plan calls for parallel development and demonstration of process heat application with the VHTR and commercial deployment of both the gas turbine and process heat reactors near the turn of the century. This development schedule has not been accepted by the Department of Energy, however.

The DOE is currently evaluating conceptual design studies for both direct-cycle HTGRs and VHTRs for process heat applications. Work is also proceeding in the study of fuels, materials and safety of HTGRs.

The United States, the Federal Republic of Germany, France and Switzerland are cooperating in the development of the HTGR under an agreement signed in February 1977. Cooperation is in several areas of technology development.

The Administration has decided for budgetary reasons not to request any funding for HTGR development of fiscal year 1981. However, it is possible for Congress to restore DOE funding for HTGR research and development. Federal funding for advanced converter reactors amounted to about $47 million for fiscal year 1980.

II. Prospects or Requirements for Further Development

Improved LWRs and HTGRs are the only converter reactors which are currently being developed in the United States. Hence, only those designs will be considered in this section.

A. Research and Development

1. IMPROVED LIGHT WATER REACTORS

A major problem with increasing the lifetime, and hence the burnup, of LWR fuels is the degradation of the cladding that encloses the fuel pellets, which occurs through interactions with the pellets themselves. Two projects to alleviate the pellet-clad interaction problem are currently underway and scheduled for completion in 1985. Additional methods for improving uranium utilization in LWRs are being investigated in a joint Tennessee Valley Administration/DOE project which began in 1979 and is scheduled to continue until 1988.

2. HIGH TEMPERATURE GAS REACTORS

Additional research is needed in the areas of HTGR fuels, graphite, materials, safety, components and sytems. This effort, as well as analysis of conceptual designs of direct-cycle HTGR plant configurations, VHTR process heat reactors, and a German designed HTGR is necessary in order to choose the most promising design for further development.

The current effort is in the nature of technology development. Since no single HTGR design has been chosen for development and no development schedule established, no estimates are available on how large a research effort is needed. The DOE spent $42 million on HTGR development in fiscal year 1979. The fiscal year 1980 appropriation is only $25 million, reflecting the terminaition of development of the steam-cycle HTGR. The Administration has decided to cancel all HTGR funding for fiscal year 1981. However, funds could be restored by Congress.

Although General Atomic has spent nearly $1 billion on the development of steam-cycle HTGRs in the past 20 years, private spending in the United States on HTGR development is expected to be less than $1 million in 1980.[10]

B. Demonstration

1. IMPROVED LIGHT WATER REACTORS

Utility acceptance of improvements in LWR fuels will require demonstrations in commercial LWRs. Such demonstration involves in-plant irradiations of large quantities of fuel fabricated by industrial manufacturing techniques, experience with normal licensing procedures, and multi-year testing in an operating environment typical of large commercial reactors. Current DOE/utility experimental programs for the testing of high burnup fuels are expected to lead to the design and fabrication of an entire reload batch of

[10] U.S. Department of Energy, HTGR Program Office.

fuel which will be inserted into a commercial reactor after 1986 to demonstrate both high burnup and economical operation.[11]

2. HIGH TEMPERATURE GAS REACTORS

The Gas Cooled Reactor Associates has estimated that a direct-cycle HTGR commercial demonstration plant could be in operation by the early 1990s. However, the DOE currently has no plans for the development of a demonstration HTGR. Estimates of the cost of a development program for an HTGR through a demonstration plant are very speculative, since no specific design has been selected, but they range from two to five billion dollars.

C. Commercialization[12]

2. IMPROVED LIGHT WATER REACTORS

If improvements in LWR fuels and core designs are demonstrated to result in lower costs and increased uranium utilization, it could be possible for commercialization to proceed rapidly. It is expected that the changes necessary to achieve the first 15 percent inprovement in uranium utilization can be retrofitted to existing LWRs.

The DOE estimates that the technology to achieve a 15 percent savings in uranium, and a decrease in fuel costs, could be available by 1988, and that longer-term improvements that have the potential of reducing uranium consumption in LWRs by an additional 15 percent could be available by 2000.

2. HIGH TEMPERATURE GAS REACTORS

Steam-cycle HTGRs reached the stage of commercialization in the early 1970s, but were rejected for economic reasons. If circumstances were to change, commercial steam-cycle plants could be available in 10 to 15 years, which is the time needed to license a new nuclear plant. Other HTGR designs are in the early stages of technology development. Hence, it would be premature to estimate the requirements for commercialization.

III. Potential Obstacles to R. & D. or Technology Implementation

Many of the obstacles to the growth of nuclear power which are discussed in the chapter on Light Water Nuclear Reactors also apply to advanced converter reactor. Only additional obstacles to the development and implementation of improved LWRs and HTGRs will be discussed here.

A. Technical

A major problem that needs to be resolved if high burnup is to be achieved in LWRs is the pellet-clad interaction (PCI) discussed earlier. A number of current approaches to solving this problem appear promising.

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[11] Fission Energy Program of the U.S. Department of Energy, op. cit. p. 31.
[12] Nero, Anthony V. and DOE Office of Nuclear Energy Programs., op. cit.

Direct cycle HTGRs and VHTRs for process heat are in the early stages of technology development. The basic operating principles of HTGRs have been proven through development of steam-cycle HTGRs, but many engineering problems need to be worked out for the new designs. It does not appear that absolute technical barriers to these designs exist. Rather, technical problems that have an effect on the economics of the system need to be solved.

B. Economic

Refueling of an LWR requires that the reactor be shut down for a few weeks. A utility can save money by refueling when a reactor needs to be shut down for other reasons or by scheduling refueling during periods of low electricity demand. Fuel management techniques which maximize burnup may not be economically acceptable if there is a substantial loss of flexibility in the scheduling of refueling.

After many years of development, the General Atomic Company discontinued the steam-cycle HTGR because it did not appear to be economically competitive with current LWRs. Other HTGR designs are in the early stages of development and so it is not yet known how the cost of power or heat from those designs will compare with other sources.

C. Environmental

See: Light Water Nuclear Reactors, III. C.

D. Social

See: Light Water Nuclear Reactors, III. D.

E. Political

There is currently considerable uncertainty over the future of nuclear power. If the nuclear power option is to be maintained, in the short term LWRs will predominate and in the long term breeder reactors will be more important. Only after the future of these technologies has been decided can programs for the development of advanced converter reactors be fit into the overall policy for the development of nuclear energy in a consistent manner. At this time the development of advanced converter reactors is proceeding slowly pending clarification of the broader nuclear policy issues.

E. Other

See: Light Water Nuclear Reactors, III. E.

IV. Potential Contribution to U.S. Energy Supplies

The contribution of all forms of nuclear fission to U.S. energy supplies is discussed in the chapter on Light Water Nuclear Reactors. Advanced converter reactors will not represent a direct additional contribution. Rather they may replace other nuclear reactors if they provide better fuel utilization and economics, or are preferred for other reasons.

A. Contribution by 1990

Since it takes ten years or more to license and construct a nuclear reactor and no reactors other than light water reactors are currently on order or under construction in the United States, it appears that only LWRs will make a contribution to 1990 energy supplies.

It may be possible to retrofit improvements in the design of fuels and reactor cores to existing and planned light water reactors. The DOE has estimated that changes which can result in a 15 percent savings of uranium may be available by 1990.

B. Contribution by 2000 or Beyond

The DOE has estimated that by 2000 improvements in LWRs may result in an additional 15 percent savings of uranium above that predicted for 1990. However, this prediction is challenged by those who believe that breeder reactors are needed soon in order to insure that sufficient supplies of fissile materials will be available.

The Gas Cooled Associates has predicted that direct-cycle HTGRs could be commercialized before the year 2000. However, their development schedule calls for a demonstration plant to begin operation in the early 1990s. There are currently no plans in the United States for such a demonstration plant, and it would likely take more than ten years to design, license and build.

The technology for steam-cycle HTGRs is well enough developed that reactors of that design could be in put into operation before 2000. However, steam-cycle HTGRs have recently been rejected by utilities on economic grounds and discontinued by General Atomic, which spent nearly $1 billion on their development.

It is too early to predict what types of advanced converter reactors may be available in the long term after the year 2000. The only other converter reactor technology (besides improved LWRs and HTGRs) which could be introduced before or shortly after the year 2000 is the heavy water reactor. Since very little development has taken place on heavy water reactors in the United States, introduction of this reactor design before 2000 would require that the United States acquire existing Canadian technology for heavy water reactors.

BREEDER REACTORS *

I. SURVEY OF THE CURRENT SITUATION

A. Description of the Technology[1]

The term breeder reactor refers to a type of nuclear reactor which, in addition to producing energy, is able to produce more usable nuclear fuel than it consumes. There are two kinds of breeders, distinguished by the type of coolant used, which currently have development programs receiving substantial funding in the United States. These are the Liquid Metal Fast Breeder Reactor and the Light Water Breeder Reactor. Two other types, the Gas Cooled Fast Reactor and the Molten Salt Breeder Reactor, have received attention in the past.

Uranium-235 (U-235) is the only naturally occurring isotope which will fission in a manner suitable for use in a nuclear reactor. Such isotopes are called fissile. Uranium-235 comprises only 0.7 percent of naturally occurring uranium, the other 99.3 percent of which is Uranium-238 (U-238). However, U-238, as well as another naturally occurring isotope, thorium-232 (Th-232), are fertile; that is, they can be converted to fissile isotopes [2] by the addition of a single neutron.

All nuclear reactor fuels are designed to include fertile as well as fissile materials. During normal operation, some atoms of the fertile isotope are converted to fissile isotopes which can then fission and release energy. Current Light Water Reactors (LWRs) convert about 60 fertile atoms to fissile isotopes for every 100 atoms which fission. A reactor is called a breeder reactor if it can covnert more than 100 fertile atoms for every 100 atoms which fission—hence, producing more fuel than it consumes.[3] Of course the fertile material is consumed, but the United States has a large stockpile of U-238, which was left over when the U-235 was removed, that can fuel breeder reactors for many years. Maximum use of U-238 in breeder reactor fuel cycles would enable about 60 times as much energy to be produced from a quantity of natural uranium as is currently produced. In addition, thorium could also be used in breeder reactors.

The Liquid Metal Fast Breeder Reactor (LMFBR) is the most developed of the various breeder designs. In this type of reactor, a liquid metal (most commonly sodium) is used to cool the reactor core and transfer the heat to water, which boils to produce steam that runs a turbine generator. The reactor is called a fast reactor

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* Prepared by Robert L. Civiak, analyst in energy technology, and Marcia Smith, specialist in aerospace and energy technology.

[1] More detailed descriptions of the technologies described here can be found in: Nero, Anthony V. A Guidebook to Nuclear Reactors. Berkeley, U. of California Press, 1979. 289 p.

[2] U-238 into Plutonium-239 (Pu-239) and Th-232 into uranium-233 (U-233).

[3] The number of new fissile atoms created per atom of fissile material consumed is called the conversion ratio or breeding ratio. Current LWRs have a conversion ratio of about 0.6. A conversion ratio of greater than one characterizes a breeder reactor.

because the neutrons which are emitted by the fission reaction are not slowed down as they are in conventinal light water reactors. New heterogeneous core designs suggest the possibility of theoretical breeding ratios as high as 1.44 for LMFBRS. However, this figure is not expected to be achieved in early breeder reactors which might have breeding ratios of 1.2 to 1.3.

Two types of LMFBRs, which differ in the way that heat is removed from the reactor, have been built. They are the "loop" design and the "pool" design. In the United States, work has focused on the loop design, which was developed first. It is not yet clear if the pool design, on which France is focussing its development effort, will prove to be as good or as better than the loop design. LMFBRs can in principle operate on either a U-233/Th or a U-238/Pu cycle. However, development has concentrated on the U-238/Pu cycle because of the superior theoretical breeding ratio possible with plutonium in fast reactors.

Three other breeder reactor designs have received some attention in the United States, but are not as far advanced as the LMFBR. The first, the Gas Cooled Fast Reactor (GCFR), uses helium gas as a coolant. Breeding ratios of 1.5 on a plutonium cycle and 1.1 on a thorium cycle might be possible with this design.

The second, the Light Water Breeder Reactor (LWBR), is essentially a light water reactor with a core designed to maximuze conversion of fertile material. This design can only breed on a U-233/Th fuel cycle and has a maximum theoretical breeding ratio of about 1.02.

In the 1960's, the United States operated an experimental Molten Salt Breeder Reactor (MSBR), in which the fuel itself is a liquid containing lithium, beryllium, thorium and U-233 flouride salts. The liquid is pumped through heat exchangers to be cooled. The theoretical breeding ratio for the MSBR design is between 1.05 and 1.07. Some still consider the MSBR promising. However, severe technical problems remain to be solved with this design and the U.S. Department of Energy (DOE) has not requested funding for the MSBR for several years.

B. Known Resources and Reserves

Uranium resource estimates are discussed in the Conventional Light Water Reactors chapter. It is noted there that, with current nuclear technology, uranium resources should be sufficient for about 12,000 reactor-years of operation.[4] If the rate of introduction of nuclear power plants is near the middle of the range discussed in that section (260 Gw by 2000), if it continues in the same manner past the year 2000, and if there is no substantial increase in the amount of electricity generated from a ton of mined uranium, U.S. supplies of economically retrievable uranium could be totally consumed sometime in the first quarter of the 21st century.

[4] In 1,000 MW reactors operating at 65 percent capacity factor.

However, improvements in uranium enrichment techniques,[5] and the introduction of reprocessing[6] of spent nuclear fuel, could extend uranium resources. In addition, the technologies discussed in the Advanced Converter Reactors chapter could result in improved uranium utilization, or in the use of thorium as a nuclear fuel, which would further extend the availability of nuclear fission resources. Further exploration might also uncover additional uranium resources.

Several of these developments could extend fission resources well into the second half of the 21st century. However, none of them is certain to occur and, if nuclear fission is to remain a viable energy option in the very long term, it will eventually be necessary to introduce some form of breeder reactor.[7]

If breeder reactors could increase fuel utilization by a factor of 60, current resources would be sufficient to provide many centuries of energy from nuclear power. In fact, utilization of current stockpiles of U-238 could eliminate the need to mine uranium for may years.

C. Current Contribution to U.S. Energy Supplies

Breeder reactors are not currently contributing to U.S. energy supplies.

D. State-of-the-Art

Although the first liquid metal fast reactor began operation in 1945, the LMFBR is still in the demonstration phase of development in the United States and abroad.

The Experimental Breeder Reactor (EBR I), an LMFBR built by the Atomic Energy Commission, produced the world's first electricity from nuclear power in 1951, and proved that the breeding theory was correct. Several other experimental and demonstration LMFBRs have been operated in the United States since then, including the Enrico Fermi Power Plant. This privately owned 61 Mw[8] plant, located near Detroit, produced the first commercial electricity from a breeder in 1963. The Fermi plant suffered an accident which led to some melting of fuel in 1966. After restoring the plant in 1970, it was determined that it was not economically competitive with other methods of electricity generation and the plant was shut down in 1972.

The largest operating LMFBR in the world is the 600 Mw BN-600 in the Soviet Union, which began operation in April 1980. Still

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[5] Naturally occurring uranium contains 0.7 percent U-235. This must be increased to from 2 to 4 percent for the uranium to be used as fuel in LWRs. Increasing the amount of U-235 in a supply of uranium is called enrichment. In order to enrich part of a supply of uranium, it is necessary to deplete the rest of the supply. The amount of U-235 remaining in the depleted uranium is called the tails assay. Current enrichment methods are not economical with a tails assay below 0.2 percent. Introduction of advanced enrichment methods, which could reduce the tails assay to 0.05 percent, would represent a 30 percent increase in the amount of usable uranium.

[6] About one-third of the fuel from an LWR must be removed and replaced each year. Roughly half of the energy content of the fissile portion of fresh fuel remains in the spent fuel in the form of unused U-235 and Pu which has been created. Reprocessing refers to a series of procedures by which the fissile material can be recovered from the spent fuel and used to make fresh fuel. Reprocessing could reduce a typical LWR's lifetime fuel use by one-third.

[7] The Carter administration does not believe that introduction of breeder reactors will be necessary before 2020. However, others claim that uranium resources will be inadequate if breeders are not introduced sooner.

[8] In this chapter the abbreviation Mw will refer only to electrical power; Mwt, or thermal megawatts, will be used when referring to heat production. About one-third of the thermal power produced in a nuclear reactor can be transformed into electricity.

larger reactors are required in order to be economically competitive with other methods of electricity generation.

Breeder reactor designs other than the LMFBR are in the technology development or early experimental stage and have yet to demonstrate breeding.

E. Current Research and Development

The fiscal year 1979 spending by DOE for all breeder reactor research and development was $563 million for LMFBRs, $63 million for LWBRs and $26 million for GCFRs. FY80 appropriations are $615 million for LMFBRs, $60 million for LWBRs and $26 million for GCFRs. Total FY 80 Federal funding amounted to about $742 million.

1. LIQUID METAL FAST BREEDER REACTORS

The major facilities for the development of LMFBRs in the United States are the Experimental Breeder Reactor II (EBR II) and the Fast Flux Test Facility (FFTF). A highly controversial facility, the Clinch River Breeder Reactor Project (CRBRP), has been designed and some equipment has been built and delivered, but construction has not begun at the site.

The EBR II, located at DOE's Idaho National Engineering Laboratory (INEL) in Southeastern Idaho, is a 62.5 Mwt sodium-cooled pool-type fast reactor used primarily for safety, fuels, and materials experiments.

The FFTF, located at Hanford, Washington, is a larger facility than EBR II and is also designed to test breeder reactor fuels and materials and to acquire experience in design, development and construction leading to an LMFBR demonstration plant. This 400 Mwt facility began operation in February 1980.

The proposed CRBRP, designed as a 380 Mw sodium-cooled loop-type LMFBR, is intended to demonstrate commercial feasibility of breeder reactors. The completion of this facility is currently a subject of disagreement between the Carter Administration and the Congress. The escalating cost of the plant, coupled with concern over the weapons proliferation potential of the plutonium which this type of reactor will breed, has led to efforts by the Administration to cancel the project and redirect national efforts towards alternative breeder concepts which would not produce plutonium. Congressional action has supported CRBRP despite the President's position, but work on the project has fallen considerably behind schedule. Originally, CRBRP was to have begun operation in 1982. If the project were now to proceed without further delay, it is estimated that its operation could begin in 1988.

The United States is only one of several countries actively engaged in LMFBR programs. France, the United Kingdom, and the Soviet Union all have operating demonstration LMFBRs larger than any built thus far in the United States. In addition, those three countries and the Federal Republic of Germany all have commercial scale plants scheduled for operation in the 1980s, although only France has started construction. Table 7 summarizes foreign LMFBR facilities larger than 50 Mw.

TABLE 7.—FOREIGN LMFBR FACILITIES LARGER THAN 50 Mw.

Country	Facility	Power (Mw)	Operating date
France	Phenix	250	1973.
France (1)	Super-Phenix	1,200	1983.
Germany (2)	SNR-300	300	1982.
Germany (3)	SNR-2	1,300	Late 1980's.
Japan	Monju	300	1987.
United Kingdom	PFR	250	1974.
United Kingdom	CFR	1,300	Late 1980's.
U.S.S.R.	BN-350	350	1973.
U.S.S.R.	BN-600	600	1980.
U.S.S.R.	BN-1600	1,600	Late 1980's.

[1] Utility ownership: France 51 percent, Italy 33 percent, Germany 16 percent.
[2] DEBENE consortium (Belgium, Germany, and the Netherlands).
[3] Utility ownership: Germany 51 percent, Italy 33 percent, France 16 percent.

In addition, Japan and Italy are operating smaller experimental LMFBRs and several other countries are participating in cooperative breeder programs.

2. LIGHT WATER BREEDER REACTORS

The immediate objective of DOE's Water Cooled Breeder program is to confirm that breeding can be achieved in existing and future light water cooled reactor systems using the U-233/Th fuel system. An LWBR core has been developed and is now operating in the Shippingport Atomic Power Station, in Western Pennsylvania. It is expected that when this core is removed, in 1981 and 1982, it will contain about one percent more fissile material than was present in the original fuel.

3. GAS-COOLED FAST REACTORS

The DOE program for the development of GCFRs is one of three interrelated programs. The other two are a program supported by the General Atomic Company and the Helium Breeders Associates (HBA)[9], and an international program carried out under an agreement between the United States, the Federal Republic of Germany, France and Switzerland. The DOE accounts for about half of the funding for support of GCFR development. The DOE has contracted with HBA to provide overall management of the GCFR program.

Development of the GCFR by the DOE has been viewed as a backup to the LMFBR[10], and hence no formal commericalization program was planned for GCFR. For fiscal year 1980, $26 million was appropriated for GCFR research and development, but the Administration decided to terminate the program in fiscal year 1981 and requested no funding for GCFRs. Funding remaining from the fiscal year 1980 appropriation would allow development work to continue on systems, components, fuel, and safety. However, in his March 1980 revision to the fiscal year 1981 budget

[9] HBA is comprised of utility companies which represent about 30 percent of the electrical generating capacity in the United States.

[10] U.S. Department of Energy. Office of Nuclear Energy Programs. Fission Energy Program of the U.S. Department of Energy. Washington, U.S. Government Printing Office, April 1979. DOE/ES-0089, p. 230.

request, the President recommended terminating the GCFR program earlier than originally planned, thereby saving $8 million.

The major DOE program for GCFR development are the Core Flow Test Loop (CFTL) and the Gas Reactor In-Pile Safety Test (GRIST-2). The CFTL is a non-nuclear test facility to analyze heat removal problems in GCFR reactors. GRIST-2 is a test reactor loop for the study of fuel behavior.

Efforts are underway for the U.S., West Germany, France, Switzerland and Belgium to develop a single international GCFR design. Major foreign contributions are in the design, fabrication and testing of fuels in the Belgian BR-2 test reactor, and in heat transfer experiments in the Agathe loop in Switzerland.

4. MOLTEN SALT BREEDER REACTORS

The United States operated the Molten Salt Reactor Experiment (MSRE) from 1965 to 1969 at Oak Ridge National Laboratory in Tennessee. The 7.4 Mwt reactor circulated fuel salt at approximately 1200 degrees F for a total of 2½ years.[11] In February 1973, the AEC terminated the MSBR program, but it was reinstated early in 1974 and continued until the end of fiscal year 1976. Although DOE has not requested funding for MSBR since that time, it is among the breeder designs being reevaluated in light of new concerns about the proliferation dangers of plutonium. Operating on the thorium cycle, the MSBR has the highest breeding ratio of the thorium breeders, and since the fuel is liquid and on-line processing is possible, there would be a much smaller loss of newly created fissile material than would occur in the out-of-reactor reprocessing and refabricating steps required with the other breeder designs which would lose up to 2 percent of the new fissile materials.

II. Prospects or Requirements for Further Development

A. *Research and Development*

The LMFBR is in the demonstration stage of development. Its requirements for further development are discussed in B.1, below.

1. LIGHT WATER BREEDER REACTORS

The LWBR is in the technology development stage. The main goal at this stage is to show that it is possible for a LWBR to produce more fuel than it consumes. An experimental LWBR core is scheduled to be fully removed from the Shippingport reactor by 1982. Analysis of this core to determine if breeding has been accomplished and to learn more about the interactions between the fuel, moderator and coolant in a light water reactor fueled with U-233 and thorium will continue until 1984. If these yield favorable results, demonstration activities to define the economics of the system could begin. The DOE estimates that funds required for this program for fiscal year 1980 through fiscal year 1984 will be $267 million 1980 dollars.

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[11] McNeese, L. E., and M. W. Rosenthal. MSBR: A Review of Its Status and Future. Nuclear News, September 1974: 51.

2. GAS-COOLED FAST REACTORS

Research and development of the GCFR is being conducted under a jointly funded government-industry Program Definition and Licensing Phase (PDLP) effort, which is coordinated with German, French, Swiss and Belgian programs under an international umbrella agreement. This phase was scheduled to end in 1985, although the Carter Administration's decision to terminate the program after fiscal year 1980 will obviously impact this plan. By 1985, the engineering design of a demonstration GCFR was expected to be about 70 percent complete and sufficient supporting information was to have been available to allow cost studies to be performed which would enable a decision to be made regarding the construction of a demonstration plant.

The DOE estimates that the development of a GCFR is about ten years behind the LMFBR, and that it would take roughly $1 billion to close this gap.[12]

3. MOLTEN SALT BREEDER REACTOR

The MSBR is the least developed of any of the breeder designs. Although the basic reactor physics is thought to be well known from the MSRE program, other areas still require significant investigation (see section III. A.) before any decision could be made concerning development or commercialization of this technology.

B. Demonstration

1. LIQUID METAL FAST BREEDER REACTORS

According to the DOE, if the Administration and the Congress agree to proceed with construction of the CRBRP, the facility could begin operation in 1988. With this starting date, the total cost of the project is estimated to be $2.6 billion.[13] According to the General Accounting Office, DOE spent $0.7 billion through September 30, 1979 on CRBRP and the total industry contribution to the project will be $0.3 billion. Hence, the remaining cost of the project to the Federal Government is estimated to be $1.6 billion.

If CRBRP is completed, it will have to be followed by the operation of a full scale LMFBR (sometimes referred to as the Prototype Large Breeder Reactor, PLBR) before commercialization efforts can begin. Some opponents of the Clinch River project claim that, if CRBRP was cancelled, work could begin immediately on a 600 to 900 Mw LMFBR, which could be operating by the early 1990s. While the Administration favors cancellation of CRBRP, thus far it has agreed only to replace it with studies of a PLBR rather than to make a commitment to its construction.

Estimates of the earliest date for initial operation of a PLBR vary from the early 1990s to after the year 2000. Estimates of the cost of this plant are not available. In addition, it is not yet clear if

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[12] U.S. Congress. House. Committee on Science and Technology. Subcommittee on Fossil and Nuclear Energy Research, Development and Demonstration. 1979 Department of Energy Authorization. Hearings, 95th Congress, 2d session. Feb. 2, 7, 8, 1978. V. III. Nuclear Energy Research, p. 791.

[13] U.S. General Accounting Office. The Clinch River Breeder Reactor—Should the Congress Continue to Fund It? Washington, U.S. Government Printing Office, May 7, 1979, 31 p. EMD-79-62.

this would be the last demonstration reactor required before commercialization.

2. LIGHT WATER BREEDER REACTORS

The requirements for future demonstration activities in connection with LWBRs is dependent upon present development efforts. No time scale or cost estimate has been established for a LWBR demonstration. However, since a demonstration LWBR reactor core can be placed in a modified light water reactor, the cost of a demonstration program for this technology might be considerably less than that required for the LMFBR, which requires the development of a completely new power plant technology.

3. GAS-COOLED FAST REACTORS

The Carter Administration's decision to terminate the GCFR program at the end of fiscal year 1980 makes such a scenario unlikely, but if a decision were made to build a demonstration GCFR at the end of the Program Demonstration and Licensing Phase (PDLP) in 1985, such a plant might be built by the early to mid 1990's. The cost of this plant might be shared by DOE, industrial groups, and the foreign countries participating in the present development effort. It has not yet been established whether another demonstration plant would have to follow this effort before commercialization could begin.

C. Commercialization

Commercialization efforts have not yet begun in the United States for any breeder design. However, commercialization activities in connection with LMFBRs are underway in several other countries. Given a vigorous and successful demonstration program through the PLBR, the first commercial LMFBRs could appear in the United States shortly after the year 2000—additional plants could follow soon thereafter. Breeder reactors, and their associated converter reactors which use the bred fuel, could in principle account for nearly all new electricity generation capacity ordered after a one to two decade introductory period. However, this is dependent upon the alternatives available and many of the factors discussed in section III below.

A commercial GCFR might also be available shortly after 2000, if that design is chosen for vigorous pursuit and only one demonstration plant is needed. However, if a second demonstration plant is required, commercialization could be set back at least another 10 years.

If LWBRs are successfully demonstrated, the first commercial plants could possibly be in operation before the year 2000. This early introduction of LWBR technology could occur if light water breeder cores are compatible with then-existing LWRs being deployed. However, a supply of U-235 would have to be developed before a large number of LWBRs could operate. This requires that non-breeding light water reactors be operated with "pre-breeder cores," which are fueled primarily with U-235 and convert thorium into U-233, but produce less fuel then they consume. Breeder cores could then be fueled with the U-233 produced.[14]

III. Potential Obstacles to R. & D. or Technology Implementation

This section will discuss only obstacles to the implementation of breeder reactors. The many problems which face all forms of nuclear energy are discussed in the chapter on Conventional Light Water Nuclear Reactors.

A. Technical

At this time, there are no known technical barriers to the development of LMFBRs or GCFRs. However, technical problems might arise as power plants are scaled up, and could lead to long delays in the implementation of these technologies.

The prospects for eventual development of LWBRs are not quite so certain. Breeding has yet to be demonstrated for LWBRs and the maximum conversion ratio expected for this type of reactor is only about 1.02. It is possible that technical problems could prohibit the achievement of conversion ratios greater than one.[15]

A number of technical obstacles remain with the MSBR concept. The most serious problems involve developing materials capable of containing the corrosive molten salt mixture. Another problem area is removing tritium, which is produced from lithium in the fuel salt so that it does not reach the steam system and escape into the environment.

Reprocessing of spent fuel is an integral part of any breeder reactor fuel cycle. Commercial scale reprocessing has already been demonstrated for some forms of fuel. However, in order to support a large scale breeder reactor program, new reprocessing technologies will have to be developed for the fuel cycle which is eventually chosen. To be acceptable to society, future reprocessing technology may have to be more resistant to the possibility of diversion of potential weapons material than are present technologies.

It is believed that reprocessing technology can be developed more rapidly than can the breeder reactors themselves. However, delays in establishing this technology could slow the implementation of breeder reactors.

Present usage of thorium is very small. If a thorium-based fuel cycle is chosen, a greatly expanded thorium mining and processing industry would have to be developed. This is not expected to present technical problems, but unforeseen troubles may arise.

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[14] Additional information regarding the factors affecting the possible commercialization dates for the various breeder technologies appears in U.S. Congress. House. Committee on Science and Technology. Subcommittee on Fossil and Nuclear Energy, Research, Development, and Demonstration. Alternative Breeding Cycles for Nuclear Power: An Analysis. Committee Print. Prepared by the Congressional Research Service, Library of Congress. Washington, U.S. Government Printing Office, October 1978. Chapter V. Commercialization of Alternate Breeder Technologies, pp. 45–52.

[15] Opponents of LWBRs question whether they could be called breeder reactors even if a conversion ratio of 1.02 was achieved. Since some fuel is inevitably lost during reprocessing, there would be a net loss of fertile material associated with the operation of LWBRs with their comparatively low conversion ratio, rather than a net gain as with other breeders. This distinction may be artificial, however, as successful operation of an LWBR with a conversion ratio of 1.01 could extend fissionable resources for many centuries, and even a conversion ratio of slightly less than one could allow operation of nuclear reactors for hundreds of years with currently known resources.

B. Economic

A paramount question in the breeder reactor debate is whether the country will want or need a breeder at all. This is partially an economic question. Some experts expect that the capital costs of a breeder reactor will be from 25 to 75 per cent greater than capital costs for a similar sized light water reactor. If these projections are correct, breeder reactors would become economical compared to conventional reactors only if uranium becomes scarce and/or prices rise dramatically. When, and even if, this will occur is dependent upon the growth rate of nuclear power, the extent of future uranium discoveries, other advances in uranium process and utilization [16] and the development of alternate energy sources.

A 1979 DOE study [17] estimated the transition date to an economic breeder reactor under a wide range of assumptions regarding the above uncertainties. The study provides examples in which the transition might occur as early as 1997 and others in which it does not occur until after 2050. Carter Administration strategy is based upon the assumption that breeder reactors will not be economical before 2020.

A separate economic problem which might affect the implementation of breeder reactors is that of the development of the supporting stages of the fuel cycle. Reprocessing technologies and a thorium industry (if that fuel cycle is selected) might be technologically and otherwise achievable, but could lag in development until a commitment has been made to a sufficient number of breeder reactors to make these operations economical. Unavailability of these technologies might in turn limit orders for breeder reactors.

C. Environmental

It appears that the environmental and safety problems associated with the operation of breeder reactors will be similar to those associated with LWRs.[18] However, it is too early to make a detailed analysis of breeder reactor safety features. Safety related problems, which may emerge after commercial plants are built, could hinder the implementation of breeder technology.

D. Social

Social problems relating to nuclear power are discussed in the chapter on Conventional Light Water Nuclear Reactors.

E. Political

Considerable concern has been raised about the danger of nuclear weapons proliferation in connection with the LMFBR fuel cycle. There is concern that terrorists might be able to obtain plutonium for use in fabricating nuclear weapons at some stage during repro-

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[16] Advances in enrichment techniques, introduction of advanced converter reactors, and reprocessing of spent fuel.

[17] U.S. Department of Energy. The Nuclear Strategy of the Department of Energy. Washington, U.S. Government Printing Office, April 1979, 78 p. DOE/ER-0025-D.

[18] U.S. Congress. House. Committee on Science and Technology. Subcommittee on Fossil and Nuclear Energy Research, Development, and Demonstration. Alternative Breeding Cycles for Nuclear Power: An Analysis. Committee Print. Prepared by the Congressional Research Service, Library of Congress. Washington, U.S. Government Printing Office. Oct. 1978, 126 p.

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cessing or fuel fabrication. There is also concern that the introduction of LMFBRs worldwide would increase the number of governments which have access to weapons material. These concerns may ultimately limit the development of breeder reactors which operate on plutonium based fuel cycles. Although some consider the proliferation dangers of reprocessing in thorium-based fuel cycles smaller than for plutonium-based fuel cycles, it is possible that this danger might also ultimately be judged to be unacceptably high.

Sixty-six nations and five international organizations recently participated in an International Nuclear Fuel Cycle Evaluation (INFCE) which was convened by the United States in October 1977 to evaluate the proliferation dangers of the various nuclear fuel cycles. The summary report of INFCE, which was released in February 1980, concluded that no fuel cycle can be made proliferation proof through technical means alone. INFCE further concluded that the proliferation risks of any fuel cycle, taking into account the institutional measures which have been proposed by that body to reduce the risks of proliferation from all fuel cycles, must be balanced against any economic, environmental, energy strategy, and resource utilization advantage that the fuel cycle might have.[19]

Another political obstacle to the early development of breeder reactors is the Carter administration's position that the Clinch River Breeder Reactor Project should be cancelled. It is not clear whether cancellation of CRBRP would actually delay the development of breeder reactors, since some claim that work could then begin sooner on a large breeder reactor which would have to be built in any event.[20] However, the Administration has committed itself only to studies of another breeder reactor demonstration plant, rather than to design and construction.

Congress and the Carter administration have clashed over the future of the breeder reactor since April 1977, when the President announced that because of the dangers of proliferation, he would recommend indefinite deferral of commercial reprocessing and recycling of plutonium, and that there was "no need to enter the plutonium age by licensing or building a fast breeder reactor such as the demonstration plant at Clinch River." Since then, the Administration has favored the cancellation of the CRBRP and redirection of funds to studies of other breeder and advanced converter fuel cycles, as well as to increase uranium enrichment and further exploration for uranium. One of the Administration's main arguments for cancellation of CRBRP is a claim that the pool-type design used in France and the Soviet Union has been shown to be better than the loop-type. Hence, CRBRP, which is a loop-type, is an "obsolete technology." This claim is disputed by proponents of CRBRP.

Despite Administration efforts, Congress has continued to fund CRBRP. However, the political difficulties surrounding the project have contributed to a slippage of its development schedule and to serious uncertainty over its future.

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[19] International Nuclear Fuel Cycle Evaluation. INFCE Summary Volume. Vienna, International Atomic Energy Agency, 1980, 72 p.

[20] Kendrick, Hugh, Acting Director, Nuclear Altrenative Systems Assessment Division, DOE, in remarks at Federal Staff Seminar on Plutonium and Nuclear Power. Georgetown University, May 27, 1980.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

None.

B. Contribution by 2000 or Beyond

It appears that with an aggressive development program, the first commercial breeder reactors could be available shortly after the year 2000. However, if sufficient uranium is still available, it is unlikely that breeders will have an economic advantage over LWRs or advanced converter reactors at that time. Hence, breeder reactors are not expected to contribute significantly to U.S. energy supplies until after the year 2000. Depending on the growth rate of all nuclear power, the extent of future uranium discoveries and other advances in uranium processing and utilization, breeder reactors may be introduced in the United States shortly thereafter or not for several decades. Eventually, if nuclear fission is to remain a long-term energy option, breeder reactors will have to be an integral part of the nuclear fuel cycle.

FUSION *

I. Survey of the Current Situation

In a power plant based on fusion power the fusion reaction would replace the conventional coal/oil fire box or fission reaction as the source of heat used to produce steam for the generation of electricity. However, in contrast to coal, oil, and fission power, the scientific feasibility of fusion power remains unproven.

A. Description of the Technology

Unlike nuclear fission reactors which extract the energy that results from splitting heavier elements into lighter fragments, nuclear fusion reactors would utilize the energy released when lighter elements combine to form heavier elements. Most proposed nuclear fusion power plants are based on the reaction wherein one atom of deuterium and one atom of tritium (both gases, and isotopes of hydrogen) collide and fuse to form an atom of helium. The reaction releases energetic neutrons which are absorbed by and heat the surrounding coolant. The coolant when heated generates steam, which is used to power conventional turbines for the production of electricity. One difficulty in achieving nuclear fusion is heating the fuel mixture of deuterium and tritium to a hot "plasma" state, in which the electrons have been stripped from the nuclei, and the nuclei are colliding with sufficient force to overcome their mutual repulsion, thus enabling fusion to occur. Another great problem in attaining nuclear fusion is the confinement of this plasma at sufficient density for a sufficient duration so that enough reactions take place to return more energy than is used to heat and contain the plasma. The different approaches to fusion may be categorized by the method used to heat and contain the plasma.

1. MAGNETIC CONFINEMENT

For the plasma to remain at the required temperatures, it cannot touch any solid walls or cooler gases. In the traditional design approach, the confinement of plasma is attempted with a magnetic field. Plasmas will freely slide along in the direction of the magnetic field lines but tend not to flow through the lines. Thus, in the magnetic confinement approach, plasma containment is attempted by interposing magnetic fields between the plasma and the walls of an otherwise evacuated chamber.

Magnetic confinement systems fall into two basic categories: open-ended and closed systems. The most advanced open-ended system is the magnetic mirror scheme, so called because in this configuration the magnetic field lines close together and intensify toward the ends. Thus, charged particles moving toward the ends, where the field strength is highest, are reflected back toward the

* Prepared by Lani H. Raleigh, specialist in aerospace and energy systems.

middle. The particles may be reflected back and forth numerous times before they escape.

Another plasma confinement scheme is the closed toroidal system. This design attempts to improve plasma confinement by bending the plasma column into a torus, thus eliminating the ends. The tokamak, a doughnut-shaped tube inside of which hot plasma is contained by magnetic fields, and its variations are, to date, the most successful magnetic confinement devices.

Generally, in magnetic containment schemes fuel would be introduced either continuously or periodically into the reaction chamber where it would be heated and compressed into a dense plasma to produce fusion. The flux of energetic neutrons, which are a product of the reaction, would heat a coolant, such as molten lithium, flowing within the walls of the reaction chamber. The heated lithium would then be passed through a heat exchanger where it would generate steam to power a conventional turbine generator.

2. INERTIAL CONFINEMENT

Inertial confinement represents an entirely different approach to designing nuclear fusion reactors. The basic concept involves focusing a short burst of high energy laser light or charged particle beam onto a minute pellet or a glass microsphere containing a deuterium-tritium (D–T) gas mixture. The energy of the laser light or particle beam, striking and heating the outer layer of the pellet, causes it to explode. This explosion of outer surface layer material drives the remaining contents of the pellet inward, creating an extremely dense, hot core region where fusion reactions occur. Theoretically, this inward thrust will eventually result in inertial confinement of the plasma for a sufficient length of time to allow a significant number of fusion reactions to occur.

Design proposals for inertial confinement reactors include a large spherical reaction chamber with very strong walls. Fuel pellets would be exploded in the reaction chamber at the rate of one or so per second. As in the magnetic containment schemes, heat would be generated in the molten lithium coolant by the capture of reaction neutrons. The heat from the lithium would be used to produce steam to power a conventional turbine generator.

3. OTHER FUSION ENERGY TECHNOLOGIES

(a) Synthetic fuels.—Efforts are underway to develop a method to use fusion neutrons to produce methane, the principal ingredient in natural gas. The neutrons produced in a fusion reaction would be used to break down water molecules into their constituent elements, hydrogen and oxygen. If hydrogen could be produced cheaply, it could easily be converted to methane which could be fed directly into the natural gas distribution network as a substitute natural gas.

(b) Fission-fusion hybrid.—The D–T fusion reaction releases an exceptionally energetic neutron (14 megaelectronvolts) that will be used in a lithium blanket to generate the tritium atom consumed in the reaction. These neutrons could also be used to breed plutonium from uranium either in a cooling blanket or in a reactor core surrounding the fusion reaction. Such a concept is called a "hybrid".

B. Known Resources and Reserves

Ideally, a fusion reactor could operate on a deuterium-deuterium reaction. However, since ignition of a D–D reaction is difficult, present first-generation reactor designs are based on the easier to ignite deuterium-tritium reaction. A fusion plant operating on a D–T cycle would be limited by the availability of lithium with which to breed tritium. Initial estimates indicate that reserves of high quality lithium ores and lithium salts would be sufficient to operate fusion plants for several thousand years.

Recently, however, concern has surfaced over the relatively small rate of current lithium production and the increasing demand for this versatile, light metal. Lithium already has a variety of industrial uses and shows great promise in new types of storage batteries. Unless lithium exploration is expanded and production is increased, those seeking lithium for use in fusion plants will have to compete with other buyers to obtain the limited supplies.[1]

The supply of deuterium, the other half of the D–T fuel used in fusion plants, is virtually unlimited. A portion of all natural hydrogen is actually the heavier deuterium and is readily separated from seawater. Thus, the world's oceans could supply fusion fuel for many thousands of years.

One resource, which is unrelated to fusion fuel requirements, but essential for some fusion devices, is helium. Helium has unique physical properties. It is the only element which does not solidify at temperatures approaching absolute zero (−273 C); it has excellent heat transfer properties; it is transparent to radiation; and, it does not become radioactive. In fusion devices, helium may be used to cool lasers and large superconducting magnets. It is also a candidate reactor coolant.

Helium is found in the atmosphere and in natural gas deposits. When natural gas is processed for fuel, helium is lost to the atmosphere unless it is extracted for use or stored. Each year nearly 13 billion cubic feet of helium escape into the atmosphere. Currently, helium conservation legislation requires the Federal Government to provide for Federal agency needs only. Some fear that as natural gas supplies dwindle, and as helium-dependent energy technnologies grow in importance, there will be a shortage of the resource unless the Federal Government assumes responsibility for conserving helium to meet future needs. Technically, there remains the possibility of atmospheric extraction, but this method is exorbitantly expensive, $2000 per thousand cubic feet, compared to $13 per thousand cubic feet for recovery from natural gas.[2]

C. Current Contribution to U.S. Energy Supplies

Fusion currently makes no contribution to U.S. energy supplies.

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[1] I. Y. Borg and L. G. O'Connell, "Lithium's Role in Supplying Energy in the Future", Energy Sources, vol. 2, No. 4, 1976.

[2] General Accounting Office. Unique Helium Resources Are Wasting; A New Conservation Policy Is Needed. U.S. Government Printing Office, Washington, D.C., March 7, 1979, 98 p.

D. State-of-the-Art

No fusion scheme has demonstrated scientific feasibility, or ability to produce as much energy as is consumed in the process.

E. Current Research and Development

1. MAGNETIC CONFINEMENT—U.S. PROGRAM [3] [4]

The majority of magnetic confinement research and development is funded by the Department of Energy (DOE) and performed by the major Federal research laboratories, the private sector, and universities. Magnetic confinement research is focused on the major plasmas physics and technical/engineering problems which must be solved before commercial fusion power is a reality. Areas of research include: plasma physics research associated with heating and confining hot plasmas; efforts to develop materials which will withstand intense radiation; development and fabrication of durable, less expensive superconducting magnets and magnet shields; research to determine the compatibility of candidate reactor coolants with containment materials; methods to contain radioactive tritium; and the development of reactor designs which will allow sufficient access and maintainability to be commercially viable.

These problems are approached through fundamental research, and the design, fabrication, and operation of proof-of-principle experiments. Emphasis is placed on the tokamak and mirror fusion devices, since they are the most advanced and show the greatest promise of proving scientific feasibility. There is, however, a concurrent development of alternate magnetic confinement devices which have features that may make them more attractive for commercial operation.

Currently, there are numerous small-scale, proof-of-principle devices which are used to improve theories of plasma behavior, to demonstrate the effectiveness of various experimental heating schemes, and to test various reactor components. The next step is to build increasingly larger devices to determine the effects of scaling on plasma performance. The two major scaling experiments in the area of magnetic confinement are the Tokamak Fusion Test Reactor (TFTR) and the Mirror Fusion Test Facility (MFTF-B).

The Tokamak Fusion Test Reactor (TFTR) will be the largest tokamak in the United States. It is expected to produce fusion energy at the energy breakeven level, using a deuterium-tritium (D-T) plasma. It will be used to study the physics of burning plasmas and the engineering aspects of D-T tokamak operations with power densities near those required for a commercial reactor. It will be the first fusion device to explore the engineering requirements of remote maintenance, since the use of tritium will lead to low-level contamination of some device components. Located at the

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[3] Authorizing Appropriations for the Department of Energy (DOE) for Fiscal year 1980. U.S. Congress, House Committee on Science and Techonolgy. House Report 96-196, pt. 3; 96th Congress, 1st sess., May 15, 1979, pp. 155-97.

[4] 1980 Department of Energy Authorization. Hearings before the House Committee on Science and Technology, Subcommittee on Energy Research and Production. Vol. III, 96th Congress, 1st sess., Feb. 27, 28, Mar. 2, 1979; pp.1-94, 363-438.

[5] Energy and Water Development Appropriations for 1980. Hearings before the House Committee on Appropriations. Pt. 5, 96th Congress, 1st sess.; Mar. 8, 1979, pp. 511-1050.

Princeton Plasma Physics Laboratory, the TFTR is scheduled for completion by March 1982 and is expected to cost $290 million. Experiments on the TFTR are expected to provide the critical physics and technology data base from which a tokamak prototype reactor could be developed.

The Mirror Fusion Test Facility (MFTF-B) is expected to be a major step in exploring conventional mirror characteristics under reactor-grade plasma conditions. The principal purpose of the MFTF is to provide a large-scale tandem magnetic mirror device and supporting facility for performing physics experiments and technology development needed to bridge the gap between smaller existing tandem mirror experiments and a mirror fusion experimental reactor. Located at Lawrence Livermore Laboratories, the MFTF-B is expected to be completed by 1984 or 1985, for an estimated cost of $225 million.

2. MAGNETIC CONFINEMENT—FOREIGN EFFORTS [6]

The four major magnetic confinement fusion programs are those of the United States, the Soviet Union, the European community (England, France, West Germany, Italy), and Japan. All four major magnetic fusion programs emphasize the tokamak and each nation has now embarked upon a major confinement device. The Soviet program is broadly based, but, as in the United States, there is strong emphasis on tokamak research. The Soviet T-15 facility (1982-83) will be roughly the same size as the U.S. TFTR, but it will utilize for the first time a set of large superconducting magnets which will extend its pulse length capability. Perhaps the largest Soviet project is the T-20 tokamak. Although the plans for this device are in an evolutionary state, it is expected to be larger than any of the devices currently planned for operation in the mid-1980's.

Members of the Commission of the European Communities (Euratom) are combining efforts to build a $240 million Joint European Torus (JET). The JET, scheduled for operation in 1984, will have many times the plasma volume of the TFTR. Also, the capability for limited deuterium-tritium burning could be added to JET in the late 1980's.

The Japanese JT-60 (1982), larger than the TFTR, will not use tritium but will have additional experimental flexibility, including a divertor for removing impurities and the capability of shaping the plasma cross-section.

Aside from these major efforts, fusion programs also exist in Argentina, Austria, Australia, Belgium, Canada, Egypt, the Federal Republic of Germany, France, Italy, Japan, Mexico, the Netherlands, Portugal, Spain, South Africa, and Sweden with lesser efforts in Brazil, Czechoslovakia, Denmark, Israel, Poland, Switzerland, and the People's Republic of China.

There is significant exchange of scientific personnel and data among those nations conducting fusion research. Much of this scientific exchange is through the auspices of the International Atomic Energy Agency (IAEA), the Internatonal Energy Agency (IEA), and the Joint Fusion Power Coordinating Committee (JFPCC). The international cooperative programs include short

[6] Public Works for Water and Power Development and Energy Research Appropriations for fiscal year 1979. Hearings before the Senate Committee on Appropriations. Pt. 4; 95th Congress, 2d Sess. Mar. 13, 1978, pp. 475-607.

visits and seminars, long-term working visits, basic plasma physics theory experiments, and many aspects of joint technology development in such areas as materials for fusion reactors, large superconducting magnet systems, and plasma-wall interactions. Currently under discussion is a proposal by the Soviet Union to build an International Tokamak Reactor (INTOR) which would be the next step beyond the various tokamak machines now under construction. The purpose of such cooperative efforts is to allow each nation to obtain the benefits of the backup programs pursued by the others to provide a broad base for future development without unnecessary duplication.

3. INERTIAL CONFINEMENT—U.S. PROGRAM [7] [8]

The Department of Energy (DOE) funds the majority of inertial confinement fusion research and development. The primary goal of this effort is weapons technology applications and the secondary objective is the development of a means of commercial power generation. As in the magnetic confinement program scientific feasibility has not yet been demonstrated.

Essential to the achievement of scientific feasibility are the development of a driver with durability, high efficiency, high energy, high repetition rate, and short pulse length, and the fabrication of a target (pellet) which can reach thermonuclear burn. There are currently a number of experiments which are used to test various driver technologies and targets.

The major experiment expected to achieve scientific feasibility is the Nova neodymium glass laser, scheduled for operation by the mid 1980s. Ten laser beams will be focused onto a minute target to which 100 kilojoules of energy will be delivered in a billionth of a second at a peak power of 100 terawatts. Nova, which will cost approximately $137 million, will be located at Lawrence Livermore Laboratory in California.

The glass laser at Nova was chosen for this major scaling experiment because it is currently the most advanced driver and can therefore be completed sooner than other driver designs. Neodymium glass lasers are ideal candidates for military applications because they are an available technology and exceedingly flexible in terms of power and pulse duration. Civilian applications, however, place much more stringent requirements on a driver, requiring high efficiency, high repetition rate and long lifetime. Thus, in parallel with the effort to demonstrate scientific feasibility with the Nova, other driver technologies, such as gas lasers and charged particle beam devices, are under active development. The major scaling efforts utilizing these driver technologies are the Antares High Energy Gas Laser and Electron Beam Fusion Accelerator experiments.

The Antares 100 kilojoule carbon dioxide laser will be located at Los Alamos Scientific Laboratory, Los Alamos, New Mexico. The facility will cost $63 million and be operational by early 1984. The

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[7] Department of Energy Authorization Legislation (National Security Programs) for Fiscal Year 1980. Hearings before the House Committee on Armed Services, Subcommittee on Procurement and Military Nuclear Systems, 96th Congress, 1st Sess. Feb. 14, 15, 16; Mar. 5, 7, 21; Apr. 9, 1979, 861 p.

[8] Information also provided by the Office of Inertial Fusion, Department of Energy.

laser system will consist of six power modules which will form 72 beamlines. It is expected to eventually achieve energy breakeven.

Construction of the Electron Beam Fusion Accelerator (EBFA) at Sandia Laboratories, Albuquerque, New Mexico, is now nearing completion. The EBFA will generate 36 beams of electrons or light ions at a power level of 40 million watts. The facility cost $15 million and experiments are scheduled to begin in mid 1980. The design of the facility will permit the power level to be increased two or more times by doubling the number of beamlines, if this is warranted by the results of the initial experiments.

4. INERTIAL CONFINEMENT—FOREIGN EFFORTS [9]

The Soviet Union, Japan, Great Britain, France, West Germany, Canada, the People's Republic of China, Israel, Argentina, and Spain have inertial confinement fusion programs. Of these the Soviet and Japanese programs are the largest.

Although the Soviets are pursuing some laser fusion devices, they are emphasizing particle beam fusion experiments. They have started construction on the Angara-5 electron beam machine. When completed, it will have 48 electron beam generators and is supposed to surpass breakeven.

The Japanese also have a large inertial confinement fusion program. They are actively investigating glass, gas, and particle beam driver technologies. Their major device is the Gekko 10 kilojoule glass laser.

Other foreign programs consist of small experiments and research efforts to study plasma physics and target development.

II. PROSPECTS OR REQUIREMENTS FOR FURTHER DEVELOPMENT

A. Research and Development

Fusion power is regarded as a long term energy resource. At present the development strategy of the Department of Energy (DOE) for fusion power includes proving scientific feasibility, constructing demonstration reactors, and initiating commercialization efforts.[10] Scientific feasibility is defined as the extraction of as much energy from fusion reactions as was provided to induce the reactions. In magnetic confinement, scientific feasibility is expected by 1983–84. In inertial confinement, DOE predicts that demonstration of scientific feasibility will occur by 1985–86.

After scientific feasibility has been demonstrated, the program will move from applied research into a development phase. According to the DOE program plans, Engineering Test Facilities (ETFs) will be constructed by the mid 1990s for the more promising designs in both magnetic and inertial confinement. These facilities will be integrated systems producing net energy gain using fusion plasma techniques developed in the previous generation of experimental devices. The ETFs will also establish the technological and engineering requirements of each of the major components of a prototype reactor.

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[9] Ibid.

[10] Energy and Water Development Appropriations for 1980. Hearings before the House Committee on Appropriations. Pt. 5, 96 Congress, 1st sess. Ma. 8, 1979, pp. 511–1050.

B. Demonstration

Demonstration, the next phase of the DOE program, will involve the operation of an Engineering Prototype Reactor (EPR). The EPR will combine the elements tested in the superior ETF in a pilot plant which will approach for the first time complete energy gain, where the energy produced exceeds all energy consumed in keeping the entire plant running. The EPR will also be designed to operate with a plant availability near that of conventional power plants. It will also demonstrate a reactor-scale tritium fuel cycle with breeding modules, a high termperature blanket system, and reactor plant maintenance and safety systems. Demonstration will be completed with the construction of one or more commercial demonstration reactors (DEMOs), in which a net power gain in excess of 100 megawatts per plant will be achieved. The objective of a DEMO is to demonstrate safe and reliable electrical power generation at a near-commercial scale in a utility environment providing the technical and economic groundwork to allow private industry to decide on the rate at which fusion power plants can be commercially introduced.

C. Commercialization

From the date of the successful operation of the EPR, DOE estimates that another 20 years will be required before fusion energy reaches its Initial Operating Capability, or commercialization stage, defined as production of power equivalent to three or four 1000-megawatt powerplants. During this last stage of development, significant private investment is anticipated, although a strong Federal role will probably be necessary to facilitate the transfer of the technology from the public to the private sector. Current expectations are that the Initial Operating Capability stage will be reached between 2020 and 2030.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

Both magnetic and inertial confinement approaches to fusion have a host of theoretical and engineering problems that must be solved before fusion becomes a practical energy resource. There is a high level of confidence among fusion experts that the physics of a fusion reactor can be conquered and scientific feasibility can be proved.[11] Perhaps the more formidable task at this point is the technical and engineering research needed to develop a reactor which will demonstrate commercial feasibiltiy. Commercial viability will depend to a large extent on the development of materials which are not expensive and can withstand intense radiation, the ease with which component parts can be fabricated, and the reliability and maintainability of a given reactor design.

[11] See for example: Harold P. Furth, "Progress Toward a Tokamak Fusion Reactor", Scientific American, September 1979, pp. 50–61; Arthur L. Robinson, "Fusion Energy in Our Time", Science, Feb. 8, 1980, pp. 662–624; Department of Energy, "General Characteristics and Assessment of the Scientific/Technical Feasibility of the Next Major Device in the Tokamak Fusion Program: Summary of the U.S. Contributions to the INTOR Workshop", September 1979, 13 p.; Atomic Industrial Forum, "Fusion Energy at the Crossroads: Role of the Private Sector", Dec. 31, 1979, 12 p.; as well as the reports of the DOE Fusion Power Coordinating Committee and the Fusion Power Associates.

B. Economic

Since there as yet no final plans for an operating commercial fusion reactor, the economic costs of a fusion plant are, at present, speculative. Nevertheless, cost estimates of various potential reactor components may be valuable to the extent that they indicate a general order of magnitude and may be helpful in identifying areas in which more basic research is needed to develop cost-reducing technologies. One such area is materials research to develop materials which will withstand the intense radiation environment of a fusion reactor and will therefore need replacement less often. Other factors which will impact on fusion economics are reactor size, availability, and maintainability, as well the construction time required to assemble the various fusion plant components.[12]

C. Environmental

Fusion power generation is expected to involve a minimal hazard from nuclear by-products. Tritium gas, which would be collected from the lithium coolant for use as fuel, has a low energy beta radioactivity and a short half-life (approximately 12.5 years). It is therefore not as hazardous as radioactive plutonium-239, iodine, strontium, cesium, or many other fission by-products.

Nevertheless, since all radioactive elements must be considered ultimately harmful, measures which protect the environment against their distribution must be taken. Tritium is potentially harmful because it is a light gas and spreads rapidly, and because it can replace hydrogen in molecules such as water and be easily ingested by humans. It does not, however, concentrate in any body tissue and is eliminated from the human system in 5 to 12 days.

Another environmental consideration involves the reactor vessel itself. Since the neutrons in the D-T reactions are very energetic and will cause the reactor structure to become radioactive after several years of operation, there is a problem of structure disposal or storage. Current efforts to develop materials which are more impervious to tritium and intense neutron fluxes may reduce the environmental problems of tritium release and disposal of radioactive materials.

D. Social

The major social issue concerning fusion power, other than the uncertainties typically associated with the employment of an unknown technology, relates to the centralized vs. decentralized energy debate. Because of their large size and expense, nuclear fusion power plants will necessarily be centralized energy sources. Those who are philosophically opposed to an energy policy based on centralized energy sources may, therefore, object to the widespread implementation of nuclear fusion power.

E. Political

One of the political issues regarding fusion development concerns the pace and funding of the program. With development costs that

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[12] See D. A. DeFreece, "Fusion Energy Economic and Commercialization Trade-Offs", EPRI Executive Seminar on Fusion, Oct. 11–13, 1977, San Francisco, Calif., reprinted in "A Feasibility Study for Enhancing the Development of Fusion Energy", Electric Power Research Institute (EPRI), EPRI ER-788-SR, March 1979, 150 p.

will be measured in billions of dollars and no immediate return on investment, fusion research has not attracted much private sector support and is therefore funded almost entirely by the Federal Government. Thus far, the Federal Government has spent $686 million on inertial confinement fusion and $2 billion on magnetic confinement fusion. The fiscal year 1980 appropriations for magnetic confinement program total $355 million; the inertial confinement fusion appropriations total $192 million. It is estimated that another $14 to $16 billion must be spent before commercial fusion power will be demonstrated.

In the magnetic confinement program there is an on-going debate as to whether the pace of the program should be significantly accelerated with greatly increased near-term funding levels. Opponents argue that the tokamak design is the only design which is sufficiently advanced to be accelerated, and that its accelerated development will foreclose other alternative designs which are more commercially attractive. Proponents argue that accelerating the development of the tokamak will yield findings valuable to all magnetic confinement fusion approaches. In addition, they point out that the Department of Energy has developed a strategy whereby a demonstration reactor could be built by 1995 without foreclosing any promising alternative concept. Furthermore, although near-term funding would have to be increased by 100 percent for such an accelerated approach, an overall cost reduction of approximately 15 percent would be achieved by shortening the period of time required for technology development, thereby minimizing the effect of steadily rising costs and inflation. Despite such arguments, it may be difficult to convince the Congress in a period of high inflation to significantly increase current appropriations for such a long-term energy resource.[13]

In the inertial confinement program, the primary goal of current research efforts is weapons technology applications and the secondary goal is commercial power generation. Proponents justify this approach on the basis that at this point in the development of the technology, both the military and civilian applications require the development of fundamental fusion physics which will lead to demonstration of scientific feasibility. Critics of the program claim that the considerations for military and civilian applications are sufficiently distinct that the program should be divided, in order to prevent the pursuit of military goals from retarding progress toward the development of a commercial power reactor. Thus far, all funding for inertial confinement fusion programs has been included in the defense activities portion of the DOE budget. The issue of civilian and military applications research in the inertial confinement program promises to be of increasing interest as research in this area progresses.

F. Institutional

The lack of large-scale utility involvement in fusion research may lead to commercialization problems unless utility interests are considered in current planning. Generally, the utilities are beset with near-term problems of higher urgency than those associated

[13] See Arthur L. Robinson, "Fusion Energy in Our Time", Science, Feb. 8, 1980, pp. 622–24.

with a 21st century technology. Development lead times will, however, make it necessary to commit the program, in the next several years, to decisions that will strongly influence the nature and feasibility of future power plants. Although heavy industry involvement in fusion at this point would be premature, an appropriate means of increased utility participation will be needed if the industry viewpoint is to be included in such decisions so that fusion power would evolve in a form which is acceptable to its ultimate customer—the utility.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Fusion is not expected to make any contribution to U.S. energy supplies by 1990.

B. Contribution by 2000 or Beyond

Under the Department of Energy program strategy, fusion power will not make significant contributions to U.S. energy supplies until at least 2040.

SYSTEM EFFICIENCY TECHNOLOGIES

COGENERATION *

I. Survey of the Current Situation

A. Description of the Technology

Cogeneration is the process of applying the steam from a single boiler to two separate uses such as power generation and process heating. The term, as commonly used today, has been broadened to include the application of waste heat from a power generating facility. The waste heat may be used for any suitable purpose e.g. comfort heating or additional power generation (bottoming cycles).

B. Known Resources and Reserves

N.A.

C. Current Contribution to U.S. Energy Supplies

According to the Department of Energy [1] the use of cogeneration in the United States accounted for about 5 percent of the power generated in 1974, down from 15 percent in 1950. Five percent of the power generated in 1974 was about 100 billion killowatt hours. The annual fuel savings realized from these cogeneration systems is unknown, but could have been between 10 million and 20 million barrels of oil equivalent per year.

D. State-of-the-Art

The generation of sufficient steam from a single source to generate electricity as well as supply thermal energy for another process is an old and proven practice. However, new approaches which take advantage of both the high and the low ends of the temperature range are in the research or introductory phases.

Magnetohydrodynamics (MHD), discussed in another section, is in the research phase as a topping cycle. At the lower end of the heat spectrum, waste heat utilization systems are being introduced in which fluids having a low boiling temperature are vaporized and applied to power turbines, then recondensed and recycled.

E. Current Research and Development, Demonstration Programs and Commercial Development

The Department of Energy fiscal year 1981 budget request [2] includes the announcement that an inventory is being prepared which will list all potential industrial cogeneration sites in the

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* Prepared by George Chatham, specialist in aeronautics and space.

[1] Cogeneration: Technical Concepts, Trends, Prospects. U.S. Department of Energy, DOE-FFU-1703, September, 1978. Washington, D.C.

[2] Department of Energy Congressional Budget Request, fiscal year 1981, vol. 7, January 1980. "Energy Conservation." p. 579.

United States. These sites will cover a wide range of systems, temperature conditions and needs for cogenerated steam or electricity.

The same request listed the various demonstration programs and design studies the department has underway to make available systems appropriate to the variety of opportunities their inventory will disclose. Both "topping" and "bottoming" cogeneration systems are under development. In a topping cycle, the secondary or cogeneration system is placed between the heat source and the primary system. In a bottoming cycle, the primary system receives the energy first and the secondary or cogeneration system operates from the remaining energy discharged by the primary system.

Topping cycles under development include:

(1) *Magnetohydrodynamic electrical generation.* This technique is described in another section of this report.

(2) *Thermionic conversion.* Metals such as tungsten coated with thorium become rich emitters of negatively charged ions when heated to temperatures over 1500° F. Another cooler metal surrounding such an emitter becomes a "collector" and a useful flow of electricity is generated. Thermionic devices are being tested which serve as burners and may replace the conventional burner systems in fossil fuel boilers. These new converter units have the potential of raising the efficiency of a power plant from the average 33 percent to about 45 percent.

(3) *A diesel-electric generator* rejects about 70 percent of the energy it consumes as waste heat. As a topping cycle, the diesel can supply its waste heat to a low pressure boiler. When used to power a steam turbine-generator, overall plant efficiency can be raised by 10 percent or 15 percent.

(4) *A high temperature gas turbine* is being constructed to serve as a topping cycle. Since the combustion process occurs outside the turbine, it is relatively insensitive to the type of fuel used in comparison to the internal combustion diesel. The turbine, driven by combustion gas, will generate electricity and then exhaust the gas to serve as a heat source for a primary boiler. This method will raise the overall plant efficiency by 10 percent to 15 percent.

Bottoming cycles make use of the energy remaining in steam after it has done its primary job. Should this energy residual be inadequate for the desired bottoming cycle, the initial temperature or quantity of steam may be increased to insure that the energy content is adequate. Development and demonstration projects for two types of bottoming systems are underway:

(1) *Rankin systems* extract mechanical work from fluids which boil into gas at low temperatures. Refrigerants such as ammonia or freon absorb the energy from the residual steam and undergo rapid boiling producing vapor under sufficient pressure to drive a low pressure turbine generator. The gas is then condensed and pumped back to the heat exchanger where it is recycled.

(2) *Brayton systems* operate in a similar fashion to the Rankine but use only a gas as a working medium. The gas, such as helium is expanded as it receives heat in the heat exchanger, thence drives a low pressure turbine where it loses much of its heat and volume. The cooler gas is then recycled through the heat exchanger to be re-expanded.

Since bottoming cycles extract work from energy that would otherwise be rejected, they can increase the overall efficiency of the plant by 10 percent or more.

II. Prospects or Requirements for Further Development

A. Research and Development

In addition to the systems described on the first section, design effort has begun on a multi-fuel diesel and an advanced high temperature gas turbine. The objective in both cases is to achieve greater flexibility in choice of fuel.

The sale of process steam by an electrical utility is not widely practiced but has a history going back to the early part of the century. It is the only method of cogeneration which has gone beyond the research and development stage.

1. CAPITAL

The total federal investment for cogeneration research and development in fiscal year 1981 is $25.87 million, a sum which includes $2 million for thermionics. This is approximately a 34 percent increase over fiscal year 1980. However, according to the Department of Energy, the fiscal year 1981 budget could be sharply reduced as part of the overall effort of the President to reduce the budget.

2. TIME

Testing for the purpose of gathering operational data is underway for the Brayton and Rankine bottoming cycles, the diesel waste heat low pressure boiler system and the thermionic topping cycle. Technical and economical analyses of these systems will lead either to their rejection or to the design and construction of full scale demonstration units which could serve as prototypes for commercial production. With continued effort the commercial prototype phase for successful candidates will require from 2 to 5 years.

Other, more advanced cogeneration cycles such as MHD and the high temperature gas turbines, either of which might be combined with thermionic conversion systems are in either the design phase or laboratory testing. Working trial systems may appear within 12 to 24 months.

3. MANPOWER

Manpower is not critical variable to cogeneration systems, either in the research, demonstration or practical application phases. In full scale use, a power plant employing a cogeneration unit to increase it efficiency is expected to need less fuel, perhaps 25 percent less. Constant operation at this enhanced efficiency could actually reduce the fuel transportation work load. In the case of bulk fuels such as coal, power plant cogeneration could reduce the manpower requirements of the coal supplier.

B. Demonstration

Although trials of test articles are often called demonstrations, the cogeneration systems now in various stages of development have not yet reached the commercial prototype demonstration phase.

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1. CAPITAL

Federal expenditures for demonstrations of emerging cogeneration technologies will depend more on budget priorities within DOE than on the technologies themselves. For example, a continued rise in fuel prices, resulting in increasing consumer utility rates may bring about a higher priority to bring cogeneration on stream. Conversely, a lowering of fuel costs could shift the DOE emphasis away from cogeneration.

The cogeneration budget is at present one of the smaller DOE expenditures. An overall cut in the total budget could also reduce or eliminate smaller programs in the interest of protecting those having a higher priority.

Moderate success in the programs now underway, funded at a constant level, may be expected to achieve commercial prototype demonstration within the time frame discussed, or in most instance, within 5 years.

2. TIME

Demonstration of a commercial prototype requires a minimum of a year. After a successful year, lifetime expectation is still a question. if the demonstration involves only a few systems, prospective users will likely want much longer test periods. If many units are demonstrated a better statistical expectation of failure rate can be made and a shorter test period becomes more acceptable.

3. MANPOWER

Manpower is not a variable of importance in the demonstration of cogeneration technologies.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

The physical principles of obtaining more useful work from an energy source through cogeneration techniques are well understood and universally accepted. Without regard to economics, cogeneration methodolgy offers a technical challenge only in the category of material durability at elevated temperature. Bottoming cycles, which operate on low temperature rejected heat tend to be bulky for the work they produce. Their size may challenge the ingenuity of the designer to hold down costs but they operate in a relatively benign environment. Topping cycles on the other hand, call for elevated combustion temperatures for efficient operation.

(1) *Hot gas turbines* are in the design phase which can operate from internal combustion, using gas reformed from coal or external combustion. External combustion turbines are desirable becasue they are insensitive to the type of fuel being used.

The hot gas turbines are similar to conventional gas turbine engines used to augment generating capacity during peak load periods. However, a cogenerators, these turbines are expected to operate continuously, at higher temperature and on gases which may be less pure than that supplied to the conventional turbines used for peak load conditions.

(2) *Magnetohydrodynamics (MHD).* Conventional generators work on the principle that a flow of electricity will emerge from a conductor when it is moved through a magnetic field. In MHD a super heated stream of combustion gas is directed through a magnetic field (see section on MHD). The hot gas, seeded with a vaporized metal such as cesium, serves as the moving conductor. Electricity is drawn from this conductor through plates on the wall of the duct channel.

MHD is well suited as a topping cycle since the hot gas discharge can be applied to operate a primary steam-generator system. However, economy requires that the vaporized metal ions seeded into the gas be condensed or otherwise removed for re-use. Also the channel through which the hot gas is jetted must carry the gas for an acceptable lifetime without severe degradation of the walls or collector plates exposed to erosive effects of the gas. Both of these problems are difficult design and material challenges which are not as yet resolved.

(3) *Thermionic conversion,* the principles of which were explained earlier, requires only a high temperature to work. It has no moving parts and no hot gases are jetted through it. The completely passive nature of thermionic converters greatly reduces the technical challenge compared to other high temperature alternatives. These devices are therefore the most likely candidates to be the first to emerge from the research and testing phase. A test run of 5,000 hours has been contemplated by Rasor Associates under a DOE contract. Examination of the thermionic converters showed no degeneration of the hot side, although a copper weld had eroded on the cooler end of the device. If DOE wishes to resume the testing, a nickel alloy will be substituted for the copper weld. Should a satisfactory lifetime be achieved, the thermionic converters would be considered ready for a commercial demonstration phase.

B. Economic

The decision by a utility to sell process steam, on the decision of a plant operator who makes his own steam to add a generator so that he can also make his own electricity, are straghtforward engineering matters which do not require research. The economics of these types of cogeneration is determined on a case-by-case basis for existing facilities.

High fuel costs and costly electricity have become motivating factors to apply the principles of cogeneration in designing new plants. Planning for the use of cogeneration is also a factor in locating a new facility. In all cases, the energy savings are balanced against costs for the individual situations. A general rule is that in any situation suitable for cogeneration, it can save fuel or reduce the cost of electricity or both. This saving is weighed against equipment cost and where applicable, costs of operation as well as the expected lifetime of the equipment to which the cogeneration devices are to be added. A "pay-back" time is then computed, which indicates the economic merit of the investment.

The cogeneration techniques now being developed, namely the topping and bottoming cycles to increase or augment electrical generation, will be also be subjected to "pay-back" analyses. In electric utility applications as well as industrial, commercial acceptability depends heavily on lifetime and reliability as well as cost.

(1) *Bottoming cycles* are energized by rejected heat or at best, low temperature steam. There is no particular engineering challenge in these systems associated with a stressful operating environment. However, these machines must produced useful work by converting low grade, diffused, energy sources. The penalty associated with the use of diffused energy sources is size. The economic challenge of the bottoming cycles is their bulk. Their purchase price and installation cost, weighed against the value of the fuel they save will be the primary "pay-back" considerations in the commercial application of the bottoming cycles.

(2) *Topping cycles* operate best at very high temperatures. They see the first heat of the system and their exhaust contains the energy to power the primary system. Long term reliability in such an operating environment is an engineering challenge from the design standpoint as well as construction materials.

The economics of topping cycles will rest heavily on lifetime and reliability rather than on initial investment. Topping systems are small and compact compared to bottoming units because the energy they receive is highly concentrated. Initial costs may be less for topping cycles although the costs for cycles of either type is uncertain at the present phase of development.

(3) *Market size* influences equipment selling price because it determines the degree to which a manufacturer can depart from hand made units and move toward mass production. A survey of all types of industrial cogeneration opportunities is being conducted by the Department of Energy at the present time. This market is expected to be larger than the electric utility market, perhaps by several times.

The electric utility market, in terms of retrofit, could include about 2,700 generating plants out the total of 3,060 now in operation. Even if we assume an industrial market ten times the size of the utility market, the numbers of units are far too small for mass production. It is therefore a safe assumption that equipment for any type of cogeneration will involve low production manufacturing methods and much custom designing. Although these low production procedures result in more costly equipment, it is in keeping with the way power plant boilers, generators and large industrial machines are marketed.

C. Environmental

All cogeneration methods are intended to increase the useful yield of energy consuming systems. The net effect is to reduce fuel consumption for a given yield. If fuel consumption is reduced, combustion effluents are also reduced. Since no new effluents or by-products are generated by cogeneration equipment, the effects on the environment are either benign or favorable.

D. Social

Possible reductions in fuel consumption are not so great that fuel production or transportation on the employment of these industries and services would be significantly altered. Social impacts from the use of cogeneration systems are therefore either non-existent or intangible.

E. Political

Local and State regulations which grant monopoly to electrical utilities or stipulate that their sole activity be restricted to the sale of electricity hamper the use of cogeneration in some instances. For example, a prospective industrial cogenerator may not be permitted to generate his own electricity or sell his surplus to the utility. Similarly, a utility might not be permitted to enter into the business of selling process steam, or selling steam waste for the purpose of distinct heating.

Generally, these institutional barriers to cogeneration are old and may no longer serve the purpose originally intended. They can be changed and, though political forecasting is notably perilous, it would seem that in most cases they probably will not seriously impede otherwise beneficial cogeneration efforts.

IV. Potential Contribution To Future U.S. Energy Supplies

A. Contribution by 1990

A nominal increase in a utility plant efficiency which could be credited to a cogeneration installation is 12 percent. Since the efficiency of the plant before cogeneration ranged between 33 percent and 36 percent, the 12 percent increase means an increase in power generation of one third. Or, with the power generation held constant, the cogeneration system could effect a 25 percent reduction in fuel usage.

Nationwide, the generation of electricity is expected to consume between 17 and 18 quadrillion Btu (Q) in 1980.[3] A 25 percent reduction would mean the saving of about 4.5 Q or 800 million barrels of oil equivalent per year.

By 1990, projections of fossel fuel used for electrical generation are between 45 and 50 Q.[4] Using the same calculation procedure, cogeneration could save about 12 Q or about 2 billion barrels of oil equivalent per year.

Although these calculations show the ultimate power plant potential for fuel conservation, they do not reflect the fact that cogeneration systems are not as yet ready for application. With continued development success, the Rankine and Brayton bottoming cycles as well as the thermionic topping cycle could be ready for or well into their commercial demonstration phase by 1985.

Any projection of the market penetration and fuel conservation by 1990 of cogeneration systems must be made without knowledge of their overall economic merit. However, the General Accounting Office has projected a range of 0.26 Q to 1.52 Q per year for the mid 1980s.[5]

B. Contribution by 2000 or Beyond

Projected fossil fuel use to generate electricity is expected to be about 46 Q in 1990 rising to about 73 Q by the year 2000.[6]

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[3] Energy Facts II, Committee on Science and Technology, U.S. House of Representatives. Series H, August 1975, p. 61.
[4] Op. cit.
[5] Industrial Cogeneration—What It Is, How It Works, Its Potential. Report to Congress, the Comptroller General, General Accounting Office EMD—8-7, Apr. 29, 1980.
[6] Energy Facts, op. cit.

Assuming no change in power generating technology [7] the ultimate fuel saving through cogeneration in utility power plants is about 11 Q in 1990, rising to about 18 Q by 2000.

The GAO study previously cited projects a cogeneration fuel saving in the range between 2 Q and 6 Q.

[7] There is a prospect that some new power plants will use fuel cells (see section on fuel cells) which are not compatible with topping and bottoming cycles but which have an efficiency of 45 percent to 50 percent. This is a slightly higher efficiency than expected of a conventiona plant equipped with a cogeneration cycle.

ENERGY CONSERVATION/EFFICIENCY

Energy conservation is most frequently discussed in terms of energy demand, largely because—at least in the near term—the potential for demand conservation far exceeds that which appears feasible on the supply side. However, there are definite possibilities for conservation on the supply side as well, and some of these would appear to merit discussion here because they are potentially significant.

Considered in terms of the supply of energy, as opposed to the demand-side uses of energy, conservation becomes a matter of increasing energy production and delivery efficiencies so that existing demands for energy can be met with minimum energy resource requirements. The production and delivery of energy, in turn, can be considered from the point of view of four primary areas:

(*a*) The production of primary fuels used for the generation of energy for consumption by various users;

(*b*) The transportation of this primary fuel to energy-generating facilities;

(*c*) The use of primary fuels in the generation of other forms of energy; and

(*d*) The transmission of energy from the generating facilities to the end-users.

As a practical matter, the bulk of the energy consumed in the United States is employed in the form of electricity or heat, including the conversion of the former into the latter. Hence, this chapter will discuss opportunities for energy conservation in the generation, transmission, and use of electricity.

I. Electric Power Generation*

This section of the report will examine possibilities for increasing the efficiency of electric power generation, and methods for maximizing utilization of existing generating capacity.

Most of the electrical power consumed in the United States is produced at present by coal-, oil-, and gas-fired generators with a smaller contribution from nuclear-fission, hydro, and geothermal powered generators.[1] In 1979, coal-fired generators supplied about 48 percent, oil-fired generators supplied about 14 percent, and gas-fired about 15 percent of the total electrical generation. Broken down by energy source, generation of electricity was as follows:

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* Prepared by Langdon T. Crane, specialist in science and technology.

[1] U.S. Department of Energy, Energy Information Administration. Annual Report to Congress, 1978, vol. 3, p. 265. DOE/EIA-0173/3.

TABLE 8.—*Generation of electricity by various energy sources*

[Billions of kilowatt hours, 1977]

Fossil fuels:	
Coal	1,075
Oil	304
Natural gas	330
Subtotal	1,709
Nuclear	255
Hydro and other	284
Total generation	2,248

Considering the technologies, both existing and under development, that might be used to produce electrical power in large amounts during the next 20 to 40 years, only two would seem to be assuredly available for large scale generators to replace or expand existing capacity. These are coal-fired boiler generators and nuclear fission reactor generators. Increasing costs will require that oil-fired generators only be employed on a limited basis. Many existing oil-fired units are now used primarily for cycling. This type of use of existing oil-fired plants will probably continue unless oil prices become very high, because these plants represent "sunk costs" and because oil-fired plants are easy to turn on and off. However, new oil-fired plants will probably not be built under existing policies and prices. Gas-fired generators (many of which are actually fueled by No. 2 oil) will continue to be used in the form of "fast start-up" turbines to meet peak power demand loads, but uses of actual gas-fueled base-load generators may well be fuel-supply limited. Hydro capacity cannot be expanded significantly without impairment to the environment and without imposing limitations on competing uses of our rivers and streams. Other sources of energy are either not ready for use or they present technical and/or economic problems that may limit their major usefulness to a few regions of the country. Thus, the discussion in this section will be limited to questions relating to the efficiency of electrical power generation by coal combustion and nuclear fission.

Coal-fired boiler generators now in use in the United States have thermal efficiencies as high as 40 percent. The key to these relatively high efficiencies is the high pressures and temperatures of the steam that can be generated by such boilers, plus the various methods available for reheating and recycling the steam through several stages of expansion to drive the turbine generator. This efficiency figure is quite high, approaching the best that one can hope to achieve under the limitations of existing materials from which boilers are made. Future processes, such as pressurized fluidized bed boilers, may be able to offer further improvements in efficiency—possibly as much as 5 percent[2]—because of better heat transfer within the boiler and because the flue gas itself may be employed to assist the steam in driving the generator turbine. However, this process is not in commercial use.

As far as coal-fired generators are concerned, primary reliance through the beginning of the next century, and perhaps for a decade beyond, will probably be upon boilers that are similar to the

[2] U.S. Office of Technology Assessment. The Direct Use of Coal. U.S. Government Printing Office, Washington, D.C., 1979, p. 103.

ones in use today. In current boilers, pulverized coal that has been ground to a very fine mesh is blown into the boiler chamber, where it burns rapidly as though it were a gas. Water flows in the walls of the combustion chamber and is heated primarily by thermal radiation from the exceedingly hot (about 3000 degrees F) flame. The steam is separated from the boiling water, and then is passed through tubing in the exhaust stack to be "superheated" to about 1000 degrees F. by the hot combustion gases as they escape from the combustion chamber. The steam is then expanded to turn the high pressure turbine section of the generator. Following this expansion the steam is returned to the boiler for reheating at a lower pressure. Once again it is expanded to turn a lower pressure turbine section of the generator, and then possibly is returned to the boiler for another cycle of reheating and expansion. When several cycles have been completed and no further energy can practically be extracted from the steam, it is condensed by very rapid cooling in a heat exchanger.

The steam cycle of the light water nuclear power generators now in use in the United States is simpler than that of coal-fired plants. In coal-fired plants, the high pressure superheated steam is separated from the main water boiler and subsequently is confined to small diameter tubing which can be made strong enough to withstand working pressures of as much as 3500 pounds per square inch (psi). Light water nuclear reactors, however, are constructed so that the reactor pressure vessel, which is very large in all of its dimensions, must withstand the full force of the pressure of the steam or superheated water being generated by the reactor. These pressure vessels are made of strong and thick material (steel), but operating pressures (and therefore temperatures) of the core pressure vessels are limited by the strength of the materials from which they can be made. Though other types of reactors offer the prospect of greater thermal efficiencies, the strength of the pressure vessels limits the efficiency of light water reactors to about 33 percent. Other reactors now under development, such as the high temperature gas cooled reactor, allow the use of much higher temperatures, and might be capable of efficiencies of about 40 percent. This is a very large difference in terms of the heat that must be discarded to the environment and the expense of the fuel consumed.

In practical terms, of course, the primary short term objective of energy conservation is the reduction in demand for petroleum energy supplies, particularly foreign petroleum supplies. Only 17 percent of U.S. generating capacity in 1977 was oil fired, and a good deal of that is being retrofitted to burn coal. Thus, it might seem that, insofar as the generation of electricity is concerned, the most important aspect of conservation issue may be disappearing. However, such a viewpoint only addresses one aspect of the energy supply conservation problem. The real objective of supply conservation is to minimize the cost of energy in our energy-intensive society. It is increasingly important that the cost of energy, in all of its forms, be kept as low as possible to minimize inflation and maximize productivity, thereby assuring that American products can be competitive in foreign markets and that American wages and employment can remain high, so that the American standard of living can be maintained. As petroleum resources become more expensive, electrical power can be an important substitute for certain uses of petroleum-based fuels provided that electricity does not become too expensive (and that oil is not used for power generation). In this situation, conservation in terms of maximized thermal efficiencies is secondary: the goal must be to maximize the economic efficiency (i.e., reduce the cost) of all aspects of the generation and distribution of electrical energy. The remainder of this discussion will address the question of energy conservation in the electric utilities from that standpoint.

Turning first to the generation of electrical power, there would seem to be (for the reasons mentioned above) only two assured alternatives for the generation of electricity on a large scale: coal combustion and nuclear fission. In certain areas of the country, it is alleged that nuclear fission plants may generate power at lower cost than coal plants even though they are more expensive to build. One determining factor is the cost of mining and transporting the coal, which modern plants use in very large quantities in spite of their high thermal efficiencies: a 1000 megawatt plant with a load factor of 0.75 will consume about 2.5 million tons of coal in a year if operated continuously. That volume of coal requires the arrival each weekday of the year of enough coal to fill a train consisting of 100 coal cars having a capacity of 100 tons each. Clearly, fuel and fuel handling are major expenses when power is generated by coal combustion. A nuclear plant of the same size and load factor would annually require only about 140 tons of new fuel, a material whose energy content per unit of cost is significantly greater than that of coal.

Why, then, not convert electric power generation to nuclear? The answer lies mainly with the issue of public safety, and environmental impacts, plus a number of other ancillary issues currently being debated. Nuclear power has raised a number of questions, such as the risks of increased cancer from normal operation of the plants, the possibility of accidents that might kill large numbers of people, thermal and other pollution to bodies of water used for cooling, and the possibility of nuclear weapon proliferation. The alternative risks of coal combustion are not so well known, but several recent studies have concluded that they are probably greater than those of nuclear power.[3] For example, some current estimates indicate that the fueling and normal operation of a nuclear power plant of 1000 Mw capacity might result in the death of between 0.6 and 1.7 people on the average each year. Estimates of the deaths that might be expected to occur, on an average annual basis from nuclear accidents range from 0.02 to 2.4 per plant, making a total average annual death rate per plant of 0.6 to 4.1 per nuclear plant in operation. Such estimates indicate that a new coal plant of that size might cause 4.2 to 120 deaths among the general public each year from coal transportation and combustion emissions, plus an additional 0.3 to 5 occupational deaths among those who mine, process, and transport the coal. These estimates, however, are not

[3] (1) National Academy of Sciences. Committee on Nuclear and Alternative Energy Systems. Energy in Translation: 1985–2010. Washington, D.C., 1980. (2) Keeny, Spurgeon M. et. al. Nuclear Power Issues and Choices. Ballinger Publishing Co., Cambridge, Mass., 1977. (3) Schurr, Sam H. et. al. Energy in America's Future: The Choices Before Us. Resources for the Future. Johns Hopkins University Press, Baltimore, Md., 1979.

subject to solid verification and are not necessarily accepted by all experts. The lack of general awareness about the relative magnitudes of estimates of risk of coal and nuclear power may have contributed to a trend away from the former rate of growth of nuclear fission power generators. The Three Mile Island accident could possibly enhance that trend. However, should the suspected risks of coal combustion become substantiated, there may be a reverse trend toward nuclear power once again. Among other factors which affect the use of nuclear power are (1) the many unresolved regulatory and safety issues, (2) the question of the relative costs of construction of coal and nuclear plants and the relative costs of the respective fuels, and (3) possible construction and licensing delays caused by intervenors.

A possible shift toward electrical generation by nuclear fission may be affected by factors other than costs, health, and environmental considerations. A recent report of the General Accounting Office points out that if the growth of nuclear power is halted, then either the growth of demand for electric power may have to be severely limited or there may have to be a very vigorous effort to expand coal production to supply demands by the end of the 1980s decade. The crucial factor is the growth rate of demand for electrical power.[4] If demand fails to increase at the predicted rate, these problems might not materialize or might not be as serious as GAO predicted. The problem, of course, is complicated by the increasing price and possible scarcity or irregularity in oil and natural gas supplies.

II. Electric Power Transmission and Distribution *

It is generally believed that the electrical losses of all kinds in the U.S. electrical transmission and distribution system are about 10 percent of all electricity entering the system from domestic electrical generating centers, and imported from outside U.S. borders.[5] According to the Energy Information Administration (Op. Cit., p. 9.) about 30 percent of U.S. energy consumption goes into the generation of electricity. This section addresses the question of how much of this loss of primary energy could be saved by increasing the efficiency with which electricity is transported and distributed.

Estimates[6] obtained from the Department of Energy's Electric Energy Systems Division, under the Assistant Secretary for Resource Applications, indicate that there are several principal areas where new technology development or systems analysis could result in significant electrical transmission and distribution loss savings, as discussed below.

A. *Low-Loss Transformer Materials*

The Electrical Energy Systems Division estimates that very significant electricity savings could result from research and develop-

* Prepared by David Hack, Analyst in Energy Technology.

[4] See: U.S. Congress. House. Committee on Interstate and Foreign Commerce. Will the Lights Go On Again in 1990? Washington, U.S. Government Printing Office, August 1980, 15 p.

[5] For example, see U.S. Energy Information Administration. Annual Report to Congress. Vol. 2, 1979, p. 115.

[6] Telephone conversation, December 1979.

ment of lower-loss magnetic materials (amorphous metals) for use in transformers. It is thought that as much as one-half of the 10 percent loss in the transmission and distribution of electrical energy may be losses in transformers alone. (Amorphous metals may have energy conservation applications in electric motors and generators also, but these are outside the transmission and distribution system.) Little benefit from such research is likely to occur before 1990, but it is estimated that an expenditure by the Government of as little as $2 million over the next few years could ultimately result in a saving of about 40 percent of the energy now lost in these transformers, or about 2 percent of annual electrical generation (fuel savings of about 0.5 quads per year).

B. Cryogenics and Superconductivity

Cryogenics and superconductivity are technologies which reduce the electrical resistance losses in transmission by using conductors maintained by refrigeration at temperatures near absolute zero (−273 degrees C). Some projections anticipate such low-loss transmission lines to be commercially applicable sometime in the 1990s. Research on such transmission lines has reached the point where a 100 meter section of cryogenic transmission line is scheduled to go into operational testing at Brookhaven National Laboratory sometime in 1980. No estimate of ultimate energy saving is available.

C. Assessment of Electrical Losses

The Electric Energy Systems Division believes that about $1,000,000 could be spent cost-effectively on research on models for assessing electrical losses. It seems that to a substantial extent it simply is not known exactly where electrical losses are occurring in most transmission and distribution systems. Estimates of where these losses occur are made now by rule of thumb. The development of an analytic system for assessing the locations and magnitudes of these losses, in a generic sense, could help individual utility companies and regional electric systems to identify areas for improved efficiency. However, no estimate of the ultimate energy saving is available.

D. Three-Dimensional Field Analysis

It is believed that there could be a substantial pay-off from research and development of three-dimensional electrical field analysis, to take advantage of the large computers now available. Present analyses rely on the approximations available in models and computer programs which simulate only two dimensions, and this limits the ability to design transformers and generators for maximum efficiency. The Electric Energy Systems Division estimates that about $2 million could profitably be spent over a 3 to 4 year period on development of three-dimensional field analysis computation techniques. In addition, it might take as much as $5,000,000 in Government commercialization funds to get the medium-power transformer industry into the effort to apply this new design technique and tool up for manufacture of such equipment. No estimate of ultimate energy savings is available.

E. Interpolated Graphite Conductors

Going beyond the four areas above where efficiency improvements are more substantial and certain, the Electrical Energy Systems Division also suggests that $3–3.5 million could be spent cost-effectively over about 4–5 years on exploratory work on "interpolated graphite conductors," a type of conductor which is made by combining the electrical conduction properties of graphite and copper in one material.

F. High-Voltage Alternating Current Transmission

On high-voltage alternating current lines, the focus is currently on voltages in the 1200 Kv range. Electric Energy Systems Division is doing no work on what it regards as the state-of-the-art 750 volt transmission systems. Instead, it is doing longer range research in material and design properties required for circuit breakers, lightening arrestors, insulators, and substation design for 1200 Kv range transmission systems. Substation design includes considerations of both size and land use. Another problem may be the environmental acceptability of the electrical fields surrounding substations and transmission lines. Again, we have no estimate of the ultimate energy savings available.

G. Direct-Current Electricity Transmission

Research is also going on with so-called ±600 Kv direct-current transmission, in which two direct-current conductors are used with a 1200 Kv potential difference between the lines, each conductor, however, differing from ground potential by only 600 Kv. It is believed that such lines lose about 3 percent of their energy in the conversion equipment at both ends of the line, and current research is directed to increasing the efficiencies of the thyristors or crystal converters which convert from AC to DC and back again. There appears to be a possibility that these converter installations may also present considerations of physical size and land use. An expected 15 percent increase in the efficiency of these thyristors would result in a saving of 0.45 percent of the energy transmitted. No estimate of the total ultimate energy savings available from high voltage DC transmissions, with or without thyristors of increased efficiency, is presently available.

III. Interties and Grids for Electric Power *

Historically, electric utilities have tended to operate on a principle of self-sufficiency: each utility provided all of the power to be used in its own region. The recent trend, however, has been toward interconnections of individual utilities to improve reliablity of service by having emergency sources of energy available from other utilities, and to achieve economies of operation and investment by integrating several utility systems and operating them as a unit.

Thus far, the majority of interconnections in the United States have been for the purpose of improving reliability. Nine regional councils have been established, constituting the National Electric

* Prepared by Langdon T. Crane, specialist in science and technology.

Reliability Council, to assist in coordinating system planning to improve reliability.[7] Three major transmission networks have been established to improve reliability, but they do not employ central dispatching of energy generated by utility pools and the individual utilities which they interconnect. The utility pools in the three large neworks, however, do tend to coordinate the planning of new capacity, maintain load frequency control, and coordinate maintenance scheduling. These pools permit, in principle, economies of scale and operation, for they permit very large and efficient generators to be built and generating reserves to be pooled.

In contrast to the networks, there are other interconnected utilities which do employ central dispatching. These are mostly located in the East. Some of these interconnected utilities using central dispatching are held by a single holding company, while others are voluntary associations of independent utilities. Central dispatching offers a clearer opportunity for economic optimization through economies of scale in generating and transmission equipment, reduced excess capacity requirements to allow for maintenance and possible emergencies, reduced operating costs because fewer generators need to be turning in "standby" condition to meet a possible generator failure in the system, and greater overall reliability of the system thus coordinated. About 38 percent of U.S. generating capacity is interconnected with central dispatching.

It seems possible that considerable fuel and other economic savings might be achieved if all the utilities in the United States were to be operated as one large national grid. However, a recent study[8] indicated that such operation would result in a savings of only about 3 percent in the average residential power bill at maximum, though it must be noted that there are very limited data available regarding the savings that have resulted from interconnections and central dispatching. Thus, there seems to be no definitive answer to the question of how great the savings might be: some would insist that such operation might offer significant advantages in terms of economic savings and system reliability, while others feel that most of the advantages have already been captured under existing intertie arrangements. The significant added advantage of large scale interties, of course, is the ability to "wheel" power from one utility or region to another, so that when the load is highest in one region, or time zone, power can be brought in from another region or time zone. Whether such advantages have, in fact, been captured or not is a question that needs to be answered through careful analysis.

Though interconnections between utilities and pools of utilities are commonplace, it cannot be assumed that a national grid can operate successfully using the methods of operation and hardware that are available today. As two well-publicized blackouts in New York have shown, an interconnected system offers new possibilities for failure that tend to grow with the magnitude of the interconnection complexity. In one case, a failure in the transmission line in Canada resulted ultimately in a failure of the entire New York City power system. Transmission lines and distribution systems

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[7] See: Probozich, Russel J., and Alvin Kaufman. Electric Utility Interconnection and Wheeling of Power. Report. Congressional Research Service. Feb. 14, 1978.

[8] U.S. Congress. Senate. Committee on Interior and Insular Affairs. National Power Grid System Study—Overview of Economic, Regulatory, and Engineering Aspects. Washington, D.C., U.S. Government Printing Office, 1976.

are clearly vulnerable elements, more vulnerable than generators by quite a margin. The rapid analysis of transmission line failure would seem to require a greater degree of computer assistance and control to avoid blackouts resulting from remote failures in such a large system, for human reactions may well not be fast enough. Switching systems must be improved, for they occasionally fail when needed most. The frequency and phase of generators would have to be regulated more carefully, and loads carefully controlled so as not to produce unnecessary instabilities in the system. These and other elements in the electric power utility systems would seem to require extensive development and improvement, and might require considerable revision in the methods of human control that are exercised in power utilities and systems, before a large national intertie or grid can be fashioned to operate with the advantages in reliability that might be claimed. However, since this development and improvement would be funded primarily by private industry, it would not seem to require large scale investments by the Federal Government in the 1980 to 2000 time period, nor do such investments seem to be in planning at present.

IV. Energy Conservation in the Transportation of Coal *

A. Introduction

This section examines the energy cost of transporting coal by highway, water, rail, unit trains, and slurry pipelines. The total dollar costs of unit trains and of pipelines are then compared in order to suggest the likelihood that selection of one of these modes might result in energy consumption savings relative to selection of the other mode.

B. Coal Transportation Technologies

Transportation by highway involves use of trucks of various sizes and descriptions, usually on highways constructed and maintained at public expense—but sometimes on private roads which may accommodate trucks too large for public highways.

Transportation by water primarily involves barges lashed together by steel and cable and powered by tugboats. These "tows" ply a system of rivers, channels and locks maintained by the Army Corps of Engineers. On the Great Lakes, however, coal is also transported in self-powered cargo ships.

Transportation by rail means the conventional hauling of coal by private railroad companies as common carriers—who receive and deliver coal in lots as small as one carload—assembling and disassembling shipments into and from larger trains as required. Unit trains (for coal hauling purposes) are those which carry coal as a sole cargo in trains up to about 100 cars, from a single loading point to a single unloading point; this may be arranged by long term contact, sometimes with cars and locomotives owned by the coal customer rather than the railroad company(ies) over whose right of way the unit trains move. Some unit trains also move on railroads built and owned by mining or electric utility company interests.

* Prepared by David Hack, analyst in energy technology.

Slurry pipelines are a means to transport coal long distances (up to 1,000 miles or more) by mixing crushed coal with water and pumping the mixture through a pipe buried underground. Of all the coal used in the United States, a very small quantity is currently transported by pipeline. There is at present only one slurry pipeline in operation; it transports about 5 million tons of coal per year (less than 1 percent of U.S. coal production) 273 miles from northeastern Arizona to southern Nevada.

C. Energy Use of Different Coal Transportation Technologies

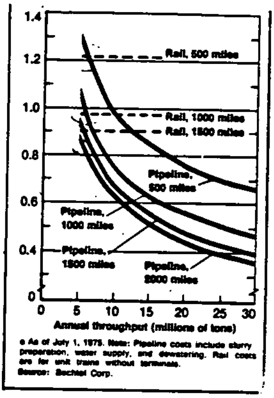
Table 9 shows that highway transportation of coal requires by far the greatest expenditure of energy: more than 12 percent of the energy in the coal, per 1,000 mile haul. The most energy efficient means of coal transportation, according to Table 9, is the unit train, which can transport coal 1,000 miles using energy equivalent to only 2.0 percent of the energy in the coal; all other means of coal transport require more than half-again as much energy (3.2 to 3.5 percent per 1,000 miles—for pipeline, barge, or conventional rail).

D. Dollar Cost of Transporting Coal by Slurry Pipeline or Unit Trains

The total dollar cost of transporting coal by pipeline and by unit train is compared in Figure 2.

FIGURE 2. Pipelines Can Take Advantage of Scale (transportation costs in cents per ton-mile).

Cents Per Ton-Mile



Excerpted from "Economics A Plus for Coal Slurry Pipelines," Chemical and Engineering News, vol. 55, June 27, 1977: 20-21.

TABLE 9. ENERGY CONSUMPTION IN TRANSPORTING COAL BY VARIOUS MODES (Btu's per ton-mile)

Mode	Estimate or Average	Range	Percent Loss per 1,000 miles
Highway 1/	2,500 +	2,518-2,800	more than 12
Rail 1/	663 (est.) 3/	536-791	3.5 (est.)
Barge 1/	610 (est.) 3/	540-680	3.2 (est.)
Pipeline 2/	610 (avg.)	410-1,150	3.2
Unit train 2/	390 (avg.)	340-580	2.0

1/ Study prepared by Missouri Railroad Traffic Research Division, cited in Railway Age, "The Energy Sweepstakes: Railroads are Easy Winners," re-cited in: U.S. Congress. Senate Committee on Energy and Natural Resources; House Committee on Commerce, Science, and Transportation. National Energy Transportation, Volume I--Current Systems and Movements [report prepared by the Congressional Research Service]. 95th Congress, 1st session. Washington, U.S. Govt. Print. Off. May 1977. p. 85.

2/ U.S. Congress. Office of Technology Assessment. A Technology Assessment of Coal Slurry Pipelines. Washington, U.S. Govt. Print. Off. March 1978. pp. 120-121.

3/ The estimates (est.) presented here were made by taking the mid-point of the corresponding "Range."

According to Figure 2, there is no financial advantage for newly constructed slurry pipelines unless the pipeline carries an annual throughput of at least 5 million tons. For larger throughputs, the financial advantage of pipelines increases to as much as 0.5 cents/ton-mile at throughputs approaching 30 million tons per year.

E. Energy and Dollar Tradeoffs of Transporting Coal by Slurry Pipeline or Unit Train

The data of Table 9 and Figure 2 together allow us to calculate two quantities of interest. One is the dollar saving from carrying (for example) 30 million tons of coal per year a distance of 1,000 miles by pipeline instead of by unit train. The financial saving is $150 million in 1975 dollars.

The second quantity of interest is the energy cost of thus carrying the coal. Referring to Table 9, this cost is the difference between 3.2 and 2.0 percent (that is just 1.2 percent) of the energy contained in the coal transported, or 0.008 quad per year.

From these figures one may calculate that the saving of energy achieved by the unit train comes at a cost of about $420 per ton of coal, and that the price of oil for diesel fuel would have to be over $100 per barrel to make this energy saving pay.

From the above it appears that pipelines use more energy, but save money, while unit trains cost more money but save energy. However, with present railway locomotives there would be a net increase in petroleum fuel consumption by unit trains compared to pipelines since rail power today is almost entirely by diesel electric locomotive, while much of the electricity which pipeline pumps would use would come from coal. The amount of diesel fuel required to carry 30 million tons of coal 1,000 miles appears to be about 0.013 quads, or 2.3 million barrels.

It appears that a way to get both the energy efficiency advantages of unit trains, and the petroleum saving advantages of slurry pipelines, would be to power unit trains with some derivative of coal. Several possibilities that do not appear to have been considered in studies of coal transportation include: (1) use internal combustion electric locomotives similar to those used now, but which would run on a liquid derivative of coal instead of on diesel fuel, (2) develop a new generation of steam powered locomotives running on solvent refined solid fuel from coal, or (3) use electric locomotives and overhead electric lines fed by stationary coal-fired electric power plants. However, some of these "derivative" technologies might reduce the efficiency difference by interposing another energy transformation between the fuel resource and the transportation machinery.

But are such measures warranted by the size of even the maximum energy saving available? A saving of 1.2 percent of the energy in a 1,000 mile haul means that if all the coal produced in the United States (1979) were hauled 1,000 miles by unit train instead of by slurry pipeline, the energy saved would be only 0.27 percent of all U.S. energy consumption.

F. Environmental and Political Obstacles to Slurry Pipelines and Unit Trains

A study by the Office of Technology Assessment [9] concluded that water requirements and possibly some transient effects of construction constitute the principal source of adverse environmental and social impacts associated with coal slurry pipelines. For railroads the major negative impact is social—the disruptive effect of increased unit train traffic upon the lives of individuals living or working near the tracks. Some of the adverse impacts that result from increased unit train activity can be mitigated. Other environmental and social impacts associated with either coal slurry pipelines or unit trains are not particularly serious or are roughly equivalent for the two modes.

The political issue of eminent domain for acquisition of right of way by coal slurry pipelines arises in large part because railroads and other landowners, under whose land pipelines would have to cross, have declined to grant the necessary rights of way. At present no Federal legislation grants eminent domain authority for coal slurry pipelines. Comparison of coal slurry pipelines with oil pipelines suggests that State eminent domain authority may not be as effective in meeting the needs of coal pipelines as it has been for oil pipelines—the OTA concluded.[10]

G. Conclusion

Slurry pipelines, while quieter and less obtrusive through most of their right of way than unit trains, and while less costly to build and operate over their useful lifetimes, do not save energy relative to unit trains—though they may save money and oil. Unit trains, while perhaps one-third more energy efficient than slurry pipelines, do not save oil with present technology. They do save a little fuel, primarily coal, at a cost far in excess of the current market price of coal. Based on the limited data examined here, neither slurry pipelines nor unit trains appears to have any significant potential for reducing U.S. oil dependence by 1990. Beyond 1990, when slurry pipelines now planned or being considered may have begun operation, there is a small potential for displacement of diesel fuel which otherwise might be consumed in increased operation of unit trains. One slurry pipeline carrying 30 million tons of coal annually a distance of 1,000 miles might displace about 2.3 million barrels of oil (0.013 quads) annually.

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[9] U.S. Congress. Office of Technology Assessment. A Technology Assessment for Coal Slurry Pipelines. Washington, U.S. Government Printing Office, March 1978, 155 p.

[10] Office of Technology Assessment. Op. cit, pp. 20–23.

OTHER TECHNOLOGIES

FUEL CELLS*

I. Survey of the Current Situation

The lure of the fuel cell is its ability to convert fuel into a continuous flow of electricity at high efficiencies. The maximum theoretical efficiency of a fuel cell is 83 percent and fuel cells with operating efficiencies of over 50 percent have been fabricated.[1] The average efficiency of a conventional power plant, by contrast, is 35 percent.

A. Description of the Technology

Although there are several chemical reactions which can be used, the fuel cells in use today depend upon the oxidation of hydrogen to produce electricity. The hydrogen is usually stripped (reformed) from a hydrocarbon fuel or from water. Oxygen is supplied by the introduction of air into the system. If pure oxygen and hydrogen were required, even a low cost fuel cell would not be able to compete economically with conventional systems. Early attempts to use common fuels, e.g., gasoline or methane, quickly encountered problems of low current yield and rapid contamination of the closed and pressurized fuel cell interior. Through many arduous steps it came to be realized that the electricity obtained when using conventional fuels was not being provided by the oxidation of the fuel itself but by the hydrogen being stripped from the fuel and from water, if water was present. The carbon in the fuel was joining oxygen to form carbon monoxide or carbon dioxide. The fuel was being "reformed" to produce hydrogen and the low output was due to lack of provisions for efficient reforming.

This finding led to fuel cells designed for internal fuel reforming at the anode (positive electrode) when the fuel was exposed to steam. The oxygen in the water molecule would capture the carbon in the fuel and release hydrogen for oxidation in the fuel cell. Although this worked, the electrolyte was still contaminated. External fuel processing, a separate reforming process, proved superior. More energy is required but the fuel cell is protected, not only from hydrocarbons, but also from sulphur present in some fuels. Coal can also be used in this fashion. When reacted with steam, carbon oxides are formed and hydrogen is stripped from the water to power the fuel cell.

Operating temperature provides a convenient means of distinguishing categories of fuel cells. They may be: (*a*) Low temperature, below 200 degrees C; (*b*) medium temperature, up to 500 degrees C;

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* Prepared by George N. Chatham, specialist in aeronautics and space.

[1] McCormick, J. Byron. Fuel Cells for Transportation. Industrial Research and Development, April 1980, p. 88.

or (*c*) high temperature, up to 1,000 degrees C. There are also other ways to classify cells. For example, their electrolytes may be alkaline, acid, liquid, solid, or molten. The way they accept and oxidize fuels also distinguishes them. They may use direct oxidation (hydrogen and oxygen only), internal fuel reforming, or external fuel reforming.

B. Known Resources Reserves

Any hydrocarbon or carbon fuel can be reformed to supply hydrogen which can be oxidized in a fuel cell with atmospheric oxygen. Known resources and reserves are therefore not a critical issue to the use of the fuel cell and are addressed in the chapters of this report which cover fossil fuels.

C. Current Contribution to U.S. Energy Supplies

There is no contribution to energy supplies from fuel cells at the present time.

D. State-of-the-Art

Several types of fuel cells using costly catalytic systems have been demonstrated successfully in military and space applications. For general application, where both cost and availability of catalyst materials are issues, however, only the phosphoric acid electrolyte cell has been proven by more than 15 years of fabrication and field test experience.

An advanced type of cell, using a molten carbonate electrolyte, is in the development process. This high temperature system is designed to apply rejected heat from the fuel cell chemical oxidation to a coal gasifier, thus reforming coal to supply hydrogen. The coal gasifier technology is well understood, but the molten carbonate electrolyte system requires additional research.

E. Current Research and Development

1. THE PHOSPHORIC ACID CELL

The 4.8 Mw Consolidated Edison utility installation.—The first program to demonstrate the phosphoric acid fuel cell is scheduled to begin operation during 1982. This project will determine the acceptability of the phosphoric acid fuel cell as an on site source of power, as well as highlight the technical weaknesses of the system for the purpose of product improvement.

The 40 Kw on site/integrated energy system.—The second program to demonstrate the phosphoric acid fuel cell will undertake the placement of several kilowatt-sized units (averaging about 40 Kw each) in large apartment or office complexes. They will test a number of total energy use ideas in which fuel cell rejected heat is applied to meet the thermal requirements of the building. The DOE identifies this program as an "on site/integrated energy system (OS/IES). This program will be a product improvement research phase, aimed at cost reduction, and will be funded by the builder, United Technologies, DOE and the Electric Power Research Institute (EPRI). No problems are anticipated for the completion of this phase. However, commercialization, discussed below, may require a subsidy during the period prior to volume production.

2. THE MOLTEN CARBONATE CELL

The concept of using any grade of coal in an efficient, clean power generating plant becomes increasingly attractive as the expense and scarcity of petrochemicals further penalizes conventional power generation. The molten carbonate cell, thermally integrated with a coal gasifier system, is an advanced concept at this time.

Although the coal gasifier system and the thermal integration of the fuel cell and gasifier is well understood, the molten carbonate cell is still in the research phase. Funds from EPRI and United Technologies have paid for the initial research. Continued expenses are being shared with DOE. In 1979, DOE selected two firms to work independently on the technology of the molten carbonate fuel cell power plant. Contracts valued at about $15 million each were awarded to United Technologies and General Electric. They are to be completed in 33 months.

Anticipated Federal funding for fuel cells for fiscal year 81 amounts to about $2 million.

II. Prospects or Requirements for Future Development

Further development of the fuel cell as a power generator requires field experience, such as will be acquired from the Consolidated Edison plant, product improvement stemming from this experience, and the solution to economic barriers discussed in the third section of this chapter. Other matters relevant to research and development are covered by sections one and three of this chapter.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

The phosphoric acid electrolyte fuel cells now being demonstrated are first generation production cells which have emerged from extensive field testing programs. Although product improvement, especially cost reduction, is a normal expectation, no technical obstacles are anticipated in function or lifetime. The fuel cell art, however, is largely unexplored. New types of fuel cells may be expected to emerge in the future as applications experience is combined with research results.

B. Economic

Commercialization of the fuel cell faces only one obstacle of significance, and that is a cost problem related to production quantity. The 4.8 Mw demonstrator plant to be operated by Consolidated Edison was engineered to be sold to a utility for $350/kw in production. The quantity required to reduce the price to the $350/kw goal is estimated by the United Technologies and EPRI to be between 500 and 1500 Mw capacity in fuel cells, according to their representatives. Averaging those limits, this is about 200 times the output of the 4.8 demonstrator. According to EPRI (telephone conversation), the first plant, the demonstrator, will cost about $1,500 kw with the price declining about 15 percent with each doubling of capacity produced.

Considering the total life output of the cell, its value to a utility (what they will pay) lies between $330 and $600/kw, the difference being a function of how severely siting options are restricted. In round numbers, and considering the steady decline in cost as production continues, a premium of about $500 million is the size of the economic barrier to reach the competitive production cost of $350/kw on the type of fuel cell developed for the Consolidated Edison plant (telephone conversation).

The $500 million premium, considered in the context of other Federal energy development expenditures, seems relatively modest. The fiscal year 1981 request for solar energy, for example, is over $700 million.

C. *Environmental*

The fuel cell itself is silent and its effluents, water and a small amount of heat, are benign to the environment. The fuel reforming process, in which hydrogen is obtained from a hydrocarbon fuel or from water when steam is reacted with coal, will require designs and pollution safeguards compatible with the site chosen for a fuel cell power plant.

IV. Potential Contribution to Future U.S. Energy Supplies

A. *Fuel Conservation*

1. POTENTIAL

First generation cells, like the phosphoric acid cells to be used in the 4.8 Mw demonstration, will have an efficiency of about 40 percent. However, production cells beyond those to be used in the demonstration plant would be second generation, with efficiences of about 45 percent according to EPRI (telephone conversation). This is about a 12 percent improvement over the average conventional power plant.

The fuel cell power plant provides another means of conservation, almost as great as the gain in fuel efficiency. About 10 percent of the power generated today is lost due to line resistance and induction. Conventional power plants tend to be remote from consumers due to their size and environmental effects. They also tend to be very large since their design characteristics give an economic advantage to scale.

In contrast, fuel cell plants may be small. They are silent and their noxious effluents are an order of magnitude below Federal standards. Siting problems are therefore minimal and they may be dispersed into the areas they serve, thus greatly reducing line losses.

Molten carbonate cells, still in the research phase, are expected to have similar characteristics and efficiency but may be fueled with coal of any grade or with petrochemicals. Successfully developed, these cells hold the prospect of overcoming the main problem in converting petrochemical plants to coal, that of controlling the harmful effluents.

2. ACTUAL

Although demonstrations will occur throughout the next decade, 10 years is not sufficient, even with a solution to the marketing barrier, for the fuel cell to have a significant impact on fuel consumption. Up to the year 2000, EPRI and United Technologies project that fuel cell power plant construction will account for 8 to 10 percent of the national capacity.

It has been stated that although the 10 to 20 percent higher fuel efficiency of the fuel cell is a major attraction, the market inroads made up to the year 2000 will be related more to the environmental benignity of the plants.[2] In California, for example, a basic power plant may be estimated to cost $1,000/kw but an additional $2,000/kw must be added to comply with environmental regulations.[3] Half of the added sum is needed for effluent control from the plant. The other $1,000/kw is used to buy nearby manufacturing plants in order to close them down. The closed plants provide the needed "offset" to keep airborne contamination within California's established limits.

As to fuel savings, if a 10 percent market inroad by the year 2000 is correct, and the fuel cell plants are 20 percent more efficient than conventional plants, direct overall fuel savings will be about 2 percent.

There are indirect savings, too. Fuel cell power plants may be made small without an efficiency penalty. They can therefore be located in the area they are to serve. This characteristic makes the use of rejected heat attractive for district heating or cogeneration. It also reduces the transmission losses. Net impact of these savings could be, according to EPRI, as much as an additional 20 percent of the direct fuel savings or a net gain of 25 percent total fuel consumption for power generation. This would mean a total overall of 2.5 percent reduction by the year 2000.

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[2] Mr. Ed Gillis, fuel cell project manager, EPRI, personal conversation.
[3] Ibid.

GEOTHERMAL ENERGY *

I. Survey of the Current Situation

A. Description of the Technology

Geothermal energy is generally defined as that portion of the Earth's heat contained within the crust relatively near the Earth's surface. In most areas this heat is so diffuse that it cannot be economically recovered. In some areas where the underlying geologic structure has led to favorably high heat flow, the geothermal energy is concentrated and can be recovered as steam or hot water. These products can be used directly for space heating, industrial and agricultural purposes, or indirectly through generation of electricity. However, even the best of these geothermal deposits, such as The Geysers dry steam field in California, are relatively low-grade energy sources when used to produce electricity. The geothermal steam supplying the electric powerplants at The Geysers is at a temperature around 355 degrees F and 100 pounds per square inch pressure. This contrasts to steam produced by fossil fuel plants which is around 1,000 degrees F and 3,700 pounds per square inch pressure. The lower temperatures and pressures of geothermal steam plants result in lower efficiency in converting the heat energy into electrical energy. The thermal efficiency of producing electricity from hot water deposits, such as those in the Imperial Valley in southern California, is also low and such deposits generally require additional technological complexity to utilize for that purpose.

Present technology can be divided into three categories: exploration, drilling and utilization. The objectives of exploration are to locate areas underlain by hot rock; to estimate the volume, temperature, and permeability at depth; and to predict the characteristics of the geothermal fluid when brought to the surface. Photographic interpretations, aeromagnetic and airborne infrared surveys may be useful for mapping surface thermal manifestations. Geochemical exploration involving sampling of waters and gases from springs, steam vents, drill holes and streams is also used. Ratios and nature of chemical constituents and isotopic composition yield information concerning minimum reservoir temperatures, homogeneity of fluid supply, chemical content of water at depth, and source of recharge water. Geophysical techniques that are most useful include geothermal gradient surveys, heat-flow determinations, electrical-conductivity surveys, and passive seismic methods incuding microearthquake measurements.

Geothermal wells are drilled with the standard rotary rigs that are used in the oil and gas industries. Drilling fluid is usually a low-solids gel and fresh water system. As temperatures increase with depth, the drilling mud dehydrates and becomes viscous.

* Prepared by James E. Mielke, specialist in marine and earth sciences.

Thus, where possible, The Geysers wells are drilled with air to increase the drilling rate and to reduce loss of circulation problems. Imperial Valley wells are completed with slotted liners through the hot brine intervals. The Geysers area wells are completed in open hole with a liner set just above the steam-zone prior to drilling the well to the bottom.

For commercial utilization, a geothermal deposit is engineered to provide a certain rate of thermal energy production for a specified number of years. Well stimulation techniques may be used to increase the flow of hydrothermal fluids or to create cracks in impermeable hot rock formations. These techniques include the use of hydraulic fracturing, chemical solvents, and explosives. Hydraulic fracturing consists of pumping a fluid down the well with sufficiently high pressure to produce cracks at the bottom of the well. The cracks are extended as pumping continues. After a period of production, a hydrothermal system may decrease in flow because of solids deposited in the formation decreasing the permeability. This tendency can be countered by injecting chemical solvents to dissolve the solids.

In wet steam (hot water) reservoirs, heat is extracted for power generation by either partly flashing (rapid boiling induced by reduced pressure) the liquid into usable steam or by a binary system in which the heat energy is transferred to a secondary working fluid having a lower boiling point. Another use for the geothermal resource is space heating by conducting the hot water fraction directly to buildings.

B. Known Resources and Reserves

Geothermal resources are usually divided into four classes: hydrothermal convection systems, including vapor-dominated and hot-water systems; geopressured deposits; hot tight rock deposits; and magma systems. An assessment of U.S. geothermal resources is summarized in table 10.

1. HYDROTHERMAL CONVECTION SYSTEMS

Hydrothermal resources consist of water and steam trapped in fractured rocks or sediments by confining surface layers. A specific hydrothermal system is classified as "vapor" or "liquid" dominated, according to the principal state of the subsurface fluid. Hydrothermal resources are currently being utilized for electric production and direct thermal applications.

Vapor dominated geothermal systems, such as The Geysers in California or Larderello in Italy, are relatively rare. Production of steam from such reservoirs results in a decline in pressure, causing the water in the rock pores to flash to steam using the heat stored in the reservoir rocks. All large known vapor-dominated systems are characterized by prominent natural vent areas. Although few vapor-dominated geothermal deposits are known, this type of deposit has been the most successfully utilized geothermal deposit for the production of electricity.

TABLE 10.—GEOTHERMAL ENERGY OF THE UNITED STATES

	Accessible resource base to 10 km (10^{18} J)	Accessible resource base to 7 km (10^{18} J)	Accessible fluid resource base to 6.86 km (10^{18} J)			Accessible resource base to 3 km (10^{18} J)			Resource (10^{18} J)	Electricity (MWe for 30 yr)	Beneficial heat (10^{18} J)
			Sandstone	Shale	Total	>150° C	90–150° C	Total			
Conduction dominated:											
Land area	33,000,000	17,000,000						3,300,000			
Offshore gulf coast	370,000	180,000						36,000			
Total	33,000,000	17,2000,000						3,300,000			
Igneous related:											
Evaluated	101,000										
Unevaluated	>900,000										
Total	>1,000,000										
Reservoirs of hydrothermal convection systems (>90° C):											
Identified						950	700	1,650	400	23,000	42
Undiscovered						2,800–4,900	3,100–5,200	8,000	2,000	72,000–127,000	184–310
Total						3,800–5,800	3,800–5,900	9,600	2,400	95,000–150,000	230–350
Northern Gulf of Mexico basin (onshore and offshore):											
Thermal energy	850,000	410,000	11,000	96,000	107,000				270–2,800		
Methane energy			6,000	57,000	63,000				158–1,600		
Total			17,000	153,000	170,000				430–4,400		
Other geopressured basin					46,000						

Note.—Energies are in joules (J); 10^{18} J is approximately 10^{15} British thermal units (Btu) which, in turn, equals 1 quad (a quadrillion Btu).
Source: Muffler, L. J. P. (editor), "Assessment of Geothermal Resources of the United States—1978," Circular 790, U.S. Geological Survey, Reston, Va., 1979, 163 p.

Most hydrothermal convection systems deliver a mixture of hot water and 10 to 30 percent steam at the well head. For purposes of utilization hot-water systems can be divided into three temperature ranges: above 150 degrees centigrade, possible utilization for generation of electricity; from 90 to 150 degrees centigrade, possible use for space and process heating or perhaps for electricity; and below 90 degrees centigrade, possible utilization for direct heat only in locally favorable circumstances.

2. GEOPRESSURED DEPOSITS

Geopressured resources are comprised of water and dissolved methane at moderately high temperatures, but at pressures higher than the normal hydrostatic pressure. In the United States, geopressured resources have been confirmed in sedimentary formations along the Gulf Coast. On the basis of geological information obtained from petroleum operations, the Gulf Coast geopressured resources are believed to be quite large, and there is evidence that similar geopressured formations in sedimentary basins exist elsewhere in the United States. Because, in addition to thermal energy the natural gas is also recoverable, the incentive to produce these geothermal waters is enhanced. The mechanical energy potential from depressurization has been shown to be negligible.[1]

3. HOT TIGHT ROCK DEPOSITS (HOT DRY ROCK DEPOSITS)

Hot tight rock systems consist of relatively impermeable rocks at elevated temperatures and generally lacking in naturally circulating fluids. To extract usable power, these resources require fracturing for the introduction and circulation of a heat transfer fluid. Since a large amount of geothermal energy appears to be stored in these deposits, if extraction of this heat becomes economically feasible, the Nation's geothermal energy potential would be greatly augmented.

4. MAGMA SYSTEMS

With temperatures on the order of 1,000 degrees centigrade (ranging from 600 to 1,500 degrees centigrade), deep magma sources represent large amounts of high grade energy. Live volcanoes, which may offer potential for recoverable magma energy, are located in Hawaii, the Western United States, and Alaska. However, the technical and materials problems attendant with utilization of magma systems are formidable and while the energy contained in these systems is immense, the resource is not at present considered accessible.

C. Current Contribution to U.S. Energy Supplies

Current U.S. geothermal electric power installed capacity is 663 megawatts (about one-tenth of 1 percent of the total U.S. electric power production) plus 15 to 16 megawatts of nonelectric utilization. This compares with the total world capacity of geothermally produced electricity from the 11 producing countries about of 1,760 megawatts, and total nonelectric utilization of geothermal energy

[1] White, D. E., and D. L. Williams, eds., "Assessment of Geothermal Resources of the United States—1975." U.S. Geological Survey Circular 726, 1975, 155 p.

equivalent to about 4,200 megawatts. Additional geothermal electric power capacity planned or under construction in the United States would raise the domestic geothermal electric total to around 1,300 megawatts by the end of 1982.

The major geothermal development in the United States is The Geysers dry-steam field, from which about one-half of San Francisco's electricity is produced. Applications of direct heating include the cities of Boise, Idaho and Klamath Falls, Oregon which are partially heated from nearby hot springs and geothermal wells.

D. State-of-the-Art

Geothermal exploration is in a state somewhat similar to that of the petroleum industry many years ago when exploration was a matter of drilling oil seeps. The most productive method of finding geothermal deposits is through the drilling of hot spring areas.

The technology of utilizing dry steam sources, such as at The Geysers, California, is reasonably well advanced. At The Geysers, after filters and centrifugal separators are used to remove particulate matter from the well head steam, the steam passes through insulated pipes to a power plant. Conventional condensing turbines are used to drive the generators. The turbines are designed to adjust to the comparatively low temperature and pressure of geothermal steam.

In wet steam fields, such as Cerro Prieto, Mexico and Wairakei, New Zealand, the water and steam are separated and the steam piped directly to the turbines. In addition, the hot water can be flash boiled in one or more stages and the lower pressure steam generated by flashing can also be used for power generation.

In low temperature hot water systems, heat from the geothermal water pumped from the well is used in a heat exchanger to boil a secondary fluid, such as freon or isobutane, which has a low boiling point and which then is utilized to drive a power turbine. The Paratunka electric power station in Kamchatka, U.S.S.R., was the first geothermal station to use a secondary fluid (freon). However, freon leaks have apparently been a chronic problem at this plant.[2]

While the ability to handle high-temperature, low-to-moderate salinity geofluids and to convert the heat to usable power with existing technology has been demonstrated, the use of high-temperature, high-salinity brines and moderate temperature resources will require advanced and unproven technology for economic operation.

E. Current Research and Development

Geothermal research and development projects currently funded in the United States cover a variety of problem areas. The U.S. Geological Survey (USGS) has a continuing research effort in refining and updating the assessment of domestic geothermal resources. The goal of the Department of Energy's (DOE) geothermal program is to stimulate commercial development by private industry and local public power authorities of the large but underutilized geothermal resources of the United States. The focus of this program has been on (*a*) reduction of costs and uncertainties in reservoir

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[2] U.S. Congress. House. Committee on Science and Technology. Energy From Geothermal Resources [2 Edition]. Committee print, 95th congress, 2d session. Washington, U.S. Government Printing Office, 1978, p. 26.

exploration, assessment, development and utilization; (*b*) development and demonstration of cost-effective heat exchangers for a wide range of geothermal fluids; and (*c*) development and demonstration of environmental impact control technology.

Specific projects currently include:

(*a*) Confirmation of a low temperature hydrothermal reservoir in the Atlantic Coastal Plain;

(*b*) Startup of 15 new direct heat field experiments;

(*c*) A cooperative agreement with Union Oil and Public Service of New Mexico for a 50 Mwe demonstration plant;

(*d*) Testing of a geopressured zone with a well drilled in Brazoria County, Texas;

(*e*) Identification of geopressured reservoir areas in the Wilcox formation of Texas and drilling of additional wells in the Gulf Coast;

(*f*) Construction of a 3 Mwe wellhead generator in Hawaii;

(*g*) Testing of a full-scale hydrogen sulfide control system at The Geysers;

(*h*) Field testing of explosive stimulation and hydraulic fracturing;

(*i*) Field testing of improved bits and downhole motor for directional drilling; and

(*j*) Assessing eastern hot dry rock resources.[3]

II. Prospects or Requirements for Further Development

A. Research and Development

Four general areas of research and development (R. & D.) that would benefit all geothermal resources are: resource assessment and related technology development, drilling technology, heat exchangers, and materials research. Other geothermal R. & D. needs vary according to the type of geothermal resources being considered.

1. CAPITAL

Research and development related to hydrothermal systems which are already in the stage of commercial development are primarily focused on problems that would also have application to other geothermal resources. The amount of R. & D. capital required ranges from minimal levels for further development of dry steam hydrothermal resources to hundreds of millions of dollars depending on the perceived gains (benefit to cost ratio) from improved technology and the particularly needs of each development. For example, a study prepared for the Department of Energy (DOE) has estimated that with a requirement of 10:1 benefit to cost ratio, and postulating that drilling performance savings materialize (and DOE's scenario that 8,650 geothermal wells will be drilled by 1990), then \$60 million to \$230 million could be spent over the next 8 to 10 years on a Federal R. D. & D. geothermal drilling technology program that promises to yield the postulated improvements.[4]

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[3] U.S. Congress. House. Committee on Appropriations. Energy and Water Development Appropriations for 1980. Hearings, Part 5, 96th Congress, 1st session. Washington, U.S. Government Printing Office, p. 331.

[4] Mitre Corp. Prospects for Improvement in Geothermal Well Technology and Their Expected Benefits. Prepared for U.S. Department of Energy, U.S. Government Office, June 1978, 128 p.

However, this benefit would be consideably reduced if less than optimum conditions prevail (primarily if private development is not sufficiently stimulated to drill the 8,650 wells postulated.)

In general, R. & D. capital requirements for hydrothermal systems will likely be greater for attempts to achieve economic utilization of mid- to lower-temperature resources than for higher temperature resources.

Research and development in geopressured resources includes reservoir definition studies, drilling and testing geopressured aquifers, and environmental assessment and monotoring. Current plans call for DOE to drill and test 25 production wells by 1984 and at least the same number of injection for brine disposal. Production wells are expected to cost about $4 million each to drill and $1 million each per year to test.

Potential utilization of hot dry rock systems requires a much more extensive R. & D. effort as the problems are of a different and more difficult nature. Current R. & D. efforts are toward resource definition, planning and economic studies on a national scale, and identification of experiment sites. An experimental 50 Mw thermal loop is being developed at Fenton Hill, New Mexico. Capital for R. & D. through 1990 could range from requested program funding of $14 million in fiscal year 1981 to much greater amounts depending on the problems encountered and the number of development possibilities attempted.

Development of magma systems is of a much more long-term nature and the major portion of R. & D. capital is likely to be channeled toward the other geothermal resources through 1990.

2. TIME

Given a successful effort, R. & D. to improve geothermal drilling technology is expected to begin showing benefits in the mid-1980s. If the geopressured resources element of DOE's geothermal program advances as scheduled, the R. & D. effort would lead to commercial development by 1985. Research and development in the area of hot dry rock resources is not likely to lead to commercial applications before 1990. These time frames for commercialization of geopressured and hot dry rock resources assume optimum results and are consequently minimum time frames.

B. Demonstration

1. CAPITAL

Capital requirements for demonstration plants are also dependent on the type of geothermal resource utilization attempted. Demonstration geothermal electric plants from hydrothermal resources are designed primarily to obtain data on long-term utilization of improved technology and more difficult reservoirs. The Federal contribution to capital requirements would be expected to decrease as these projects are completed and private development is stimulated. Funding requested for fiscal year 1981 was $20 million for design, construction, and operation of these facilities. At current prices a 50 Mwe geothermal demonstration plant using binary technology would cost about $50–70 million. Demonstration of direct heat applications from mid- to low-temperature hydrothermal resources is also part of the current program and is expected to decrease as designs are proven and private commercialization expands. The funding request in this program area was $16 million for fiscal year 1981.

Capital requirements for geopressured demonstration plants are expected to peak in the early to mid-1980s and to decrease thereafter. The level reached would depend on the number of demonstration plants required to adequately prove the economic viability of the resource base, assuming the current R. & D. effort is successful. Geopressured demonstration plants would likely be more costly than hydrothermal because of the increased complexity.

Also assuming a successful R. & D. effort, capital for hot dry rock demonstration plants may be required beginning in the mid to late 1980's. This capital requirement would likewise depend on the technology developed, but would likely be greater than hydrothermal or geopressured demonstration plants since this resource would be more costly to develop.

2. TIME

See A.2, above.

C. Commercialization

1. CAPITAL

Through 1990, 37 specific projects have been identified which are postulated to produce power by suitable conversion of steam, liquid-dominated hydrothermal or geopressured resources.[5] The cost of each of these projects will be a function of its size, depth and characteristics of each reservoir, type of technology employed, and inflation during the coming decade. The cost of producing the goal of 10 gigawatts by 1990 (see IV.A, below) based on known costs of developing hydrothermal deposits would be about $6.5 billion in 1979 dollars not counting the financing cost of capital or any cost of electrical generating facilities.[6] In addition, an equal amount would be required for replacement production wells and distribution facilities over the approximately 30-year operating life of each development as the resource depletes. Electrical generating and transmission costs would vary, but some perspective can be gained from the 110 MW generating facility and 38-mile transmisson line for Unit No. 16 at The Geysers, which are estimated at $68 million and $63 million respectively.[7]

The costs of producing a geopressured resource are unknown.[8] One estimate of the capital cost for a 25 Mw, double flash power plant coupled with a geopressured fuel plant was over $60 million in 1978 ($65 million in 1979 dollars using the implicit price deflator for gross national product).[9] Using this figure, 10 gigawatts of electric capacity would cost $26 billion in 1979 dollars. Estimates

[5] Mitre Corp., op. cit., p. 4.
[6] Calculation based on data in Oil and Gas Journal, Dec. 18, 1978, p. 15–19.
[7] Wall Street Journal. Mar. 4, 1980 p. 41.
[8] U.S. Congress. Senate. Committee on Appropriations. Energy and Water Development Appropriations, fiscal year 1980. Hearings, Part 5, Dept. of Energy, 96th Congress, 1st session. Washington, U.S. Government Printing Office, p. 901.
[9] Wilson, J. S. A Geothermal Power Plant. Chemical Engineering Progress, November 1977: 95–98.

for the cost of producing the associated methane from geopressured deposits have ranged from $2.50 to $10.00 per thousand cubic feet.[10]

2. TIME

Through 1982 only The Geysers field is expected to produce electric power on a commercial scale. It is assumed that liquid dominated hydrothermal would come on stream beginning in 1983.[11] Since geopressured resources are expected to contribute energy by 1986, yearly additions of power should grow slowly from 1979 through 1989 and reach a plateau for the period 1990–1995.[12] Hot dry rock resources are not expected to become significant contributors of power by the turn of the century.

3. OTHER

The industrial base and manpower requirements are not likely to be significant factors in geothermal commercialization. Material needs are also not a significant constraint in terms of quantity but may be a concern in terms of needed improvements in materials. Energy input is not likely to be a significant deterrent to hydrothermal or geopressured development, but may be significant in the case of hot dry rock resources.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

Because of high-temperature and salinity, reliable pumping of geothermal fluids at depth (as required to control wellbore chemistry and increase fluid extraction rates to commercial levels) has not been attained. Without dependable downhole pumping only the highest temperature resources can be commercially developed.[13] Another major technical barrier is inability to reliably predict reservoir capacities, lifetimes, and production characteristics. This is a major barrier to commitments by utilities and financial institutions. A potential obstacle to hydrothermal resource development is the difficulty in managing the brine and controlling its chemistry in order to minimize plugging of the formation during reinjection. This adds to uncertainties about the economics of use.

Development at The Geysers has been slowed by lack of successful demonstration of hydrogen sulfide abatement technology. This is a major problem which is being worked on, but may be a problem for only a few geothermal energy sources in the United States. However, near-term development at The Geysers, which is the premium U.S. geothermal resource, is critical to the growth of the industry.

An obstacle to development of direct heat applications is the difficulty in quantifying the cost and reliability of heat transfer equipment because of the lack of operating experience.

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[10] U.S. Congress. Senate. Energy and Water Development Appropriations, fiscal year 1980, op. cit., p. 901.

[11] Mitre Corp., op. cit., p. 4.

[12] Ibid.

[13] DOE, Draft Commercialization Strategy Report for Hydrothermal Electric and Direct Heat Application, TID-28840, 1978, p. 55.

B. Economic

The high cost of drilling wells and constructing gathering systems is a potential obstacle to the implementation of geothermal technology. This factor dominates power costs and makes a large fraction of the resource noncompetitive with other energy sources (under current technology and tax laws). In the absence of other incentives, developers would concentrate on high temperature resources which offer more promise of economic return rather than low-to-moderate temperature resources. An obstacle, particularly for small resource companies, is raising front-end capital for exploration and development. Because of the small individual unit size (50 to 100 Mwe) and incremental pattern of reservoir development, another economic obstacle to development of remote or small reservoirs is transmission line costs and availability.

Economic uncertainty arising from technical and institutional uncertainties is an obstacle to accelerated geothermal development. Normal financing of powerplants is not readily available to utilities because of currently perceived high risks of unproven technology. Since there are no operating flash-steam plants or binary plants, utilities would be hesitant to invest in these technologies.

C. Environmental

Competing land uses and priorities coupled with limited data on the impacts of geothermal energy development make surface management agencies reluctant to permit geothermal development.[14] Most high temperature resources are in relatively primitive or undeveloped areas. Major conflict could well arise with preservation of the undeveloped character of these lands. Restrictive regulation may result from concerns for the protection of fresh water aquifers from possible contamination by geothermal fluids. Limited data exist on effects of geothermal fluid withdrawal on subsidence. This concern could also be a potential environmental obstacle slowing development.

D. Social

State public utility commissions tend to view geothermal powerplants as unproven technologies. As a result, only limited R. & D. funds are allowed to be included in the utility rate base. Lack of an infrastructure to bring together complementary teams of developers, users, and financial institutions also can delay geothermal development. Absence of public education and information dissemination has resulted in few industries, organizations, communities, and other potential market participants being made aware of geothermal opportunities and potential benefits of direct heat applications.

E. Political

Lack of explicit treatment of geothermal applications, particularly direct use, in existing laws dealing with energy resources has impeded development. Problems exist with regard to resource definition for ownership rights, relationship to water law, leasing and

[14] DOE. Draft Commercialization Strategy Report for Hydrothermal Electric and Direct Heat Application, p. 57.

regulatory authority, and property and severance taxes, and other aspects of State and Federal laws.[15]

F. Competing Uses for Available Equipment

Geothermal developers must compete for drilling rigs and other equipment needed in oil and gas exploration. This is an obstacle to geothermal development as oil and gas generally offer promise of greater economic return.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

The potential contribution of geothermal energy to total U.S. energy supplies depends on a number of interdependent factors. Engineering research, if successful, can probably accomplish the technical objectives in a timely fashion. However, institutional barriers such as tax and legal uncertainties, and leasing, regulatory and permitting procedures must also be breached. Finally economic returns must be demonstrably sufficient to stimulate the large amount of private investment needed for geothermal development. It is estimated that if the current Federal geothermal program is successful, electric power generating capabilities will be as much as 3 to 4 gigawatts by 1985, and 10 by 1990.[16] Expected capacities for direct thermal applications are 0.1 to 0.2 quads/year by 1985, and could be twice that level or more by 1990. In addition, it is anticipated that commercial production of geopressured methane will amount to as much as 0.02 quads per year by 1985.[17] Since development of geopressured resources is expected (by DOE) to increase considerably after 1985, recovery of associated methane would also increase.

The 1985 time frame estimates would appear to be fairly realistic since they are primarily based on conventional geothermal resources utilization, much of which is currently planned. However, to attain the levels estimated by 1990, significant advances in geopressured development would be required.

B. Contribution by 2000 or Beyond

Estimates developed by DOE for electric power production from geothermal resources range from 20 to 40 gigawatts by the year 2000 and from 70 to 140 gigawatts by 2020.[18] Direct heat applications are estimated to amount to 0.5 to 2 quads per year by 2000 and between 6 and 8 quads per year by 2020. In addition, DOE estimates that geopressured methane recovery could yield 2 to 4 quads per year by 2000 and 16 to 28 quads per year by 2020.[19] To put this in perspective, the geothermal production levels envisioned

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[15] DOE, Draft Commercialization Strategy Report for Hydrothermal Electric and Direct Heat Applications, p. 66.

[16] Interagency Geothermal Coordinating Council. Geothermal Energy, Research, Development and Demonstration Program, Second Annual Report, DOE/ET-0039/1 IGCC-3, April 1978, 121 p.

[17] U.S. Congress. House. Committee on Appropriations. Energy and Water Development Appropriations for 1980. Hearings, Part 5, op. cit., p. 330.

[18] Ibid.

[19] Ibid.

by DOE by the year 2020 would displace 20 to 45 million barrels of oil per day. The higher figure is over twice the current daily petroleum consumption of the United States. Hence, attainment of these levels of geothermal energy production by the year 2020 appears highly unlikely, especially considering the potential availability of other energy sources by that time. Furthermore, considering the recent findings of DOE's geopressured drilling program (where higher than expected salinities have been encountered, keeping methane concentrations low), many experts now suggest that even modest hopes for geopressured geothermal energy will be difficult to fulfill.[20]

While geothermal energy is a potentially useful source of energy, it is restricted to the areas in which suitable temperature anomalies occur. Furthermore, considering the technical and economic barriers it faces, geothermal and geopressured energy development would appear unlikely to become a major source of energy before the end of the century. A crash program to bring these resources on stream could have several outcomes. First, it could speed up the process of technology development. If the economics of producing geopressured or hot tight rock deposits were favorable, the crash program could pay off. However, the economy of developing these resources may not be favorable (long-term energy output per well too low) and, thus, the crash program would only result in a shortened period of uncertainty before the economic data were available.

Putting the necessary resources and materials into a crash program for geothermal development would likely necessitate, to some extent, their removal from related areas such as oil and gas exploration and development, and enhanced oil recovery. In an extreme case this could possibly lead to a net short-term decrease in energy production. However, if the program were successful, an increase in energy supply over the long-term might be expected.

A recent energy supply and demand study by the National Academy of Sciences (CONAES study) projected that geothermal energy in the most favorable or national commitment scenario (such as might be envisioned through a crash program) could contribute 8.24 quads by 2010.[21] Conservatively discounting this by one-third or roughly the contribution from the more difficult hot tight rock and magma sources, a reasonable projection of maximum geothermal energy development in 2010, as from a crash program, might suggest a level on the order of five to six quads. At current prices this level of production would cost roughly $3 billion to $4 billion, not counting the financing cost or cost of any electrical generating facilities.

[20] Science, vol. 207, Mar. 28, 1980, p. 1455–1456.

[21] National Academy of Sciences. Energy in Transition 1985–2010. Final Report of the Committee on Nuclear and Alternative Energy Systems, National Research Council, Washington, D.C., 1979, 783 p.

HYDROGEN *

I. Survey of the Current Situation

A. Description of the Technology

Hydrogen is now produced from water, natural gas, or coal. Future concepts involve producing hydrogen from water, with energy being consumed in order to dissociate the water molecule into hydrogen and oxygen. In commercial use, hydrogen would be distributed through pipelines and then recombined with oxygen to produce water, thus liberating energy which would be used to replace conventional fuels for heating and cooling, transportation, and industry. The use of hydrogen, therefore, is primarily a method for the storage and distribution of energy that is generated by other means. In this way it is comparable to electricity, which is our present method of distributing large amounts of power.

Some hydrogen advocates foresee, as a long-term goal for the development of hydrogen energy, the concept of a "hydrogen economy" in which water would be separated into hydrogen and oxygen, using a non-fossil fuel energy source, such as nuclear or solar energy. The hydrogen produced in this manner would then be transported through pipelines and burned to provide fuel for various needs (e.g., transportation, industry, heating, and cooling). Since the burning of hydrogen involves combining it with oxygen to produce water, a "hydrogen economy" would actually comprise a huge closed system where (*a*) hydrogen and oxygen are separated out from water, with expenditure of energy being required, and (*b*) hydrogen is recombined with oxygen to form water, with a release of useful energy taking place. This concept is envisioned by some as a replacement for many existing energy sources and much energy-consuming equipment.

B. Know Resources and Reserves

The potential supply of hydrogen is almost infinite, as each molecule of water on Earth is one-ninth hydrogen by weight. The difficulty lies in separating the water molecule into hydrogen and oxygen.

C. Current Contribution to U.S. Energy Supplies

The use of hydrogen as a fuel today is limited to experimental applications, with no major impact on the existing energy situation.

D. State-of-the-Art

Hydrogen for industrial uses is produced to day primarily by steam reformation of natural gas. Hydrogen can also be obtained from coal, using known coal gasification technology. The produc-

*Prepared by Migdon Segal, analyst in energy technology.

tion of hydrogen from water, however, is not yet economically practical because of the high cost and low efficiency of existing electrolytic and thermochemical methods.

As for the use of hydrogen, a hydrogen-powered bus has been developed, and a demonstration house that meets all of its energy needs with hydrogen has begun operation.[1]

Liquid hydrogen has been used in large quantities (more than 100-billion cubic feet total) in support of the space program. Liquid hydrogen storage has been practiced in volumes of up to a million gallons. The design requirements of constructing pipelines for the transmission of gas are well understood, and the practices and codes for doing so have been developed. However, the tendency of hydrogen to leak through and "embrittle" pipeline walls would still be of concern.[2]

E. Current Research and Development

The Department of Energy (DOE) funds hydrogen research under a number of separate programs, and it is not a "line item" in the budget. Funding appropriated for this purpose for fiscal year 1980 was $23.1 million (estimated). For fiscal year 1981, the Administration's request for funding was approximately $23 million.

The DOE subdivides its hydrogen research into three broad categories: production, storage and transport, and conversion (i.e., use for energy). At present highest priority is given to the production area, since this area includes the most difficult technological obstacles, and since the storage, transport, and conversion technologies will not be usable if economic processes for the production of hydrogen are not developed.

II. Prospects or Requirements for Further Development

A. Research and Development

Research and development regarding the use of hydrogen as a fuel is needed in three major areas, as follows:

1. HANDLING AND STORAGE

Hydrogen is one of the most difficult of all materials to handle and store. As a gas, its low density makes bulky, high-volume containers necessary (or alternatively, very high pressure containers), and it tends to leak through container walls and may even attack those walls through the phenomenon known as "hydrogen embrittlement." This phenomenon is not well understood, and the degree of severity is in doubt. However, according to DOE, hydrogen may be passed through existing natural gas pipelines, mixed with natural gas, without significant leakage or embrittlement at a somewhat lower pressure than is normally used in those pipelines.[3] As a liquid, hydrogen requires cryogenic temperatures close to absolute zero that are difficult to maintain. As a metal hydride (a chemical compound formed by reacting hydrogen with certaifn

[1] Developments by Billings Energy Corp., Provo, Utah.

[2] The safe distribution and handling of hydrogen for commercial application. F. A. Martin, Union Carbide Corp., Linde Division, 7th IECEC, 1972, pp. 1335–1341.

[3] Telepbone conversation with Dr. James Swisher, DOE, May 1980.

metals), hydrogen is somewhat more manageable than it is in the gaseous or liquid forms. However, the quantity of metal required makes metal hydride storage of hydrogen costly in terms of weight load (particularly damaging for use in an automobile), and in terms of consuming metals resources.

2. ENERGY LOSS IN HYDROGEN FORMATION

There is a sizable loss of energy in the hydrogen cycle, which involves using energy to dissociate hydrogen from the water molecule, then recombining hydrogen and oxygen to form water and obtain energy. The energy obtained in such a cycle can never be as much as the energy expended. An early estimate was that 6 Btu of electricity would be required for each Btu of electricity generated from hydrogen.[4] The DOE contends that this ratio is excessively high, and that the efficiency of existing processes for producing hydrogen from water is 65–70 percent, i.e., 3 Btu of electricity would produce 2 Btu of usable energy from hydrogen. Future technologies promise 85 percent efficiencies.[5] Waste heat may be used to decompose the water molecule thermally, and the high temperature needed (2,500 to 3,000 degrees C) for direct thermal decomposition may be lowered by various "thermochemical" schemes where the decomposition takes place in a series of steps, which lower the temperature needed to perhaps 730 degrees C. The question of whether the energy loss can be kept within acceptable levels remains to be resolved.

3. MOTOR VEHICLE USE

The use of hydrogen as a motor vehicle fuel is virtually impossible at this time because of materials, size, and weight handicaps. The best of the proven metal hydrides, iron-titanium, would require hundreds of pounds of metal to hold enough hydrogen to equal the fuel capacity of a 20-gallon gasoline tank. This would greatly increase the weight and metal content of an average car and, if such vehicles were used in large numbers, it would strain supplies of both iron and titanium. Experimental work is under way to find lighter-weight metal hydrides which would be inexpensive and readily available. if such materials can be found, the use of hydrogen for automotive purposes may become feasible.

B. Demonstration

Demonstration projects do exist with regard to the hydrogen-powered bus and hydrogen-powered home previously mentioned. Other demonstration projects would presumably be needed as R. & D. in hydrogen use advances, particularly with regard to the low-cost production of hydrogen, its transportation and storage (without significant leakage), and its practical use in motor vehicles and other energy-consuming applications.

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[4] Telephone conversation with G. Strickland, Brookhaven Laboratory, and our own calculation, 1975.

[5] Telephone conversation with Dr. James Swisher, DOE, May 1980.

C. Commercialization.

Hydrogen as a fuel has not reached the point in its development where reliable judgments as to the capital, time, manpower, and other requirements needed for its commercialization can be made.

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

The technical obstacles to the development of hydrogen as an energy source have been enumerated previously. Briefly, they include (*a*) the need for production of hydrogen from water in an energy-efficient manner, (*b*) the development of lighter metal hydrides to use as hydrogen "storage tanks" in automobiles, as opposed to the present iron-titanium hydride which requires some 3,200 pounds of metal to hold enough hydrogen to equal the fuel capacity of a normal automobile gas tank, and (*c*) the need for low cost materials which can be used for hydrogen storage containers and hydrogen transmission pipelines without experiencing excessive leakage or embrittlement.

B. Economic

Analyses of the economics of hydrogen as an energy source are in their early stages. One representative study, commissioned by DOE, showed that hydrogen produced through coal gasification might be economical in chemical applications (e.g., for production of ammonia) by the late 1990's, as natural gas prices rise more rapidly than coal prices. As for hydrogen produced through electrolysis of water, the major constraint on its development was said to be the availability of low cost electricity. The first sites for water electolysis to produce hydrogen were expected to be low hydro sites, where electricity costs would be the lowest. Later, electricity for this purpose could be produced from nuclear power plants. Projections indicate that significant amounts of power at off-peak cost for this purpose will not be available until the late 1990's. As the price of natural gas rises, full cost electricity from nuclear plants could become competitive as a source of hydrogen for small scale uses. Electrolysis and coal gasification were said to be complementary and not competitive as technologies for producing hydrogen, with electrolysis better suited to hydrogen production for small scale uses while coal gasification might be better suited for large-scale production. Also, electrolysis might be the method of choice for the Northeast and the West, while coal gasification would be used in other areas of the country where coal resources are present.[6]

C. Environmental

The use of hydrogen has many environmental advantages. Hydrogen is clean burning, with water the only combustion product. It use to replace conventional fuels would be beneficial, particularly in a high-pollution urban area.

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[6] Economics and market potential of hydrogen production. Study performed for U.S. Department of Energy, Division of Energy Storage Systems, by Hittman Associates, Inc., Columbia, Md., September 1978.

D. Social

Large-scale use of hydrogen in the energy system would have major social and political implications. In its most extensive form, the "hydrogen economy" would replace many existing forms of energy distribution and storage, and the societal adjustments this would entail would be major. In the executive summary of the final report on an NBS-sponsored "Workshop on Societal Aspects of Hydrogen Energy Systems," it was stated that:

> The dominant role of sociopolitical factors transcends hydrogen. Introduction of any new (energy) technology implies change in existing institutions; and institutional change rests upon societal "facts" (values, perceptions).

The summary goes on to state that large scale use of hydrogen as a fuel would depend on such factors as internalization of costs, government action on incentives and regulations, and goal-oriented planning.[7]

E. Political

The political aspects of a shift from existing energy sources to a "hydrogen economy" would be similarly extensive. Hydrogen would presumably be a political "plus", because of its potential for replacing petroleum-based fuels (e.g., gasoline as an automotive fuel), and its clean burning characteristics which would diminish the air pollution problem in urban areas. Possible problems would include the siting of large nuclear or solar plants where the energy to produce the hydrogen from water molecules would be generated.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

No significant contribution from hydrogen is likely by 1990. In order for hydrogen to be used in a major way, the production and materials problems mentioned previously would have to be solved in the near future. Also, in order to implement the "hydrogen economy" concept, hydrogen would have to be produced from water at a sea or lakeshore facility, using an energy source such as nuclear or solar energy. At this time it does not appear likely that advanced nuclear or solar energy development will have progressed to the point where such applications are feasible by 1990, given the present difficulties associated with both of these energy sources.

B. Contribution by 2000 or Beyond

For the distant future, the theoretical possibilities for hydrogen as a fuel are limitless, given the abundance of water from which hydrogen can be obtained. The question then becomes whether hydrogen energy systems will be competitive with the alternatives which may be available by that time. The DOE, in its report entitled "Economics and Market Potential of Hydrogen Production," declares that information based on computer modeling of future energy scenarios suggests that the use of hydrogen as a fuel

[7] Currie, L. A. and Kropschot, R. H. Hydrogen: a Workshop on Societal Aspects of Hydrogen Energy Systems. Sponsored by National Bureau of Standards and 5 other agencies. Reston, Va., June 4–7, 1978. (Executive Summary.)

would be quite limited before the year 2020.[8] It does not address the question of post-2020 development.

[8] U.S. Department of Energy. Division of Energy Storage Systems. "Economics and market potential of hydrogen production." (Report No. ANL-4409-1). Prepared by Hittman Associates, Inc., Columbia, Md.

LOW-HEAD HYDROPOWER *

I. Survey of the Current Situation

The energy crisis has rekindled interest in development of new hydroelectric facilities and improvement of existing ones. In particular, the idea of installing small units on minor rivers and tributaries has become popular, and many previously developed sites, now abandoned, offer possibilities for augmenting the Nation's electrical energy needs. Hydroelectric projects can be attractive because they utilize a renewable resource and produce electric power over long service lives without consuming depletable fuel resources in the process, although they can also have adverse environmental and other impacts.*

A. Description of the Technology

A hydroelectric project may harness either the potential energy of a river's gravitational fall or the kinetic energy of its motion to produce electricity. In the first case, water may be stored behind a dam—the reservoir area is called the forebay and the surface of the forebay is called the headwater elevation—and released at desired intervals through a conduit called a penstock or power intake. The penstock directs the water to a turbine-driven generator below the dam. Water is released from the turbine into an afterbay, the surface of which is referred to as the tailwater level. The force exerted by the water on the turbine blades drives the turbine, which in turn drives a generator to produce electricity. The energy producing potential of a system depends on the height of its head—the difference in elevation between the headwater and tailwater. In the second case, run-of-the-river dams, unlike reservoir facilities, rely on the naturally flowing river water to produce power. However because weather and the seasons alter river flow, run-of-the-river dams are not always reliable suppliers of power.

B. Known Resources and Reserves

The total physical hydropower resource for the United States is estimated to exceed 512,000 megawatts (Mw) of capacity with an average annual energy generation greater than 1.4 trillion kilowatt-hours (kwh), according to a preliminary study released by the Corps of Engineers.[1] This comprises existing hydropower as well as estimates of incremental and undeveloped conventional hydroelectric power potential. The study found a total of almost 64,000 Mw of installed capacity at 1,252 existing hydropower facilities currently generating an average of over 280 billion kwh of electric energy per year. There are 5,424 existing dams, some of which are generat-

* Prepared by John Justus, specialist in Earth sciences.

[1] U.S. Department of the Army. Corps of Engineers. Institute for Water Resources and Hydrologic Engineering Center. National Hydroelectric Power Resources Study: Preliminary Inventory of Hydropower Resources. Washington, July 1979, 6 volumes (various paging).

ing power at present, identified as having the physical potential for new incremental power development, i.e. adding hydropower plants or increasing hydropower output with upgraded equipment. The full development of this incremental potential could yield an additional capacity of almost 95,000 Mw with an average annual energy generation exceeding 223 billion kwh. This represents an estimated savings in oil consumption equivalent to about one million barrels per day.[2] While the physical potential for this increase is clearly available, some of these projects might not satisfy more detailed economic analysis as well as the institutional and environmental criteria which might be imposed upon them.

There are 4,532 potentially feasible undeveloped sites which, if fully developed for hydropower, could yield approximately 354,000 Mw with an estimated average annual energy generation greater than 935 billion kwh, representing an estimated savings in oil consumption equivalent to 4.3 million barrels per day. Many of these sites have less chance of acceptance than the modification to existing projects because of the potentially more adverse environmental and institutional effects. Furthermore, 47 percent of this undeveloped potential is located in Alaska where it might be economically difficult to develop and transmit the power to potential users.[3]

Of the Nation's existing hydroelectric power sites, large-scale facilities (25 Mw and larger), particularly those located in the Pacific Northwest and the Southwest regions, account for approximately 92 percent of the capacity and the energy generation. Small-scale facilities (15 Mw and smaller) account for about 5 percent of the Nation's installed hydro capacity and hydroelectric energy, and there are 5,655 of these small dams which are either generating power or have the potential for incremental development. The installed capacity at existing small-scale facilities is estimated at almost 3,000 Mw with an average annual energy generation exceeding 15 billion kwh. Full incremental development of other potentially feasible, existing small-scale projects could more than double this output by adding another 5,400 Mw of capacity and 17 billion kwh (77,600 bbl/day equivalent) of energy to the total. In addition, 2,642 potentially feasible, undeveloped sites were identified which could provide an estimated capacity of about 8,000 Mw and more than 28 billion kwh (127,800 bbl/day equivalent) of average annual energy generation.[4]

C. Current Contribution to U.S. Energy Supplies

Conventional hydroelectric developments make up slightly more than 15 percent of the electric generating capacity in the United States. This corresponds to a total of 64,000 Mw of installed capacity at 1,251 sites producing an average of over 280 billion kwh of electrical energy per year.

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[2] One barrel of oil=600 kwh at the point of consumption. Corps of Engineers, op. cit.
[3] U.S. Department of the Army. Institute for Water Resources and Hydrologic Engineering Center. National Hydroelectric Power Resources Study, vol. 1, p. 13.
[4] Ibid., pp. 7-13.

D. State-of-the-Art

Using flowing water to generate electricity has been practiced commercially in this country since the 1880's, when small dams first supplied power to mills, factories, and nearby towns. However, hydroelectric development in the United States has for four decades focused on large-scale projects. Small facilities of the sort employed extensively by Japan, Switzerland, Sweden, and China have remained largely undeveloped in the United States and, where they did exist, many small hydropower plants were abandoned over the years in favor of large, centralized, fossil-fueled, steam electric plants. The economic rationale for abandoning low-head hydro plants—high costs for operating personnel, efficiency considerations, variability of the resource—seemed correct when decisions were made. However, subsequent changes in the technology and the relative economics of small hydropower plants have prompted a reexamination of the issues, and it now appears appropriate to assess the status and technological prospects for small scale hydropower as well as the rehabilitation and/or augmentation of existing hydropower facilities of all sizes.

E. Current Research and Development

In May 1977 the Energy Research and Development Administration (ERDA) established the low-head hydroelectric program and assigned its management to the Division of Geothermal Energy. During the remainder of fiscal year 1977 program planning and resource assessment activities predominated. Cooperative arrangements were established with the Corps of Engineers and the Bureau of Reclamation (Department of the Interior) to strengthen their low-head programs and avoid duplication of capabilities.

In fiscal year 1978, with the formal authorization of the program by Congress and an appropriation of $10.0 million, various projects were initiated: cost-shared projects to carry out site-specific engineering and economic feasibility studies, development of advanced technological concepts, improved resource assessments, and analyses of institutional barriers slowing commercialization. The program was transferred in October 1977 to the U.S. Department of Energy (DOE). The fiscal year 1979 appropriation included $28.0 million to begin an industrial development program encouraging turbine standardization, expand regional resource assessments, and facilitate the license application process.

The fiscal year 1980 DOE appropriation contained $18.0 million for use in funding feasibility study loans and providing appropriate technical and institutional assistance to prospective dam developers. Economic, environmental, legal and institutional studies were continued in fiscal year 1980 to identify barriers to hydro development and if possible, eliminate them. The technical development program to reduce hydro design, construction, operation and maintenance costs was scheduled for completion.

The fiscal year 1981 budget included a request for $18.2 million to funding DOE cost sharing of small hydro construction projects, fund feasibility study loans, and further expand the hydropower resource development outreach program.

The largest share of funding has gone to feasibility studies and demonstration projects. In fiscal year 1978 DOE awarded, under competition, $2.9 million in grants for fifty seven proposals to determine the feasibility of installing hydroelectric generators at existing dams less than 65 feet high and with generating capacity less than 15 Mw in 30 States and Puerto Rico. In fiscal year 1979, the Department selected seven existing hydroelectric projects from applications submitted in response to a competition announced in June 1978. The grants, totaling $4.2 million, were used to install or improve the generating facilities at these existing dams in seven States. On June 22, 1979 DOE mailed a program opportunity notice to some 3,000 organizations and individuals inviting proposals to install and operate small hydroelectric plants at existing dams, with no limitation on height but with a generating capacity less than 25 Mw. Fifteen grants amounting to $16 million were awarded in response to this competition.

The DOE's widening program of financial assistance to test the feasibility of small-scale hydropower nationwide is being augmented by the technical services and financial resources of six other Federal agencies under the President's program of Rural Energy Initiatives. The purposes of the program are to identify possible projects for small hydroelectric development, test their engineering and economic feasibility, and if feasible, assist and encourage their development. The Bureau of Reclamation, Rural Electrification Administration, Department of Housing and Urban Development, and Community Services Administration agreed to earmark portions of their respective resources to provide $300 million in grants, loans and loan guarantees to stimulate construction of up to 100 projects by the end of 1981, adding approximately 300 Mw of capacity (assuming an estimated average installed capacity of 3 Mw at each site).

II. Prospects or Requirements for Further Development

A. Research and Development

Although low-head hydro is a well developed technology, the lack of new projects since World War II lends it the flavor of an emerging technology. Revitalization is the target: revitalization of the technology, of the industry to support it, and of interest among potential developers, including utilities, municipalities, individuals, small companies, and others who may own dams. Heavy Federal support has characterized the early steps in this direction. Engineering research and development have focused on reducing the cost of small-scale hydro equipment—a major obstacle to further development. Large hydro plants are custom designed to extract the maximum possible amount of energy out of a streamflow. At the present time, small plants are built the same way, and custom design means custom price. The cost of custom engineering for a small hydro project has been found to equal the cost of the equipment and add about a year to a job's schedule.[5] The picture is

[5] Units May Slash Small Hydro Costs. Engineering News-Record, v. 202, no. 4, Jan. 25, 1979: 21.

changing, however, and manufacturers are starting to provide standardized designs. A line of standardized 50-kw to 5 Mw hydroelectric turbine-generators is now being marketed that may cut the cost of developing low-head flows at existing dam sites by as much as 50 percent.[6] This equipment is said to be deliverable within nine months in any one of 10 pre-engineered packages of equipment for generating electricity at low-head sites.[7] [8]

In addition to refinement of turbine-generator technology, an evaluation of the state of civil works technology is necessary to determine areas most susceptible to cost reduction through simplification and standardization. This would be followed by a program to achieve cost reduction techniques and practices for an entire hydro facility system.

A broad variety of environmental and hydrological information is required for further development because decision makers generally lack understanding of the size of the potentially exploitable hydro resource base. Studies by the Corps of Engineers, Bureau of Reclamation, regional river basin commissions and councils, and DOE contractors are providing information to define the potential of existing sites. The New England River Basins Commission has assessed New England's hydro resources,[9] and with DOE support, State planning groups in Washington, Oregon, and Idaho have evaluated resources in those States. Using State funds, New York and Pennsylvania have developed similar information. Surveys of Southern, Western, and Midwestern States would be beneficial.

B. Demonstration

Most potential small-hydro developers (those who own dams) are relatively small entities (individuals, small companies, municipalities, municipal utilities) who need help to surmount the financial and institutional obstacles inherent in developing a dam for hydroelectric power production. From their perspective front-end costs are high, both to determine if a site is feasible and to purchase capital equipment, and the license and permitting process is often complex.[10] In accordance with Title IV of the Public Utility Regulatory Policies Act of 1978 (Public Law 95–617), $10 million for fiscal year 1979 and 1980 was authorized and appropriated for direct Government cost-sharing loans to evaluate dam sites with projected capacities of 15 Mw or less and apply for necessary Federal, State, and local permits. Loans are forgiven where the Secretary of Energy concludes, on the basis of the study, that the proposed project has proved to be not feasible for small-scale hydroelectric development. If proved feasible, a developer would then be obligated to repay the loan when the hydro site starts producing power. This law also contains a provision in Title IV directing the Secretary of Energy to make Government cost-sharing loans to cover architectural, engineering, and construction costs. One hun-

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[6] Claims made by the marketer, Allis-Chalmers Corp., Milwaukee, Wis.

[7] Ibid.

[8] Low-Head Hydro Lures $1-Billion Market. Engineering News-Record, v. 203, no. 13, Sept. 27, 1979: 20–21.

[9] Potential for Hydropower Development at Existing Dams in New England; NERBC Hydropower Expansion Study. Boston, New England River Basins Commission and U.S. Army Corps of Engineers (New England Division), 1980, 8 volumes (various pagings).

[10] See, generally, Proceedings of the Mid-Atlantic Conference of Legal and Institutional Obstacles and Incentives to Small Scale Hydroelectric Development. Washington, D.C., May 4–5, 1979. Sponsored by Energy Law Institute, U.S. Department of Energy, and the National Conference of State Legislatures. Concord, Franklin Pierce Law Center, 1979, 27 p. plus appendixes.

dred million dollars for each of fiscal years 1979 and 1980 was authorized but never appropriated. Eligible projects are limited to existing dams, only to projects for which necessary licenses and approvals have been granted, and to projects having neither significant adverse effect on any other use of the water utilized by the proposed project.[11] The availability of loan money is expected to stimulate owners and developers to undertake feasibility studies.

To deal with ordinary caution or skepticism, an experience base for modern small-scale hydro applications is required so that decision makers can convince themselves of its advantages. The DOE through its Program Opportunity Notice is sharing with developers the cost of rehabilitating existing dams for hydropower to demonstrate that the concept is commercially viable (supra). The current centerpiece of the program is the Idaho Falls Demonstration project. The DOE is helping the city of Idaho Falls rebuild and expand three hydroelectric dams damaged in the collapse of the Teton Dam several years ago. The three dams were formerly rated at a total of 7.4 Mw of installed capacity. When completed in late 1981, each will have an installed capacity of 8 Mw.

C. Commercialization

Because hydroelectric power technology is a mature technology and is commercially available, and because the Federal small hydro program in its present form is almost totally a commercialization program, many of the activities mentioned below are already underway.

In a 1978 DOE report, the Federal effort in commercialization was characterized as providing a push to get economically feasible projects underway. At the same time, the program seeks to remove barriers to commercialization in order to bring increasingly larger numbers of projects to a point of economic attractiveness. The Federal commercialization strategy suggests a 5-year push, scaling down to a small maintenance program by 1984. Several elements comprise the commercialization profile, as discussed below.[12]

1. TECHNICAL READINESS

Hydro technology is commercially available for deployment. Turbine/generator manufacturers and several specialty rehabilitation companies stand ready to refurbish machinery at retired hydro power dams having idle turbines and generators in place. Manufacturing industries in the United States and abroad are prepared to furnish conventional turbines, generators, equipment, and switching/intertie gear for sites not previously used for hydro power. Packaged units have been extensively used overseas, and standardized, preengineered turbomachinery packages have recently entered the U.S. marketplace (supra.). Increased competition among consultants and U.S. manufacturers might be beneficial in lowering costs. There is also a need for small hydro developers to work

[11] U.S. Congress. Committee of Conference. Public Utility Regulatory Policies Act; Conference Report to Accompany H.R. 4018. Oct. 6, 1978. [Washington, U.S. Government Printing Office] 1979, p. 41–44. (95th Congress, 2d session. Senate. Report no. 95–1292.)

[12] U.S. Department of Energy. Commercialization Strategy Report for Small-Scale Hydroelectric Power. Draft Report Prepared for DOE Overview of Technology Commercialization Assessment. November 1978. Washington, U.S. Government Printing Office, 1978, 23 p. (TID–28841.)

with utilities to encourage support for the development of decentralized sites. This is a problem with many other emerging renewable energy technologies, but hydro is likely to come online first and may have to establish the necessary precedents. Cost reductions in civil works rehabilitation practices through development of cost savings techniques are a necessary condition to commercialization.[13] [14]

2. ECONOMICS AND FINANCING

Economics of small-scale hydro projects are highly site specific. In addition to capital costs per installed kilowatt, critical variables include capacity factor, head weight, size of installation, and sale price of power produced. With regard to the last item, construction of many small-scale hydro projects could be discouraged by low prices they can command for the surplus power they generate. This situation could be alleviated if investor owned utilities could be persuaded to pay realistic fuel replacement costs for electricity, and if levelized power purchase could be encouraged.[15] Financial barriers to small-scale hydro consist of high capital cost for construction, a cash flow gap that exists in the early operating years of many projects, and cost of undertaking feasibility studies. Various information and technical programs are directed at establishing cost-reducing technologies and practice (supra.). The Federal commercial demonstration program could be used as a vehicle to promote the use of standardized turbomachinery and civil works cost reductions. Other Federal incentive programs might include an investment tax credit for hydroequipment and structures.

For example, Title II, Sections 221 and 222, of the recently-passed Crude Oil Windfall Profit Tax Act of 1980 (Public Law 96–223, 94 Stat. 229, Apr. 2, 1980) qualifies investments in hydroelectric generating facilities of less than 125 Mw installed capacity for an 11 percent business energy investment tax credit through December 31, 1985. This 11 percent energy tax credit is available both at sites where there is no present generating capacity and at sites where there is existing capacity. The amount taken into account as a qualified investment is progressively reduced in accordance with a credit cap phaseout formula as the installed generating capacity increases from 25 to 125 Mw. At 125 Mw the energy credit is phased out entirely.[16] Section 242 of the act exempts from Federal income tax through 1985 the interest earned on industrial development bonds (IDB's), the proceeds of which are used to finance hydroelectric facilities of less than 125 Mw installed capacity. Qualified facilities include sites where there is an existing dam or sites at which electricity is to be generated without any dam or impoundment of water. The cost of a qualified hydroelectric generating facility may be financed in its entirety with the proceeds from tax exempt IDB's if the total installed capacity does not

[13] Ibid.

[14] Mitchell, Allan G. Pricing Electric Power From Small Hydro-electric Plants. Paper presented to Conference on Current Federal Developments in Hydropower Licensing, Power Pricing, and Financing. Washington, D.C., Feb. 19-20, 1980. National Alliance for Hydro-electric Energy, Washington, D.C., 11 p.

[15] Section 210 of the Public Utility Regulatory Policies Act (PURPA) of 1978 (Public Law 95–617) now requires utilities to pay qualified small power producers the full costs avoided by obtaining the energy from the small power producer. The PURPA regulations define the phrase "avoided costs" as follows: "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase of from a qualifying facility or facilities, such utility would generate itself or purchase from another source."

[16] U.S. Congress. Committee of Conference. Crude Oil Windfall Profit Tax Act of 1980; conference report to accompany H.R. 3919. Mar. 7, 1980. [Washington, U.S. Government Printing Office] 1980, p. 35–38, 42, 125–128. (96th Congress, 2d session. House. Report No. 96–817.)

exceed 25 Mw. However, the maximum amount of bond proceeds that can be committed to finance a qualified facility is limited in a manner similar to the tax credit cap by a phaseout formula as the installed capacity increases from 25 to 125 Mw. At 125 Mw, the project is no longer eligible for tax-exempt IDB financing.[17]

Capital intensive, low-operating cost projects tend to generate low cash flow in early years of operation. Cash flow increases as the sales price of power escalates, but for many projects cash flow could be inadequate to handle interest requirements at the outset of commercial operations. A loan guaranty program could be designed to resolve early cash flow deficits. Such a program would allow the developer to finance a project with a loan sufficiently in excess of project requirements in order to meet interest obligations in the early operating years of the project. The Federal Government would guarantee the loan and interest payments. Because the power sales of a given project tend to increase, most default situations would tend to be self-correcting. Finally, though many projects could be inhibited by inability or unwillingness to spend more or less than $60,000 for a feasibility study, the DOE grant program to provide financial assistance for feasibility studies proved effective in fiscal year 1978. Furthermore, the 90 percent feasibility studies loan program mandated in the Public Utility Regulatory Policies Act of 1978 (supra) was implemented February 19, 1980, with publication of the final rules in the Federal Register.[18]

3. ENVIRONMENTAL READINESS

Conflicts exist between the best use for small hydro (peak load production) and environmental impacts of such use (reservoir fluctuations and downstream surges). Many developers are planning run-of-the-river modes for existing dams to avoid this conflict, but economic pressures may dictate modifications to increase head and/or to design for some peak power capability. The environmental conflicts associated with new site development are well documented.[19] [20] [21] However, it is not established that the environmental consequences of low-head development are as severe as those associated with the construction of large, high-head power dams. Analysis is needed to establish the relative impact of low and high dams (existing and new) and the relative impacts of existing dams and new hydro sites versus other energy supply options. Legislation exempting existing dams where no flow regime changes are proposed could be desirable. The question of fish passage is also an area of major concern. Solutions to this problem could include methods incorporated into the dam structures, such as fish ladders or fish elevators.

4. INSTITUTIONAL STATUS

Current institutional factors which inhibit further development include a lengthy licensing process and reluctance on the part of

[17] Ibid., pp. 59-62, 148-151.

[18] Loans for Small Hydroelectric Power Project Feasibility Studies and Related Licensing: 10 CFR Part 797. Federal Register, v. 45, no. 12, Jan. 17, 1980: 3538-3549.

[19] U.S. Dept. of Energy. Small Scale Low Head Hydro. Environmental Readiness Document. Washington, 1978, 16 p. plus appendixes (DOE/ERD-0009.)

[20] See, generally, Waterpower '79: An International Symposium on the Potential of Small Scale Hydropower. Washington, D.C. Oct. 1-3, 1979. Washington, U.S. Dept. of Energy and U.S. Army Corps of Engineers [proceedings in press].

[21] See, generally, Hydropower: A National Energy Resource. Proceedings of an Engineering Foundation Conference. Easton, Maryland, Mar. 11-16, 1979. New York, Engineering Foundation, 1980, 365 p.

large utilities to bother with the purchase of small-capacity outputs of private or municipal producers. The Federal Energy Regulatory Commission (FERC) has jurisdiction over almost all hydroelectric projects, and numerous Federal and State permits are necessary to receive a FERC license. The FERC has developed a simplified licensing procedure for projects up to 1.5 Mw and is currently engaged in shortening the licensing procedure for projects between 1.5 Mw and 15 Mw. Extramurally, FERC is working with other Federal agencies as well as State agencies to simplify their requirements and accelerate approval procedures for hydro project applications. In addition to the many Federal agencies involved in the permit process, developers may have a long legal maze to get through at the State level, and requirements for compliance in certain States have been characterized as an absolute nightmare. One possible solution to the multiagency tangle may lie in the kind of one-stop shopping program developed in Massachusetts, where the State Energy Office has taken the lead in permitting small hydro projects, with all other agencies required to provide their inputs through that office.[22]

In the matter of utility attitudes, there is a reluctance to connect to small, decentralized supply sources. There are also questions about the rate-base effects of sites developed by private interests. Some resistance is encountered to paying fair market prices for hydropower produced, and sold into the grid, because of the intermittent nature of the power at sites with little or no storage capacity. There is concern about transmission system stability for networks with a large intermittent and decentralized supply component.[23] Studies might be planned to develop justification for placing a higher value on electricity from hydropower. If the electrictiy were used for peaking it would have a higher value, particularly under avoided cost purchasing. Certain of these situations could also be corrected by legislative action through amendments to the Federal Power Act.

5. INFORMATION TRANSFER

It is important for potential developers to understand the technology, economics and incentives for using small-scale hydro. Information transfer concerning state-of-the-art and Federal activities is critical to achieving such understanding. The DOE has sponsored several workshops including an international hydropower conference to promote information transfer and to share the knowledge and experience of U.S., and foreign developers.[24]

III. POTENTIAL OBSTACLES TO R. & D. OR TECHNOLOGY IMPLEMENTATION

A number of regions in the United States would appear blessed with ideal circumstances—both unused dams and adequate water. But this combination does not necessarily make hydropower the answer. There exists considerations of engineering, economic, fi-

[22] Low-Head Hydro Lures $1-Billion Marketr, p. 20.
[23] Mitchell, Allan G. Pricing Electric Power From Small Hydroelectric Plants, p. 1-3.
[24] Waterpower '79. An International Conference on the Potential of Small-Scale Hydropower. Co-sponsored by the U.S. Department of Energy and the U.S. Army Corps of Engineers. Washington, D.C., Oct. 1-3, 1979.

nancial and environmental feasibility; competitive use of water impounded by existing dams; and many institutional and legal problems which could place limits on the amount of hydropower potential to be realized.

A. Technical

1. ENGINEERING CONSIDERATIONS

Factors relevant to this consideration include engineering techniques for designing small power houses and standardized low-head/low flow turbines and generators. The renewed interest in small-dam power is creating a market for new generating equipment that could result in $1 billion worth of projects in the near term.[25] Until recently, the small "bulb" turbines whose compact bulb-shaped housing makes them ideal for small-dam powerhouse installations, were not manufactured in the United States. In a bulb turbine/generator, the bulb-encased generator is placed underwater with the turbine, eliminating the expense of separate generator housings. The reason for the low level of U.S. design and manufacturing activity was the lack of interest in and demand for small-scale hydropower prior to recent fossil fuel price increases. Now several U.S. companies are tooling up to produce bulb turbines.[26]

2. RESOURCE AVAILABILITY

The capacity available from run-of-the-river hydroelectric plants will vary throughout the year. Typically, water flow rates reach a maximum during the spring run-off and a minimum either during the heat of summer or when the surface water is frozen and cannot flow. Unfortunately, the times of peak demand for electrical energy occur during the summer (air conditioning load) or the winter (lighting and heating load). A run-of-the-river plant having no pondage might be unavailable to a utility due to low water conditions during the utility's peak demand season. Therefore, if the electric utility cannot rely on the capacity during the period of peak demand, fossil-fueled capacity will be required, in addition to the hydro units, to meet the peak demand. This consideration could reduce the value of run-of-the-river plants to a utility.

If the hydro plant is owned by a private corporation rather than a utility, the private owner reaps all the benefits of low cost power when the water flow is available but must turn to the utility for back-up power when the water flow is unavailable. The utility gets none of the benefits of the hydro plant but may still need to install fossil-fueled capacity to meet the power demand of the hydro plant owner during the season of minimum water flow. If this season coincides with the utility's peak demand season, the cost impact on the utility and indirectly on the customers of the utility could be important. One method for dealing with seasonal variability of the

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[25] Low-Head Hydro Lures $1-Billion Market, p. 20.

[26] The Allis Chalmers Corp. of Milwaukee, The Nation's largest producer of turbines, has developed a line of new turbines specifically suited for generation power at small dam sites (up to 50-foot heads and up to 5 Mw capacity), and an engineering subsidiary of Morrison-Knudsen Company is participating with the Government in the installation of bulb turbines at three Idaho dam sites. Other companies include: Hydro Energy Systems, Inc., New York, N.Y.; General Electric Co., Schenectady, N.Y.; TAMS, New York, N.Y.; Tampella USA, Inc., New York, N.Y.; Worthington Pump, Inc., Mountainside, N.J.; Bofors-Nohob, Inc., New York, N.Y.; the James Leffel and Co., Springfield, Ohio; Chas. T. Main, Inc., Boston, Mass.

water flow to run-of-the-river plants is to control the river, with perhaps a single dam upstream creating an associated reservoir.[27]

3. REHABILITATION CONSTRAINTS

Many of the dams included as potential power producers are old and may be in need of extensive rehabilitation. Nearly two-thirds of the dams in New England, for instance, were built before 1931. Reservoir storage capacity is also a function of the age of a dam, where high siltation rates may alter effective storage capacity and regulation capability.

4. NETWORK TECHNOLOGY CONSIDERATIONS

It is difficult for a utility engineer to design power plants and power transmission systems capable of meeting demand for electricity if a substantial part of the capacity is subject to the vagaries of nature. High speed computers and complex system interties are essential in matching demand with supply, but even in a system dominated by large steam electric plants where fuel inputs can be completely controlled, occasional shortfalls occur and may be difficult to adjust for. One of the postulated advantages of distributed energy systems is the location of the energy source close to the energy demand, which reduces transmission losses and costs and increases flexibility in the system's operations. Yet network considerations are absolutely essential because there is no guarantee that hydro sites, run-of-the-river or otherwise, will be available in the vicinity of energy demand, and operating a series of dams as a system to level the load and increase the potential of each individual dam may be necessary.[28]

B. Economic

The cost factor in small-scale hydropower is complicated by the fact that each site has unique streamflow and construction cost characteristics, i.e., the economics are highly site specific. Estimates of the per kilowatt cost of small-scale hydroelectric generation range from $700 to $2,600 per kilowatt of installed capacity, with a median range of $1,200 to $2,000 per kilowatt and energy costs running in the neighborhood of 30 mills per kilowatt-hour.[29]

Proponents of small dams maintain that they represent an economical alternative to oil as a fuel for generating electricity, and generalizations are possible with respect to the relative economic and resource efficiency for hydropower. In terms of economic efficiency, hydropower has several general inherent advantages over thermal power. The useful life of structures is two to three times longer than thermal plants and equipment, hydropower consumes no fuel (a major cost item of thermal power generation), operation and maintenance costs are lower because powerhouse equipment is

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[27] Run-of-the-River Hydroelectric Power Generation. In Distributed Energy Systems. Draft Final Report Prepared for the U.S. Department of Energy by Arthur D. Little, Inc., p. 5-12, 5-13.

[28] Ibid., p. 5-13.

[29] U.S. Department of Energy. Commercialization Strategy Report for Small-Scale Hydroelectric Power, p. 1-4.

less complex, and hydropower is capable of almost instantaneous response to increased load demands.

Historically, these inherent advantages have been offset by the fact that initial investment costs per unit of capacity have been greater for hydropower than for thermal plants and related equipment. Consequently, the utility industry had contended that large, centralized generating stations provide cheaper electricity than would hundreds of small dams. But this advantage is now being narrowed by the sharp increases in fuel costs and investment costs associated with the siting and construction of fossil fuel and nuclear plants, including acquisition and operating cost increases for air and water pollution control equipment.

The cost of operating plants is often cited as the reason why so many small run-of-the-river hydrogenerators were shut down in the past. Before the equipment became available to control the hydroplants remotely, it was necessary to have plant operators on site 24 hours a day in order to take full advantage of the available water. Thus, it cost about the same amount to operate the smaller plants as to run the larger thermal plants. When the cost of fuels for fossil plants was lower than it is now, the total cost per kwh of operating the larger fossil-fueled plant (including fuel) could be lower than the total cost per kwh of running the small hydro plant. Remote control systems now allow one operator to control several hydro plants from a single location. Thus, the cost of operating a small section is no longer the predominant factor militating against the economic desirability of small hydropower plants.

The traditional advantage of steam-electric power may be narrowed, and perhaps reversed, for hydropower development at *existing* dams, since the capital cost of constructing the dam has already been made. However, in the case of hydropower development at existing dams, the assumption of zero cost for the "fuel" (water) which powers the turbines may not be applicable in all cases, particularly where existing reservoir storage capacity could be currently committed to some productive or socially important purpose.[30 31 32]

C. Environmental

The environmental aspects of hydropower developments can vary significantly from site to site, and each installation should be evaluated independently. The construction of new dams can result in erosion, dust, and other discharges that may contribute to downstream siltation and pollution. Existing dams which have been in place a long time have achieved ecological equilibrium, and the installation of new generating equipment at existing dams avoids most of the impacts associated with construction of a new dam. The best retrofit condition, from an ecological point of view, would involve a simple rerouting of normal reservoir discharge through a turbine. This is identical to a run-of-the-river mode of operation. However, the most economically efficient use of many hydropower dams would be for peak load power, where the reservoir is essentially the hydraulic equivalent of a storage battery which accumu-

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[30] Kassler, Helen S. Power From the Streams. Solar Age, v. 3, July 1978: 17, p. 5–11.

[31] U.S. Department of the Army. Corps of Engineers. Institute for Water Resources. Estimates of National Hydroelectric Power Potential at Existing Dams. A Report Submitted to the President of the United States. Washington, July 20, 1977, p. 14.

[32] A. D. Little, Inc. Run-of-the-River Hydroelectric Power Generation, pp. 5–11.

lates energy most of the time and is rapidly dumped during periods of peak energy demand. Where an existing small dam does not have sufficient storage for peak load operation, it would have to be used in a run-of-the-river mode. But dams with a peak power capability, if converted to such use, would be subject to frequent filling and draw-down of their reservoirs with attendant large variations in downstream flows which might cause environmental, ecological and aesthetic impact. Environmental impacts of small peak load hydropower plants could be highly localized and relatively insignificant, but comprehensive analyses are indicated before the economic and environmental trade-offs of peak power generation can be determined.[33] [34]

D. Social

1. COMPETING USE WITH EXISTING RESERVOIR SPACE

The utilization of hydropower at particular sites may be inconsistent and incompatible with other important water and adjacent land uses. Reservoir space is used to store municipal, industrial, and agricultural water supplies, for navigation, flood control, water quality control, and recreation. Large fluctuations in releases through a dam to meet peak power demands could conflict with recreational objectives, both above and below the dam. Similarly, removing large amounts of water from a river or reservoir for irrigation during the dry season at a point upstream from a hydro plant would reduce the dependable stream capacity of the plant during that period of time. Also, reservoir space reserved for flood waters cannot be used during flood season to simultaneously store water for hydropower, and water rights, like mineral rights, are bought and sold. The water at potential hydropower sites may now be owned by institutions which may expect to use the water for purposes which would eliminate the power generating potential at downstream sites. Furthermore, since a reservoir may be associated with a hydropower project with attendant flooding of lands behind the dam, land use conflicts and trade-offs may have to be taken into account. On the other hand, some uses are not competitive, as in the case of reservoir releases for downstream water quality control which can be passed through a turbine without loss of function.[35] [36]

E. Political

The vast majority of existing small dams are owned by State and local governments, by public and private utilities, by industries and private corporations, and by individuals. The current owners may be using the dams for purposes that would be incompatible with hydropower generation. There are lengthy license and permit procedures to follow, time-consuming environmental impact statements to be prepared, and, in some jurisdictions, complicated water rights and utility rate tax structures to be dealt with.

The Federal Energy Regulatory Commission has amended its rules to simplify application procedures for hydroelectric power

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[33] U.S. Department of the Army. Corps of Engineers. Institute for Water Resources. Estimate of National Hydroelectric Power Potential at Existing Dams, p. 16.

[34] A. D. Little, Inc. Run-of-the-River Hydroelectric Power Generation, p. 5-15.

[35] Ibid.

[36] U.S. Department of the Army. Corps of Engineers. Institute for Water Resources. Estimate of National Hydroelectric Power Potential at Existing Dams, pp. 14, 15.

project preliminary permits and licenses for projects which have generating capacities of 1.5 Mw or less, a dam no more than 25 feet high, and a reservoir with a surface area no larger than ten acres. The new rules established a short form license for these minor water projects and a new application form with accompanying instructions. This rule-making, and two subsequent rule-making procedures—one applicable to projects which have a capacity greater than 1.5 Mw and where a dam and reservoir already exist, and the other applicable to major projects involving new dams and reservoirs—will complete the FERC reform program. The Commission issued a notice of proposed rule making on April 19, 1979, related to hydro projects which utilize existing dams and reservoirs. A final rule in that proceeding was published in December 1979. Proposed regulations relating to major new (unconstructed) projects are anticipated.[37]

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

In a prospectus for small-scale hydropower, DOE stated that its goal was to bring outline up to 1,000 Mw of additional low-head capacity by 1985 and, hopefully, to encourage development of 20,000 Mw by the year 2000. Realistically, the Department expects its loan programs in low-head hydropower to result in completed projects amounting to 300 Mw of additional online capacity by 1985, taking into account study, licensing, and construction time. It is assumed that these completed projects might generate, through a halo effect, at least 300 Mw at existing dams redeveloped independent of Government incentive programs. This raises the added 1985 online capacity to in excess of 600 Mw.[38]

B. Contribution by 2000 or Beyond

DOE estimates that small hydro's market penetration may achieve almost six billion kwh in 1985, about 30 billion kwh in 1990, and about 90 billion kwh in 2000. Assuming a 55 percent capacity factor, this electricity generation would correspond to the following installed capacities: 1,200 Mw in 1985, 6,000 Mw in 1990, and 18,900 in 2000.[39]

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[37] Federal Energy Regulatory Commission. FERC Approves Simplified Application Procedures for Hydro Project Preliminary Permits, Licenses. News Release. Oct. 18, 1979, 1 p. (FE–732).

[38] U.S. Congress. House. Committee on Appropriations. Subcommittee on Energy and Water Development. Energy and Water Development Appropriations for 1980. Hearings 96th Congress, 1st session. Part 6, Department of Energy. Washington, U.S. Govt. Print. Off., 1979, pp. 1068, 1193, 1196.

[39] U.S. Department of Energy. Commercialization Strategy Report for Small-Scale Hydroelectric Power, pp. 4–6.

OCEAN THERMAL ENERGY CONVERSION*

I. Survey of the Current Situation

The ocean environment offers unique sources of energy, holding out promise for augmenting conventional energy sources and for reducing dependence on imported fuels. In this regard, interest has turned to an investigation of the renewable energy resource potential of the world ocean and the significance of the role it could play in adding a useful increment to U.S. energy requirements. Among the sources of renewable energy from the ocean are the temperature differences that exist between warm surface water and cold deep ocean water.

A. Description of the Technology

In 1881, French physicist Arsene D'Arsonval noted that a heat engine could be built to operate on the temperature differences between surface and deep ocean water. Credit also belongs to the American engineer Campbell who proposed the utilization of ocean thermal energy to produce power, employing a liquified gas (e.g., ammonia, carbon dioxide, methyl chloride) as an intermediate working fluid.[1]

Thermal-to-electrical energy conversion in the ocean can be accomplished in two ways. First, sea water can be used as a "working fluid" in a method known as the "open cycle" whereby warm surface water is flash evaporated under a partial vacuum. The steam thus produced passes through and propels a turbine, and is later cooled in a condenser using cold sea water pumped up from the depths. The French engineer, Georges Claude, conducted experiments using this scheme in the early 1930s at a land-based test facility constructed on the coast of Matanzas Bay, Cuba, followed by an unsuccessful demonstration of a floating plant concept on board a converted cargo ship sited in deep water off the coast of Brazil. Variations of the open cycle, known as "lift cycles," are also being studied.

While Claude's open cycle process continues to receive study because of its inherent simplicity and avoidance of possible ecological problems resulting from use of other working fluids, a second method—known as the "closed conversion cycle"—is preferred by contemporary workers because it is believed to present the best solution on the basis of thermal performance, technical risk, availability of essentially off-the-shelf components, and the highest probability of early commercialization. Here, a secondary working fluid, such as ammonia, propane, or Freon-type refrigerant is vaporized and recondensed in a closed loop to drive a turbine. Warm sea water is drawn from the ocean surface and pumped through heat exchangers wherein the secondary working fluid is vaporized; the working fluid then expands and emerges as a high pressure vapor to drive the turbine. From the turbine, exhaust vapor flows to a

*Prepared by John R. Justus, specialist in earth sciences.

[1] See: Engineering News, Aug. 7, 1913.

condenser where it returns to the liquid phase as it is cooled by cold sea water.

B. Known Resources and Reserves

The ocean thermal energy resource base is estimated to be of the order of 10^8–10^{10} (100 million to 10 billion) megawatts (Mw). Environmental consequences relating to a cooling of ocean surface waters could dictate an upper limit on ocean thermal energy conversion (OTEC) at about the 10^7 (10 million) Mw level, with the portion of that power theoretically extractable through an efficiency determined by the Carnot cycle of heat engines at about 10^5 (0.1 million) megawatts electric (Mwe). This represents an upper limit on the potential power capacity of this resource, and certainly only a small percentage of this calculated potential would ever actually be utilized. A detailed account of the range and limitation of the ocean thermal resource base is found in the Congressional Research Service study, Energy From the Ocean.[2] Both coasts of Africa, the tropical west and southeastern coasts of the Americas, and many Caribbean and Pacific islands are situated where adjacent waters possess the year-round thermal characteristics required for operation of an OTEC power cycle. Potential areas of deployment for the United States include: Gulf Stream waters off the U.S. southeast coast, the Gulf of Mexico, Puerto Rico, the Virgin Islands, Hawaii, Guam, Micronesia, and American Samoa.

C. Current Contribution to U.S. Energy Supplies

At present there is no online OTEC generating capacity.

D. State-of-the-Art

Conversion, through an ocean thermal difference machine, of the ocean's thermal energy to electrical energy is not a new concept, but a full-scale ocean thermal power plant has yet to be built and operated successfully over a long period. Schemes for generating power from sea-thermal gradients are, for the most part, based on extant technology and envision either partially submerged ocean-based platforms, high seas plant ships, or stationary nearshore platforms. Several proof-of-concept, baseline designs have emerged involving state-of-the-practice technology employing concepts, materials, and industrial processes currently known to industry. Still other plant concepts are predicated upon innovations in heat exchanger technology, hull design, and plant fabrication.

E. Current Research and Development

1. DOMESTIC

A Federal OTEC development initiative began in 1972, under the auspices of the National Science Foundation's Research Applied to

[2] Justus, John R. Ocean Thermal Energy Conversion. Appears in Energy from the Ocean. Report prepared by the Science Policy Research Division, Congressional Research Service, Library of Congress for the Subcommittee on Advanced Energy Technologies and Energy Conservation Research, Development and Demonstration of the Committee on Science and Technology, U.S. House of Representatives. 95th Congress, 2d session (committee print). April 1978. Washington, U.S. Government Printing Office, 1978, pp. 25–28.

National Needs Program (NSF/RANN), as one of the six solar technologies constituting the original U.S. solar energy research and development effort. Those technologies were selected as being options that could each potentially provide a substantial contribution to the Nation's energy needs by the turn of the century. When the Energy Research and Development Administration (ERDA) was established on January 19, 1975, the lead role in solar energy was transferred from NSF to ERDA. This responsibility now resides with the Cabinet-level U.S. Department of Energy (DOE), established by Public Law 95-91 and officially activated October 1, 1977 (Executive Order 12009). The following table lists OTEC appropriations for fiscal year 1972 through fiscal year 1980.

TABLE 11.—*OTEC appropriations*

Fiscal year:	*Thousands*
1972	$85
1973	230
1974	730
1975	2,955
1976	8,585
1977	13,500
1978	36,000
1979	38,200
1980	43,000

In fiscal year 1981, $39.0 million was appropriated to continue the program.

Although OTEC program management is the prime responsibility of the Department of Energy, it involves other Federal agencies, as well as university and industrial contractors. Both the Department of Commerce and the U.S. Navy are participants. So are the DOE's Argonne, Lawrence Berkeley, and Oak Ridge Laboratories, as well as the DOE's Solar Energy Research Institute.

In the first phase of the development program, small-scale OTEC heat exchanges—up to 1 Mw thermal (approximately 25 kilowatts electric)—were designed and tested to gain an understanding of thermal performance and related biofouling (fouling cuased by growth of marine organisms), cleaning, and corrosion of heat exchanger surfaces. In the second phase, now under way, a T-2 tanker was refitted for deployment in mid calendar year 1980 as a 1-Mwe test facility called OTEC-1. Five candidate heat exchanger designs and other large-scale systems components will be tested at sea and their performance evaluated. In the third phase a pilot plant is planned so that performance and reliability data can be obtained from a complete 10 to 40 Mwe system. Conceptual designs for such a plant have been considered in spar-buoy, ship, and land-based configurations. In addition to providing technical performance data, the pilot plant will allow a more accurate projection of costs for commercial OTEC power plants in the 100 to 400 Mwe range. The primary goal of the pilot plant program is the generation of electricity at a sufficient scale to convince potential users that large commercial OTEC power plants are feasible in U.S. mainland electric applications, or that smaller units (40 to 50 Mwe) represent a competitive alternative for the generation of base-load electricity for U.S. islands.[3] [4]

[3] Cohen, Robert. Energy From Thermal Gradients. Oceanus, v. 22, no. 4, Winter 1979/80: 17.
[4] Rumbaugh, Jeffrey H., et al. Thermal Energy Conversion: Tapping the Sea Depths. IEEE Spectrum, v. 16, August 1979: 42.

2. FOREIGN

French scientists currently have a three-phase program coordinated by the Centre National pour l'Exploitation des Oceans, begun in 1978. The first phase, which ended in 1979, was a $1.8 million feasibility study for a 10-Mwe generating plant. The second phase runs through 1982 and calls for the selection of a specific working system and testing of major components. The suggested budget for this phase is about $5 million. The third phase involves construction of a demonstration plant in 1985 at a projected cost of up to $30 million.

Elsewhere in Europe, most interest centers on the efforts of EUROCEAN, a consortium of 25 industrial companies from 9 countries.[5] In Brussels in February 1979, a EUROCEAN OTEC group was organized and included the following eight member companies: Alfa-Laval, Johnson Group, Kockums and Vattenbyggnadsbyram (Sweden); Banque Europeenne de Credit (Belgium); Hollandsche Beton Group (the Netherlands); Micoperi and Tecoromare (Italy). Funds for development of a 10 Mwe closed cycle plant were requested from the governments of Sweden, the Netherlands, and Italy. Plans call for about $50 million to be spent over a five-year period. A related project calls for a combined aquaculture/OTEC/desalination plant.

Japanese development of OTEC began in 1970 with technical and economic evaluations of the concept. Since 1974, the emphasis has been on a 1.5 Mwe, land-based, experimental station. However, an ocean-sited demonstration plant with an output of 100 Mwe has been under development since 1975. In both cases the working fluid is ammonia, although other working fluids have been proposed. Considerable effort has been expended in their program on heat exchanger design and the identification of thermal and chemical pollution that might result from OTEC operations. The immediate future in Japan's OTEC development calls for the design and testing of a 1.5 Mwe, barge-mounted plant operating with ammonia across a temperature difference of 20 degrees C (36 degrees F). Commercialization is anticipated in the 1990 time frame.[6] [7] [8]

II. PROSPECTS OR REQUIREMENTS FOR FURTHER DEVELOPMENT

A. Research and Development

While proof-of-concept design studies have been completed using state-of-the-art technology, and although OTEC operating principles are well documented, both closed and open cycle systems do pose complex engineering and cost problems. Major analyses and studies conducted in the latter half of the 1970s have formed the basis for a large body of continually evolving research, analysis, and review of OTEC technology and its applications. The total available information and the complexity of the national OTEC research program have changed rapidly with quick progress from paper and laboratory studies to testing of hardware of significant

[5] Belgium, France, Great Britain, Italy, the Netherlands, Norway, Spain, Sweden, and Switzerland.

[6] Notes from Sixth OTEC Conference. Washington, D.C., June 19-22, 1979.

[7] The French program is reviewed in the December 1978 issue of Solar/Ocean Energy Liaison newsletter, the Japanese program in the September 1978 and June 1979 issues, and the EUROCEAN program in the June 1979 issue.

[8] OTEC Projects Promise Electricity by 1990s. Chemical and Engineering News, July 16, 1979: 25-26.

sizes in both land and sea environments. Important test results have been obtained regarding thermal performance of OTEC heat exchangers and related biofouling, cleaning, and corrosion of heat exchanger surfaces. Principal investigators point out that refinement, optimization, and further engineering development are needed in several key areas in order to adapt the technology for economically competitive applications. Major studies are being conducted on power subsystems integration; platform/hull configuration; submarine electrical transmission cables; design, fabrication and deployment of the pipe required for cold water intake; long-term effectivenes of biofouling countermeasures in cleaning heat exchanger surfaces; alternatives to the ammonia vapor closed power cycle; and possible environmental effects of and on OTEC subsystems.[9]

B. Demonstration

Based on engineering development and advanced research and technology activities, major integrated power cycle systems are scheduled for testing on board OTEC-1, an ocean-going engineering test facility, and in OTEC modular experiments. Accumulated test data will be utilized in studies to project cost data for baseline designs of commercial OTEC systems to help determine optimum configurations for OTEC demonstration efforts. The modular experiments will provide for the building and operation of power plants about 10 Mwe in size during the mild 1980s. The results of these modular experiments will be made available to interested utility and industrial-user groups in order to aid the commercialization process.[10]

The first test of an ocean thermal energy conversion cycle began August 2, 1979, off Ke-Ahole Point, Hawaii. A closed ammonia power cycle was employed in Mini-OTEC, an experimental 50 kilowatt electric (kwe) gross power, barge-mounted ocean thermal power plant assembled from off-the-shelf components. The plant—not an optimized system—tested key power system components under ocean conditions, while producing approximately 10 kwe of net power. About 40 kilowatts of the 50-kilowatt capacity went to run the plant's pumps and other operating equipment; the remainder powered test equipment on-board; no energy was transmitted to shore. Three million dollars in funding was shared by the State of Hawaii and a consortium of three corporations, and the plant was operated for the State of Hawaii by the Hawaii Natural Energy Institute, affiliated with the University of Hawaii.[11] [12]

An unsolicited proposal to construct and operate a 40-Mwe OTEC pilot plant ship was submitted to the DOE by a group of ammonia producers in conjunction with a number of agrochemical companies and a major U.S. shipyard.. Plans for the construction of a high seas OTEC plant ship, which would produce onboard about 125 tons of ammonia per day, were summarized in testimony before the House Subcommittee on Oceanography and the Senate Subcommit-

[9] Office of Solar, Geothermal, Electric, and Storage Systems. Ocean Systems Program Summary. Washington, U.S. Department of Energy, 1979, pp. 7-24. (DOE/ET-0083).

[10] Ibid., pp. 7-8.

[11] White, Hank. Mini-OTEC: She Runs. Ocean Industry v. 14, no. 11, November 1979: 78-82.

[12] The three corporations are Lockheed Missiles and Space Company, Dillingham Corporation (A major Hawaii-based engineering and construction firm), and Alfa-Laval (a heat exchanger manufacturer).

tee on Energy Research and Development.[13] Details concerning submittal to DOE of an unsolicited Utility Site Support proposal for an OTEC demonstration facility also were outlined at these hearings.[14]

C. Commercialization

The stated objective of the U.S. OTEC development program is to demonstrate to industries and utilities the technical performance, reliability, and cost-effectiveness of OTEC systems in order to add a useful increment to U.S. energy supplies. The achievement of this goal requires both a favorable economic environment as well as the refinement of the technology. Many advocates believe that when the technology is made cost competitive, market forces will ensure that a substantial supply will develop naturally. Consequently, there is a preoccupation with cost comparisons—capital costs ($/kw) and unit energy costs (mills/kwh). Current appraisals have tended to suggest that this is an oversimplification which disregards other economic variables such as lead time, domestic and international policy decisions, the availability of resources, and other realities of the market decision-making process.[15] Until operational experience is obtained and economic performance can be verified through large-scale commercial demonstrations of OTEC technology, investment uncertainty will continue to exist. Assuming that the Federal Government does not intend to own and operate OTEC systems directly, the critical factor is whether the private and public sectors will raise the necessary capital and undertake the construction and operation of OTEC plants. In advance of economic competitiveness, a suitable economic environment might be created or artificially stimulated. If investment opportunity were not adequate, then a package of stimulating incentives might be considered, such as a combination of loan guarantees, low-interest loans, investment tax credits, and cost-sharing arrangements.[16]

Many factors are involved in OTEC commercialization beyond questions of technical and economic viability. Financing of OTEC plants must be obtained: it is yet to be determined who will be the

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[13] Under the leadership of Devco International, Inc. of Tulsa, Oklahoma, elements of the ammonia industry formed the Solar Ammonia Co., SOLARAMCO, to make the offer to DOE, in conjunction with Pullman Kellogg Co. and Avondale Shipyards. However, the DOE declined the offer.

[14] The proposal for construction and operation of a demonstration facility in partnership with DOE was submitted by Puerto Rico and contains a detailed plan for both Federal government and utility (Puerto Rico Water Resources Authority and OTEC Utility Users Council) participation. The government of Hawaii has also made an offer to DOE to share costs in the development of an OTEC pilot plant. Senate hearings were held Oct. 15, 1979; see U.S. Congress. Senate. Committee on Energy and Natural Resources. Subcommittee on Energy Research and Development. Ocean Thermal Energy Conversion Research, Development, and Demonstration Act. Hearing, 96th Congress, 1st Session, on S. 1830. Washington, U.S. Govt. Print. Off., 1980, 121 p. House hearings held Jun. 21, Sept. 20, 1979; Jan. 30, 31, and Feb. 27, 1980; see U.S. Congress. House. Committee on Merchant Marine and Fisheries. Subcommittee on Oceanography and Subcommittee on Merchant Marine. Ocean Thermal Energy Conversion. Hearings, 96th Congress, on OTEC Oversight and on Ocean Thermal Energy Conversion Act of 1980—H.R. 6154. Washington, U.S. Government Printing Office, 1980, 495 p.

[15] Naef, Frederick E. Economic Aspects of Ocean Thermal Energy Conversion. In Proceedings of Joint Conference on Sharing the Sun, Solar Technology in the Seventies. K. E. Boer, editor. American Section, International Solar Energy Society and Solar Energy Society of Canada, Inc. Winnipeg, Aug. 15–20, 1976. Vol. 5, Solar Thermal and Ocean Thermal. Cape Canaveral, Florida, American Section of the International Solar Energy Society, 1976. Pp. 393–411.

[16] Title II section 221 of the Crude Oil Windfall Profit Tax Act of 1980 (Public Law 96–223) provides a 15 percent nonrefundable business energy investment tax credit for equipment used to convert ocean thermal energy into electrical energy or another form of usable energy. The credit is allowed through Dec. 31, 1985, for qualifying equipment at two locations to be designated by the Secretary of the Treasury after consultation with the Secretary of Energy.

owners or operators. Candidates include consortia of industries, utilities, and shipowners; leverage-lease financing is another possibility. Thus centralized OTEC facilities might be subject to decentralized control.

Operation of OTEC power plants and ships in the Economic Zones [17] of coastal nations and in international waters may require bilateral and multilateral agreements among nations. Along with Government incentives, there may be a need to avoid regulatory features that might discourage financial investments. The relative attractiveness of OTEC as an investment opportunity, in an era when the demand for capital might exceed its supply, may be a strong factor in determining market penetration, perhaps outweighing questions of cost-competitiveness. Under the auspices of the Federal OTEC Program, investigations are proceeding on the legal, policy, technical, and financial incentives or proper combination thereof that may be required to create or artificially stimulate a suitable economic environment for investment in, and construction of, OTEC power plants.

Studies have been initiated on technical integration of OTEC-derived electricity into electric energy networks by examining the planning and scheduling operations of electric utility systems. Until these issues are identified and settled, reliable estimates of the value of OTEC are difficult to make. In order to identify specifications for planning and scheduling operations of electric utility systems, present planning tools and philosophies of electric utilities will be tested against available OTEC baseline concepts. Analyses are underway of OTEC applications and market potential for OTEC products other than electricity. Although the electricity-to-shore-via-cable option appears to be the OTEC application nearest to being commercially competitive, it has been proposed that the power generated be used on-site for energy intensive refining and manufacturing processes on OTEC plant ships or at ocean energy industrial complexes (OEIC's) when, at considerable distance from land, the transmission of electrical energy via underwater cable becomes prohibitively expensive. Provided the electricity is cheap enough to make a process economically feasible, the on-site production of chemicals, the synthesis of methanol, and the generation of hydrogen may have promising market potential. Also associated with ocean thermal systems are the possible options of producing food through mariculture, providing fresh water, and extracting ocean minerals.[18]

III. Potential Obstacles to R. & D. or Technology Implementation

A. Technical

Both closed and open-cycle OTEC systems hold promise for commercial applications, However, researchers in the United States regard the state of development of open-cycle technology as being less advanced (by several years) than closed-cycle technology. Be-

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[17] The Economic Zone, or Exclusive Economic Zone (EEZ) as it is frequently called, is an area in which a coastal state has the exclusive right to explore and exploit the ocean resources lying off its coast between 12 and 200 nautical miles.

[18] Cohen, Robert. Energy From Ocean Thermal Gradients, pp. 17, 18, 21.

cause of the need in the open cycle to harness the energy in low-pressure steam, extremely large turbines must be utilized, and degasifiers must be employed to remove dissolved gases from the sea water. Recent open-cycle studies are encouraging, however, and point to cost-effective solutions to turbine and degasification problems.[19]

Closed-cycle power systems and their associated heat exchangers present several technical and cost challenges. The exchangers must transfer heat cost-effectively, and there must be a viable way to protect them against corrosion and biofouling layers, both of which inhibit heat transfer. Extensive at-sea testing near Hawaii and in the Gulf of Mexico has been underway for several years to establish biofouling rates and countermeasures. Chemical, mechanical, and sonic techniques can be used for cleaning the sea-water side of heat exchanger surfaces. The technical viability and cost of the heat exchangers are key factors, since they can represent up to half the total plant investment.

Other OTEC subsystems present technical problems that also must be solved at reasonable cost. In particular, viable solutions are being sought for designing and deploying OTEC cold water pipes and submarine cables. Candidate cold water pipe materials include fiberglass-reinforced plastic, elastomers, and lightweight concrete. Pipe lengths of about 1,000 meters will be required, with diameters of about 10 meters for a 40-Mwe power output. Submarine power cables rated at 100 Mwe or greater, including bottom and riser cables, will need to be designed to withstand unprecedented electrical and mechanical stresses.

Various platform configurations have been considered for commercial OTEC power plants, including ship, submersible, and land-based designs, Possible impacts of the environment on plant design and operation and, where submarine cables are employed, sea-floor conditions between the plant and the shore need to be taken into account. The ability to withstand severe weather conditions, for example, may necessitate the use of a submarine design.[20] [21]

B. Economic

Like most solar technologies, OTEC is capital-intensive, and the capital cost of commercial OTEC power plants may be a crucial factor in determining how competitive this source of energy will be in relation to other options. Based on available estimates, a reasonable target capital cost for the eighth OTEC production unit in the 100 to 400 Mwe size range is projected to be about $2,600 per kilowatt. However, costs may well exceed the target by up to 40 percent or may be lower by 20 percent. This estimate applies to the

[19] See, generally, the papers in Session No. 9—Open-Cycle OTEC Power Systems and OTEC Cycle Innovations. Appearing in Ocean Thermal Energy for the '80s. Proceedings of the Sixth Ocean Thermal Energy Conversion Conference. Washington, D.C., June 19-22, 1979. Laurel, Applied Physics Laboratory/Johns Hopkins University and Washington, U.S. Department of Energy, 1980, v. 1, p. 9.1-9.11. (Conf-790631.)

[20] Cohen, Robert. Energy From Thermal Gradients, pp. 15-17.

[21] Justus, John R. Ocean Thermal Energy Conversion. In Energy from the Ocean. Report Prepared by the Science Policy Research Division, Congressional Research Service for the Subcommittee on Advanced Energy Technologies and Energy Conservation Research, Development and Demonstration. Committee on Science and Technology, U.S. House of Representatives. 95th Congress, 2d session (committee print). April 1978. Washington, U.S. Government Printing Office, 1978, pp.45-66.

electricity-to-shore option, including the cost of a submarine cable system, for a plant located 140 nautical miles west of Tampa, Florida. Realistic estimates of capital costs vary from $2,400 to $4,000 per kilowatt of installed capacity. These capital costs lead to unsubsidized energy costs exceeding 70 mills (7 cents) per kilowatt-hour of electricity if capacity factors, interest during construction, installation costs, and other financial assumptions are properly accounted for. Since OTEC plants do not require fuel for plant operation, a major cost component is for amortization of the capital investment. These estimated cost ranges are comparable to costs projected for other baseload power sources in the Gulf Coast electrical market for the years 1990 to 2000.[22] [23]

Since the first OTEC power plants may be more expensive than later units, energy costs may be correspondingly higher initially. Even so, at island locations, such as Puerto Rico and Hawaii, where most of the electricity generated is derived from the combustion of oil, favorable electricity markets might exist for the first OTEC plants. The capital costs for OTEC plants at such locations could be less than those for plants off Gulf Coast States, both because the ocean thermal resource is somewhat better at these locations and the power cables would need to extend only several miles from shore. Accordingly, OTEC investigators have estimated that even the first OTEC commercial plants might be competitive in the 1990's versus an oil-fired alternative at island locations.

It is important to recognize that the foregoing estimates of OTEC economics remain speculative and uncertain because a commercial demonstration OTEC power plant has not as yet been built and because of the degree of as yet unpredictable escalation of OTEC plant cost estimates. However, based on the analyses and research performed to date, results of which were reported at the DOE-sponsored sixth and seventh national OTEC conferences,[24] [25] a consensus exists among the various OTEC investigators that engineering feasibility is assured and that a true economic break-even point may possibly occur in the early 1990s in island electric applications.

C. Environmental

Exploitation of the ocean's thermal energy involves the extraction of heat from the ocean through the circulation and redistribution of large quantities of warm ocean water from near the surface and cold ocean water from the deep. Local and widespread implementation of this technology might impact the oceanic environment and its surroundings by modifying the thermal, biological, physical, and chemical properties of that environment. Thermal perturbations might affect the optimum performance of the plant. For example, water exhausted from the evaporators or condensers, if recirculated through the warm water intake, could reduce the plant's net power output. Also, a reduction in ocean surface temperature might alter local climatic conditions, but appropriately directed discharge of the heat exchanger effluents could limit sur-

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[22] Cohen, Robert. Energy From Ocean Thermal Grandients, p. 17.

[23] Clorfeine, A.S. et al. DOE's In-House Assessment of OTEC: Summary of Principal Findings, OTEC Cost and Efficiency. The OTEC Liaison, v. 2, no. 11, November 1978: 1, 3—7.

[24] Ocean Thermal Energy for the '80s. Proceedings of the Sixth OTEC Conference. Washington, D.C., June 19-22, 1979. Laurel, Applied Physics Laboratory/Johns Hopkins University and Washington, U.S. Department of Energy, 1980. 2 volumes (various pages) (Conf.-790631.)

[25] Seventh Ocean Energy Conference. Expanded Abstracts. Washington, D.C., June 2-5, 1980. Arlington, Gibbs & Cox, Inc. and Washington, U.S. Department of Energy, 1980, 1 volume (various pagings).

face temperature decreases to a small fraction of a degree Celsius. Other possible consequences of OTEC power plant operation to be addressed include the impingement and entrainment of biota; possible discharges of biocides, corrosion products, and working fluids; artifical reef, nesting, and migration impacts; and worker safety. Research projects for investigating these concerns are summarized in a DOE environmental development plan for OTEC.[26] Impacts of environmental parameters on the design, siting, and operation of OTEC plants are also to be considered and include the effects of winds, waves, and surface/subsurface currents on the power plant platform, and riser and bottom transmission cables. For instance, the quality of the thermal resource could be degraded by oceanic mixing associated with such natural phenomena such as coastal upwellings and hurricanes. Moreover, OTEC power plants must be designed to structurally withstand heavy seas. A knowledge base in this regard has been established by the offshore construction industry in the design and building of structures for operations in the harsh environment of the North Sea oil fields.

D. Social

Secondary impacts associated with site selection, construction, and operations of an OTEC facility may also affect existing societal and institutional structures. New jobs would be created and shore-based "boomtown" growth might occur, with its associated impacts on housing, education, and sanitation. However, fabrication sites and techniques already are available in coastal shipbuilding communities. Protected deep water areas near deployment sites will be required for final assembly of modular plants, resulting in logistical transportation and support impacts typical for any deep-water construction project.

The use and/or production of chemicals or energy intensive products (e.g., ammonia as a working fluid, chlorine as a biocide, liquid hydrogen or ammonia as a product) and the possibility of collision with ocean going vessels could endanger the safety of operations and maintenance personnel. Worker safety concerns are regulated by the Occupational Safety and Health Administration and, for strictly marine occupational safety, by the U.S. Coast Guard. Worker-safety programs typically associated with construction and operation of large-scale projects might be implemented in accordance with the products or chemicals intended to be used or produced at the plant. Ocean traffic patterns might also be studied to determine the likelihood of collisions occurring at site designations.[27]

The construction and operation of OTEC vessels might provide social/economic benefits by generating new U.S. tax revenues, revitalizing the U.S. shipbuilding industry, and creating jobs in core city areas where many large U.S. shipyards are located. The current world shipping recession has reduced merchant ship construction opportunities, and the U.S. shipbuilding industry faces a crisis

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[26] U.S. Department of Energy. Office of Assistant Secretary for Energy Technology and Office of Assistant Secretary for Environment. Environmental Development Plan, Ocean Thermal Energy Conversion. Washington, U.S. Government Printing Office, 1979, 48 p. (DOE/EDP-0034.)

[27] Ibid., pp. 4, 24, 25.

situation.[28] The backlog of merchant shipbuilding contracts placed earlier in the 1970s is rapidly diminishing. Of 69 merchant vessels now on order in U.S. shipyards, only 22 will remain for delivery after 1980. Consequently, the shipyard resources of the United States may not be fully utilized.

In all, more than 60,000 workers in U.S. shipyards currently face the prospect of unemployment, much of which will apply to minority workers in areas of chronic unemployment. With a multiplier effect factored in, nearly 200,000 workers in equally important supporting industries could be affected.[29] Attendantly, in an analysis prepared for the U.S. Maritime Administration of effects in economic areas other than the power market, the Johns Hopkins/Applied Physics Laboratory estimated that the deployment of 21 commercial-size (300 to 500 Mwe) OTEC ammonia plant ships[30] could create 100,000 new jobs in U.S. shipyards and additional jobs in the aluminum industry, in concrete, in steel, and in the industrial equipment sector of the economy.[31] OTEC construction programs could be supported by such shipyards as those at Quincy, Massachusetts; Norfolk, Virginia; New Orleans, Louisiana; and indeed by at least half a dozen large shipyards around the United States. Furthermore, new jobs would be created in the U.S. flag shipping industry through requirements to crew OTEC plants at sea.[32] However, the level of effort envisioned for a large-scale OTEC construction program may warrant careful accounting of skilled manpower available now and in the future to shipyards and their support industries and to the seafaring and shoreside components of the U.S. merchant marine.

E. Political

The development of technology for ocean thermal energy conversion, is proceeding at a time when the law governing use of the world ocean is in flux, and issues of ocean rights and responsibilities may arise beyond those treated by conventional maritime law and treaties. It is possible that OTEC development may open up a new area of international interest in the ownership and operation of ocean-based energy-producing facilities.

The status of a cable-connected OTEC plant operating on the territorial or high seas warrants clear definition. Some experts define it as a moored ship, but others maintain that the permanent connection to shore makes it an artificial island. This ambiguity in turn raises questions relating to technical design, insurance, royalties, and other economically oriented issues. This becomes less of a

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[28] Statement of Edwin M. Hood, President, Shipbuilders Council of Amerca. Appears in: U.S. Congress. Senate. Committee on Energy and Natural Resources. Subcommittee on Energy Research and Development. Ocean Thermal Energy Conversion Research, Development, and Demonstration Act. Hearing, 96th Congress, 1st Session, on S. 1830. Oct. 15, 1979. Washington, U.S. Government Printing Office, 1980, pp. 104-105.

[29] Ibid.

[30] Ammonia is a vital commodity in the manufacture of fertilizers, and over 95 percent of U.S. ammonia production uses natural gas in the production of ammonia.

[31] Avery, W. H. et al. Maritime and Construction Aspects of Ocean Thermal Energy Conversion Plant Ships. Laurel, Maryland, Johns Hopkins University/Applied Physics Laboratory, 1976, v. 1A, p. 4, and v. 1B, pp. 1-8 and 1-9.

[32] Statement of E. J. Francis, Applied Physics Laboratory, Johns Hopkins University. Appears in: U.S. Congress. House. Committee on Merchant Marine and Fisheries. Subcommittee on Oceanography and Subcommittee on Merchant Marine. Ocean Thermal Energy Conversion Act of 1980. Hearings, 96th Congress, 2d Session, on H.R. 6154. Jan. 30, 31; Feb. 27, 1980. Washington, U.S. Government Printing Office, 1980, p. 310.

problem with untethered OTEC plant ships which are clearly vessels because they can maneuver and/or drift. Siting an OTEC plant within the territorial waters of one nation may not necessarily avoid international legal problems if possible downstream impacts of OTEC operations are experienced.

Another fundamental legal question requiring resolution is the applicability of Federal and State regulatory law regarding the construction and operation of OTEC power plants. These Federal-State issues include exclusive or joint licensure authority; predominant roles regarding regulation of the OTEC facility; Federal agency jurisdiction (lead agency); and State jurisdiction (project review, assessment of on-shore impacts of construction, operating, servicing, and receiving power and potential products from OTEC plants). These same investigations may be extended to encompass the problem of what international regulatory authority concerning OTEC plants exists now, or is likely to be developed or modified in the context of on-going United Nations Law of the Sea negotiations. A recurring question is whether OTEC would best be assimiliated for purposes of legal responsibility and liability into the body of maritime admiralty law or whether some format for extending "land law" would be a better solution or, perhaps, some new combination thereof.[33] Multilateral agreements or treaties among concerned parties (as is done for fishing rights) and domestic legislation may be necessary to resolve these potential legal problems.[34]

Legislation (H.R. 6154 and S. 2492) was introduced in the 96th Congress in an effort to resolve some of these legal problems. The bills provide for one-stop Federal licensing of OTEC facilities and plantships by the National Oceanic and Atmospheric Administration. Further, by treating facilities and plantships as vessels, they allow owners of OTEC facilities to use the capital construction tax treatment now available to vessel owners under the Merchant Marine Act of 1936 and extent to commercial and demonstration OTEC facilities eligibility for Federal loan guarantees under Title XI of the Merchant Marine Act of 1936.[35] The House and Senate also passed H.R. 7474, calling for the demonstration of OTEC electrical or energy product equivalent capacity of 100 Mwe by the year 1986, 500 Mwe by the year 1989, and 10,000 Mwe by 1999. The bill directs the Department of Energy to prepare a comprehensive program plan and a commercialization plan that would permit realization of these goals. A Technical Panel of the Energy Research Advisory Board is established to assess and evaluate implementation of the programs mandated by the bill.[36]

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[33] Legal, Political, and Institutional Aspects of Ocean Thermal Energy Conversion. Workshop Proceedings. Washington, D.C. Jan. 15–16, 1976. Washington, American Society of International Law, 1977, v. 1 (loose-leaf).

[34] Nordquist, Myron H. and Geoffrey S. Yarema. Generating Energy on the High Seas: Laws Needed to Protect Development of Sea Power. The National Law Journal, Nov. 26, 1979.

[35] Hearings were held on Jan. 30, 31, and Feb. 27, 1980 by the House Merchant Marine and Fisheries Subcommittee on Merchant Marine and on Oceanography, and on May 1, 1980 by the Senate Committee on Commerce, Science, and Transportation. See also H. Rept. 96–994 on H.R. 6154 and S. Rept. 96–721 on S. 2492. Senate passed S. 2492 on July 2, 1980. House passed the measure July 21, clearing it for the President. Enacted Aug. 3, 1980, P.L. 96–320.

[36] Hearings were held by the Senate Committee on Energy and Natural Resources (on S. 1830) on Oct. 15, 1979; reported to Senate Dec. 14, 1979, S. Rept. 96–501; passed Senate Jan. 25, 1980; reported to House June 13, 1980, H. Rept. 96–1092; passed House Jun. 17, 1980; passed Senate Jun. 28, 1980. Final action in the House Jul. 2, 1980; final action in the Senate July 2, 1980. President Carter signed H.R. 7474 on July 17, 1980, Public Law 96–310.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

It is not anticipated that OTEC will make any significant contribution to U.S. energy supplies by 1990.

B. Contribution by 2000 or Beyond

Initial projections of estimated OTEC power market penetration appear now to have been somewhat optimistic. For example, the 1974 Federal Energy Administration report, Project Independence, called for the achievement by the year 2000 of 165,000 Mwe, under a "business-as-usual" scenario, or 260,000 Mwe under an "accelerated" scenario. Under the accelerated scenario, OTEC technology was projected to save up to $7x10^{15}$ British thermal units (Btu) of fossil fuel energy per year or 11 million equivalent barrels per day of imported oil by the year 2000. The corresponding values for the business-as-usual scenario in the year 2000 were $1.7x10^{15}$ Btu and 2.7 million equivalent barrels per day of oil that would not need to be imported from foreign sources.[37] In these projections of reduced imports of fuel oil, it is assumed that the particular energy technology (in this case, OTEC) reduces the demand for fossil fules to produce electricity.

In the 1976 report, A National Plan For Energy Research, Development and Demonstration, ERDA projected a total potential power capacity in the year 2000 ranging from 10,000 to 25,000 Mwe. This corresponds to a savings of 0.5 to 1.2 million equivalent barrels per day of oil used in the generation of electricity.[38]

It would seem very optimistic to expect that the technology could achieve the upper bound level of 260,000 Mwe in the year 2000. Even the figure of 25,000 Mwe may be optimistic for that time period in view of the fact that vigorous development plans would have to be undertaken promptly to achieve that capacity. A mix of alternate energy technologies will probably be implemented, which could result in a minute, but perhaps useful, incremental contribution from OTEC to the Nation's power supply approaching 1 to 3 percent by the year 2000.[39]

According to an assessment of OTEC market potential, the DOE observed that entry of OTEC into a U.S. mainland market is unlikely unless or until modular plant concepts and alternate platform designs have been successfully demonstrated, but in any case not before the year 2000.[40] If proved a viable option, OTEC could potentially meet significant percentages of baseload electrical demands in the U.S. Southeast and Gulf Coast region, possibly by the latter half of the 21st century. By 2020, a 20,000-to-40,000 Mwe

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[37] Interagency Task Force on Solar Energy. Project Independence Blueprint. Final Task Force Report. Prepared Under Direction of National Science Foundation. Washington, Federal Energy Administration, November 1974, pp. I-7, I-9, I-25, VI-3.

[38] U.S. Energy Research and Development Administration. A National Plan for Energy Research, Development and Demonstration: Creating Energy Choices for the Future. Washington, U.S. Government Printing Office, 1976, pp. 108-111. (ERDA 76-1)

[39] Richards, W. E. The U.S. Ocean Energy Systems Program. Appears in Ocean Thermal Energy for the '80s. Proceedings of the Sixth Ocean Thermal Energy Conversion Conference. Washington, D.C., June 19-22, 1979. Laurel, Applied Physics Laboratory/Johns Hopkins University and Washington, U.S. Department of Energy, 1980, v. 1., pp. 2.4-1—2.4-7.

[40] Clorfeine, A. S. et al. DOE's In-House Assessment of OTEC: Summary of Principal Findings, OTEC Cost and Efficiency. The OTEC Liaison, v. 2, no. 11, Nov. 1978: 1, 5.

OTEC installed capacity—a small fraction of the required baseload capacity for the Southeast—seems plausible, according to DOE projections. It seems likely, however, that initial commercial implementation for OTEC technology will be in tropical island electric applications of 10 to 100 Mwe replacement capacity. Puerto Rico, U.S. Virgin Islands, Hawaii, and Guam have expressed strong interest in OTEC, and economic, social and political factors appear favorable for the development of island markets at these locations. They have good ocean thermal resources, and the oil-dependent island utilities located there would be competitive markets for early OTEC plants. Conceivably, OTEC could deliver power to U.S. islands in the 1990s, if technical and economic feasibility were proven by the mid 1980s. Based on this assumption, DOE projects a total installed island capacity of 3,000 Mwe by 2000 and 8,500 Mwe by 2020.[41] [42]

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[41] Ibid., pp. 1, 5.

[42] Cohen, Robert and Fred S. Dunning, Jr. An Island Strategy for OTEC Commercialization. Preprint of an invited paper for Solar Energy and Conservation Symposium-Workshop. Miami, Florida, Dec. 11-13, 1978, 6 p. and appendices (revised Apr. 16, 1979).

WIND ENERGY *

I. Survey of the Current Situation

A. Description of the Technology

A wind energy conversion system (WECS) is any machine or device which uses the energy of the wind to produce rotating or oscillating motion, which is mechanical energy. This mechanical energy can be used directly, or can be used to run an electrical generator which changes the mechanical energy to electrical energy. Traditional windmills are the most commonly recognized kinds of WECS, but there are many different forms of wind machines which turn on a horizontal or vertical axis which are being explored in the attempt to harness the wind's energy.

B. Known Resources and Reserves

The kinetic energy available in the wind is virtually limitless. However, an upper global limit of 1.3×10^5 gigawatts has been calculated as the amount of power available to be extracted from the wind.[1] This amount of power is roughly twenty times the worldwide energy consumption rate. For the continental United States, the extractión rate limit has been calculated at 2×10^3 gigawatts or roughly 75 percent of the U.S. total energy consumption.[2] The variability of this resource at any one location means, however, that not all of it can be used to produce electricity.

C. Current Contribution to U.S. Energy Supplies

From the Department of Energy (DOE) program alone, there are almost three megawatts (MW) of WECS capability installed and operating in a utility grid.[3] A number of smaller non-DOE wind systems have been installed throughout the United States for residential and agricultural uses, for example, but at this time there are no commonly accepted figures relating to the total numbers of these machines nor to their cumulative contribution to meeting U.S. energy needs.

To give a perspective on what the DOE installed capacity means, two examples of wind contribution are illustrative. DOE's MOD OA 200-kilowatt machine, installed in Clayton, New Mexico, provides the power for about sixty homes. In that town of about 3,000 people, that is about 15 percent of the power requirements. The DOE MOD 1 machine (2 megawatts) is anticipated to supply power for about 500 homes in the town of Boone, N.C.

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* Prepared by Barbara A. Luxenberg, specialist in aerospace systems technology.

[1] M. R. Gustavson, "Limits to Wind Power Utilization," Science, Apr. 6, 1979: 13.

[2] Ibid.

[3] This total is comprised of four DOE MOD OA 200-kilowatt machines and one DOF MOD 1 2-megawatt machine.

D. State-of-the-Art

Commercialization of wind energy technology does not depend on major technological breakthroughs. However, technical and engineering developments are needed to lower the capital, maintenance, and operating costs of WECS. Technical studies on blades and materials are on-going to determine the most efficient composition and configurations. The large megawatt size WECS, with rotors 100 to 200 feet long are presumed to be the most efficient, and potentially the most productive, WECS but wind machines of this size still need to be verified with actual field testing. The 2 MW, 200-foot diameter DOE machine recently installed in Boone, North Carolina, is the first such field test of a large machine (since the Palmer/Putnam machine in the 1940's) in this country.

A sizable wind turbine industry based on small WECS grew in the United States between 1850 and the 1930's. It died out in the 1930's due to the availability of convenient, low-cost central power through the Rural Electrification Agency. A fledgling small WECS industry is growing now and the machines, though lacking the reliability and longevity of their predecessors,[4] are close to economic viability in remote areas and, with moderate advances, will become viable in a more general market.

E. Current Research and Development

1. FEDERAL R. & D.

The current DOE wind R. & D. program includes developing small (under 100 kilowatt) and large (100 kw and above) wind machines; investigating wind energy applications; evaluating national and local wind resources; and assessing problems and marketing strategies. Current DOE projects include: (*a*) a 100 kw machine in Plumbrook, Ohio; (*b*) 200 kw machines at Clayton, New Mexico; Culebra Island, Puerto Rico; Block Island, Rhode Island; and Kaena Point, Oahu; (*c*) a 2 MW machine at Boone, North Carolina; (*d*) development of a 2.5 to 3 MW system, three machines which are to be installed in the Bonneville Power Administration System near Goldendale, Washington, by 1981; and (*e*) development of two different advanced 4 MW machines by 1984.

The DOE Rocky Flats Plant in Golden, Colorado is testing and developing small wind machines. The DOE's Sandia Laboratories in New Mexico are investigating innovative wind systems. Battelle Pacific Northwest Laboratories is conducting wind characteristics studies, resource assessments, and siting studies for DOE.

The DOE Federal Wind Energy Program is designed to make available reliable, durable, cost-effective WECS as soon as possible, in a range of sizes to meet end uses that have been identified as potential markets for large and small WECS. Specifically, the program has a wind energy cost goal of 1 to 2 cents per kilowatt hour, which DOE believes necessary to make wind power competitive.[5] The program has the goal of erection of 128 large and intermediate

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[4] According to the DOE Commericialization Strategy Report for Small Wind Systems, Draft, TID-28844, 1978, p. 2, small WECS lack the reliability and longevity of their predecessors, probably because of the limited capital and limited engineering and market feedback available to small manufacturers at this early stage. DOE believes that this situation will change shortly.

[5] The national average cost is 3.45¢/kwh.

size WECS (200 kw to 2.5 MW) by 1984, 500 intermediate small machines by 1983, and contribution of the thermal equivalent of 0.01 quads in 1985.[6]

The Department of Interior's Water and Power Resources Service is planning a wind farm (consisting of a number of megawatt size machines) in the Medicine Bow, Wyoming area. The first 4 MW machine for this project has been contracted for. The Department of Agriculture is engaged in R. & D. on the agricultural applications of wind energy. Federal funding for wind energy for fiscal year 1980 amounted to about $63.4 million. The fiscal year 1981 budget request, as passed by the House, amounted to $77.9 million.

2. NON-FEDERAL ACTIVITY

A number of companies in the private sector are interested in WECS, and there are several large scale private projects to commercialize wind power. Southern California Edison Co. has purchased a 3 MW WECS and is installing it in the San Gorgonio Pass near Palm Springs, California. The operation of this machine will supply data to the utility for future decisions on installation of additional wind machines.

The California Water Resources Department is negotiating with a supplier for the purchase of up to 400 million kilowatt hours of electricity per year, which would be generated by 20 horizontal axis WECS totaling about 1 MW capacity. The first of these small machines might be installed in the Pacheco Pass as early as 1980. The State of California plans to generate by 2000 at least 10 percent (30 billion kwh per year) of the State's electricity using wind machines, if the initial machines function well.[7]

Another industrial venture is the array of 100 vertical axis gyro mills built in Dalhart, Texas, and used in connection with a chemical plant which produces bleach. Electricity derived from the WECS is the main input to the process by which sodium hypochlorite is produced.

The Hawaiian Electric Company has agreed to purchase the electricity which may be generated by a planned 80-megawatt wind farm on the island of Oahu. The proposed wind farm would be comprised of 32 2.5 megawatt wind machines. Its planners anticipate it will be fully operational by 1984, though the idea is only in the planning stage and the machines must be procured.

3. INTERNATIONAL

A number of countries are studying the potential of wind energy to help meet their national energy needs. The Canadians have been active in studying vertical axis WECS. The Danes have a number of on-going projects, including one large machine built by students at Tvind. In addition, the Federal Republic of Germany, the United Kingdom, the Netherlands, Norway, Japan, Sweden, and Austria all reported on national wind energy activities at the recent (October 1979) DOE Fourth Biennial Conference and Workshop on Wind

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[6] U.S. Department of Energy. Domestic Policy Review of Solar Energy. Final Report of the Research, Design and Development Panel, October 1978, TID-28837 UC-13, tab J, appendix A, p. 1.

[7] In statement of Dr. James Lerner, California Energy Commission, before the House Committee on Science and Technology, Subcommittee on Energy Development and Applications, hearing on H.R. 3558, Sept. 26, 1979.

Energy Conversion Systems. The national programs which were reported were predominantly in the R. & D. phase.

II. Prospects or Requirements for Further Development

A. Research and Development

1. SMALL WECS R. & D. REQUIREMENTS

According to DOE, small WECS are nearly ready for commercialization now, but "additional R. & D. cycles are needed to reach mass markets." [8] These R. & D. efforts would address key barriers such as utility electrical interfacing, wind load data for design, design for turnkey operations, low maintenance, technical simplicity, durability and high reliability. There are no major technical risks which would question the basic feasibility of small WECS.

As part of its consideration of wind legislation in the 96th Congress, the House Committee on Science and Technology defined what it believes to be an appropriate Federal role in R. & D. for small WECS. The Committee called for a six year (fiscal year 1981–86) accelerated R. & D. applications, testing, and study program costing just under $100 million.[9] This funding would allow one additional generation of each of the various small machine sizes and development of a machine in the 50 to 100 kilowatt range for the agricultural, industrial, and commercial sectors.

2. LARGE WECS R. & D. REQUIREMENTS

There are no major technical feasibility questions with large WECS which need to be resolved by R. & D. However, further development is required to obtain high performance at low cost. Advanced systems should have reduced input loads, high aerodynamic performance, and simpler components and subsystems and should be designed for improved fabrication techniques, higher system optimization, and configuration tradeoff.[10]

The House Committee on Science and Technology called fcr accelerated R. & D. applications, testing and studies for large WECS over a six year period (fiscal year 1981–86) at a cost of just under $200 million.[11] This would allow the parallel development by multiple contractors of the next generation of large WECS.

The DOE believes that the present Federal wind R. & D. program, based on serial development by a single contractor of the next generation of large wind machines, should proceed through fiscal year 1980 and fiscal year 1981 and should concentrate on systems development and tests to achieve initial technical verification.[12] After about 1983, according to DOE, only modest Federal

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[8] DOE, Commercialization Strategy Report for Small Wind Systems, Draft, TID-28844, 1978, p. 18.

[9] U.S. Congress. House. Committee on Science and Technology. Establishment of Wind Energy System Research, Development and Demonstration Program, report to accompany H.R. 5892, 96th Congress, 1st session, Nov. 27, 1979, H. Rept. 96-662, pp. 9-10.

[10] DOE, Commercialization Strategy Report for Large Wind Systems, TID-28843, 1978, p. 2 (Draft.)

[11] H. Rept. 96-662, Establishment of Wind Energy System Research, Development, and Demonstration Program, op. cit., pp. 9-11.

[12] In statement of Dr. Worth Bateman, Deputy Under Secretary of DOE, before the House Committee on Science and Technology, Subcommittee on Energy Development and Applications, at hearings Oct. 17, 1979, pp. 5 and 7.

R. & D. will be needed because the technology and the industry will be at the point at which cost effective use of wind power in windy regions will be practical.[13]

B. Demonstration

Federal demonstrations of WECS are viewed by many energy analysts as essential to achieve industry confidence and rapid commercialization of wind energy systems.[14] Demonstrations should provide an early market in high wind, and/or high potential applications. For small WECS, early demonstrations are seen as a short term necessity to help resolve institutional issues, improve management expertise within the industry, provide growth capital, and allow development of a preparatory sales and service infrastructure. Small WECS can be demonstrated in easily managed cycles at relatively low costs. The DOE recommended a moderate cost-shared demonstration program to provide user experience and market tests, supplemented by incentives, if necessary, to assist economically during early market penetration. Demonstration efforts would eventually be phased out in favor of appropriate incentives.

For large WECS, DOE recommends that cost shared demonstrations should not begin until after February 1981, by which time DOE expects to have completed analyses and acquired test data that indicate that such demonstrations will lead to a viable, self-sustaining industry.[15] Demonstration activities could be implemented in 1982, contingent on the determination by the DOE that WECS are technically, economically, and commercially ready.

Following its consideration of wind energy legislation and requirements, the House Committee on Science and Technology prepared an estimate of wind energy demonstration requirements.[16] For small WECS, the demonstration program would start with $8 million for 250 demonstration units in 1981 and continue until 1986, with 5,000 units at $30 million. Demonstrations would be done on a cost shared basis with DOE providing 50 percent of the capital cost of a system purchased during the first 4 years of the program, a maximum of 35 percent in the fifth year, and 25 percent in the sixth year.

For large WECS, the Committee proposed that the demonstration program start in 1983, with 14 units installed at a Federal cost of $30 million.[17] As with small WECS, the demonstrations would be cost shared and demonstration efforts would increase as R. & D. efforts decreased. By 1988, the number of demonstration units would have increased to 162 and the Federal support to $75 million. In the first six years there would be a maximum cost sharing of 50 percent of the capital cost of a unit; in the seventh and eight years, the Federal input would be a maximum of 25 percent.

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[13] U.S. Congress. House. Committee on Science and Technology. Oversight—Wind Energy Program, hearings before the Subcommittee on Energy Development and Applications, 96th Congress, 1st session, July 30, 1979, p. 56.

[14] For example, see: Going with the Wind, EPRI Journal, March 1980, pp. 16-17; DOE Commercialization Strategy for Large Wind Systems, op. cit., pp. 17-20; DOE Commercialization Strategy for Small Wind Systems, op. cit., pp. 29-30; H. Rept. 96-662, Establishment of Wind Energy Research, Development and Demonstration Program, op. cit., pp. 4-11.

[15] Prepared statement of Worth Bateman, op. cit., p. 4-5, 11.

[16] H. Rept. 96-662, Establishment of Wind Energy Systems Research, Development, and Demonstration Program, op. cit., pp. 9-10.

[17] Ibid.

The ultimate goal of this extensive Federal program in demonstration (and the R. & D. program discussed in A, above) would be to reduce the average cost of electricity produced by WECS at the end of fiscal year 1988 to a level competitive with conventional energy sources, and to reach an installed capacity of 800 megawatts by that time. The Committee suggested that by pursuing this effort over the eight year period, and then stopping Federal support, wind energy should find its market niche through the economics of the marketplace.[18]

C. Commercialization

The following section presents specific data on requirements for wind energy commercialization. It should be remembered that the studies from which this data is drawn are preliminary in nature and that they are based on estimates derived by assigning values to a number of different variables. Changes in values assigned to the variables would thus affect the calculations carried out and the resultant wind commercialization requirements.

1. CAPITAL

Assuming an accelerated commercialization plan for WECS which would enable WECS to supply approximately 7 percent of the U.S. national energy demand by 2000, estimates are that a total investment of $80 to $100 billion would be required.[19] For a market penetration of just under 4 percent, DOE estimates a required capital investment of almost $23 billion by 2000.[20]

Capital costs for production of individual WECS are uncertain at this time because they are based on developmental units, and because a number of variables go into determining costs. The DOE estimates the total installed cost of its Mod 2 2.5 MW WECS at almost $4 million.[21] Mass production of WECS will lower costs, due to the effects of the learning curve, and one estimate of costs for mass production of the MOD 2 would be about $800 per kilowatt and a total installed cost of about $2 million.[22]

2. TIME

The Domestic Policy Review of Solar Energy recommended initiation in fiscal year 1980 of a wind commercialization plan aimed at relatively large-scale production and marketing of wind turbines in several size ranges by about 1984. Commercialization could begin as soon as required characteristics of durability, reliability, and cost effectiveness are achieved.[23]

The proposed DOE cost goal for wind commercialization is to achieve an energy cost of 1 to 2 cents per kilowatt hour by the late 1980's (for both large and small WECS). This cost, along with

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[18] Ibid., p. 8.

[19] DOE. Summary of Current Cost Estimates of Large Wind Energy Systems, study done for DOE by the JBF Scientific Corporation, Washington, D.C. February 1977, DSE/2521-1, pp. 40-41.

[20] DOE Commercialization Strategy Report for Large Wind Systems, op. cit., p. 10.

[21] Ibid., p. 28.

[22] Personal communication with Wind Energy Systems Branch, DOE, January 1980.

[23] U.S. Department of Energy. Domestic Policy Review of Solar Energy, Final Report of the Research, Design, and Development Panel, October 1978, TID-28837, tab J. p. 8.

appropriate incentives, would allow the commercialization of wind energy systems to achieve an energy contribution of around 2 quads by 2000.[24] According to DOE projections, large WECS could be commercialized to the point of penetrating almost 4 percent of the electric utility market by 2000.[25] For small WECS, the first effective market penetration (farm and rural residential market) will probably begin in the early 1980's with significant market penetration in the late 1980's and about 13 percent of the market penetrated by 2000.[26]

Legislation in the House and the Senate during the 96th Congress calls for an extensive research, development, and demonstration program aimed at early commercialization of wind power. House legislation (H.R. 5892) is aimed at reducing the cost of wind power to a level competitive with conventional energy sources by fiscal year 1988, Senate legislation (S. 932) by fiscal year 1986.

3. MANPOWER

One study suggests that 150,000 steady new jobs would be created under a highly accelerated wind commercialization program and a few thousand new jobs if the wind program continues under a business-as-usual scenario.[27] Another study suggests that 40 to 70 workers would be required to operate a 1,000 megawatt wind machine array.[28] A third study notes that manufacture of wind energy conversion systems would not require any new or unusual skills.[29]

4. REQUIRED INDUSTRIAL BASE

The Domestic Policy Review of Solar Energy noted that "wind machines are not so highly specialized a product that the general manufacturing industry will have difficulty entering the field." [30] The industrial sectors which will potentially be involved in commercial WECS production include aerospace companies; current manufacturers of small WECS; manufacturers of large farm and construction machinery; manufacturers of large gears, gear boxes, and bearings; manufacturers of towers, electrical equipment, electrical control and monitoring equipment; architectural and engineering firms, construction firms, labor unions, and other industrial sector elements.[31]

5. MATERIAL NEEDS

Two studies done for ERDA (now DOE) considered the materials needs for commercialization of WECS. One of these studies assessed the possible effects annual production of 8100 WECS units (4 MW units designed for a 7 m/s mean wind speed, or about 15.5 mph) from 1986 to 1990 might have on materials supply. It suggested

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[24] Commercialization Strategy Reports for Small and for Large Wind Systems, op. cit., p. 6 both studies.
[25] Commercialization Strategy Report for Large Wind Systems, op. cit., p. 10.
[26] Commercialization Strategy Report for Small Wind Systems, op. cit., p. 12.
[27] Preliminary Wind Energy Commercialization Plan, part 1, Large Scale Systems, Vol. I, Study prepared for the Federal Energy Administration by the Mitre Corp., January 1977 MTR-7365, op. cit., 8-28.
[28] Solar Program Assessment: Environmental Factors—Wind Energy Conversion. ERDA Division of Solar Energy. March 1977, ERDA 77-4716, p. 18.
[29] Wind Energy Mission Analysis, Executive Summary, study prepared by the Lockheed-California Company for ERDA, October 1976, SAN/1075-1/3, p. 27.
[30] Domestic Policy Review of Solar Energy, op cit., tab J, p. 8.
[31] Preliminary Wind Energy Commercialization Plan, op. cit., pp. 8-12.

that the impact would be relatively insignificant for aluminum, electrical copper, alloy steels and carbon steel. There might be a problem with steel castings but only if the national requirements for steel castings exceeded 304,000 tons per year. The study asserted that proper planning of foundry capacity would probably take care of this potential problem. A 4 MW WECS would require 135 tons of alloy steels, 12 tons of steel castings, 266 tons of carbon steel, 15.5 tons of aluminum alloy sheet, and 5.9 tons of copper wire.[32]

The second study based its assessment on rotors of fiberglass, rather than metal, and assumed no production difficulties except for production of glass fiber and resin for the rotor blades. For these WECS with fiberglass rotors there would be a production requirement of 1,457,000 tons per year if the production is 64,000 1.5 MW units per year (high wind regime of 7 m/s). This would cause an increase of 265 percent in the national requirement and would require a quadrupling of the plastics production capacity. A 1.5 MW WECS would require 96 tons of steel, 1.3 tons of copper, 372 tons of concrete, 8.5 tons of fiberglass, and 2.05 tons of resin.[33]

6. ENERGY EXPENDITURES

In the early years of commercialization the net energy from a WECS would be negative (as it is for any energy source). Maximum negative values of net energy are estimated by one DOE contractor to range from 26 to 33 billion kilowatt hours with energy payback times of 5.2 to 5.9 years.[34] The time required to pay back the energy required to place an individual WECS unit into operation (including mining, processing, forming, fabricating, and transporting all materials and equipment) once mass production has been established is estimated at 0.3 to 0.9 years.[35]

III. Potential Obstacles to R. & D. or Technology Implementation

Most analyses of the potential contribution of wind energy agree that wind energy commercialization will depend on the cost of its electricity being lowered to or below 4¢ per kilowatt hour.[36] Technical and economic considerations are closely intertwined in achieving those cost goals. Other factors, as discussed below, may impact on commercialization of wind energy.

A. Technical

Though no technological breakthroughs are necessary for commercialization of wind energy systems, evolutionary technical improvements and engineering developments are necessary to achieve

[32] Summary of Current Cost Estimates of Large Wind Energy Systems.
[33] Ibid.
[34] Ibid.
[35] Ibid.
[36] See, for example: DOE, Commercialization Strategy for Large Wind Systems, op. cit., pp. 4-6; DOE, Commercialization Strategy for Small Wind Systems, op. cit., pp. 6-7; U.S. Congress. House. Committee on Science and Technology, Oversight-Wind Energy Program, hearings 96th Congress, 1st session, July 30, 1979, pp. 8-9, 26, 130-131; and testimony of Dr. Worth Bateman, DOE, before House Committee on Science and Technology, at hearings on H.R. 5892, Oct. 17, 1979, p. 12 of prepared text (hearings unpublished at this time).

performance goals (for durability and reliability) as well as cost goals.

Economies of scale are presumed for large WECS. However, rotors for megawatt size WECS (with diameters of 200 ft. or more) are theoretically technically possible but remain to be tested and validated onsite over a period of time.

The wind is variable and, for many of their potential uses, WECS need to be coupled with a storage system of some kind for periods when the wind does not blow. A storage system adds to the capital costs of a WECS and can therefore change the competitive situation of wind energy relative to other energy sources. Many storage technologies and mechanisms are under study at the present time, but most of them are not yet economic.

Failure of either the tower or the rotor could pose severe hazards, and R. & D. is ongoing to solve any potential technological safety problems.

Achieving significant contribution of energy from WECS will require their integration into utility grids in large numbers. Technical questions of grid stability and control, and of operational interface need to be resolved.

B. Economic

Costs must be lowered to at least 3 to 4 cents per kilowatt hour before WECS can be competitive with other energy sources for most markets. Current median energy costs for small WECS are 15.4 cents per kilowatt hour [37] and for large WECS (DOE Mod 1 machine) are 10 to 11 cents per kilowatt hour.[38] Technical improvements and engineering developments should help lower costs but economic actions appear essential, too.

There is general agreement that economic incentives are necessary to overcome utility conservatism and to encourage the energy industry to invest in WECS production and utilization.[39] It is difficult to estimate accurately the potential market for large wind systems because (*a*) the utility market is large and diverse, (*b*) the wind resource is highly variable, and (*c*) future fuel prices are uncertain. Without reliable market data, industry appears reluctant to invest sufficient funds to establish quantity production of WECS. Without quantity production, and the resultant cost reductions, the market will remain uncertain.

Further, commercialization of WECS will need an industrial infrastructure to distribute, sell, install, operate, and maintain the machines. At the present time, such a structure does not exist in the industry. The industry will also need to acquire liability insurance for wind systems. Because WECS are of unknown reliability and safety, obtaining insurance may form a barrier to their commercialization.

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[37] Commercialization Strategy Report for Small Wind Systems, op. cit., p. 10.

[38] Commercialization Strategy Report for Large Wind Systems, op. cit., p. 20.

[39] See, for example, DOE Commercialization Strategy Report for Small Wind Systems, op. cit., pp. 19-38; DOE Commercialization Strategy Report for Large Wind Systems, op. cit., pp. 16-36; Preliminary Wind Energy Commercialization Plan, op. cit., pp. 7-4 to 7-10; and Marshall Merriam, Wind Energy Use in the United States to the Year 2000, study prepared for the Federal Energy Administration, October 1977, pp. 4-8.

Integration of WECS with utility grids poses questions of capacity credit and energy value which must be resolved for economic utilization of WECS in a utility setting.

C. Environmental

There appear to be no major environmental obstacles to commercialization of WECS. A minor consideration is the television broadcast interference caused by the rapidly rotating blades of WECS. This is a localized effect (within a few miles of the WECS) and site selection, along with selection of certain materials for the blades, can possibly ameliorate this problem. Cable TV may be another solution to this problem.

D. Social

Currently, public acceptance of WECS is high. However, WECS are highly visible on the landscape and the siting of either individual WECS or groups of WECS (in a wind "farm") may eventually have to be limited to land which is outside scenic and/or urban areas.

E. Political

Other than the necessity, cited by some proponents, to obtain administration support for increased funding for Federal wind research, development and demonstration programs, no political problems appear to exist.

F. Legal/Regulatory

There are potential legal difficulties concerned with the siting of WECS, but these are not considered major impediments. A body of statutes which sets precedents for resolving legal issues regarding wind has not yet been developed. Potential areas of concern include zoning; State and local building, safety, and housing codes; State utility commission certification procedures; ownership of "wind rights;" and lack of legal means of regulating upwind obstructions.

G. Siting

Siting is crucial to economic production of energy from the wind. More data and analysis of potential wind sites is essential to achieve maximum output from WECS when they are installed.

There have been suggestions that offshore siting of WECS could result in the generation of large amounts of electrical power. However, at the present time, the high cost of building platforms in the ocean and transmitting electricity back to shore, in addition to the technical problems of carrying out those activities, indicate that offshore siting of WECS is not now economical. In addition, placing WECS offshore raises a number of domestic and international legal questions which would have to be resolved prior to their installation.[40]

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[40] Coit, Lynde, Wind Energy, Legal Issues and Institutional Barriers, study prepared by the Solar Energy Research Institute for the Department of Energy, SERI/TR-62-241, June 1979, p. 12.

IV. Potential Contribution to Future U.S. Energy Supplies

A. Contribution by 1990

Large wind systems are anticipated by DOE to be able to supply 0.19 quads of energy by 1990.[41] Small wind systems are anticipated by DOE to be able to supply 0.11 quads.[42]

B. Contribution by 2000 or Beyond

Large wind systems are anticipated by DOE to be able to supply 2.1 quads of energy by the year 2000 [43] out of the almost 125 quads estimated by DOE to be required to meet U.S. energy needs at that time. However, a summary of market penetration estimates for large machines range from .01 to 6.0 quads, with the median being around 2.0.[44] Small wind machines are estimated by DOE to be able to contribute 0.32 quads by 2000.[45]

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[41] Commercialization Strategy Report for Large Wind Systems, op. cit., p. 10.
[42] Commercialization Strategy Report for Small Wind Systems, op. cit., p. 12.
[43] Commercialization Strategy Report for Large Wind Systems, op. cit., p. 10.
[44] Ibid., p. 11.
[45] Commercialization Strategy Report for Small Wind Systems, op. cit., p. 12.

ANALYSIS AND DISCUSSION*

In the preceding sections we have examined an extensive array of energy technologies that offer a diversity of opportunities to tap new domestic sources of energy, to increase the reserves to production ratio of our resources, or to improve the efficiency with which we process and deliver energy to the ultimate industrial or individual consumer. The picture revealed is a complex montage of quantities of energy, time elements, and private and public expenditures. This provides us with a broad appreciation of where our future energy rewards are to be found. It also can be used as a frame of reference for a general comparison of the Federal funding levels needed to stimulate research and to activate the process leading to the commercial adoption of new or improved technologies.

Among the many factors that control where the most fruitful rewards from energy research are to be found, the following are particularly significant:

Magnitude.—The estimated magnitude of the physical stock or flow of energy to be employed.

Experience.—The familiarity of energy users with the energy form and its technology, particularly with respect to the adaptability of that energy form and its technology to present practice.

Costs.—The expected future cost per delivered unit of energy (BTU or Kwh) and the time profile of capital expenditures as they relate to market competitiveness of the fuel or energy to be produced, or to the magnitude of capital investment required to begin production of that fuel or energy.

Timing.—The duration and current degree of learning and/or production experience in the progression from basic research through commercial adoption, insofar as these factors might influence the current level of R. & D. expenditures and the timing of the energy pay-off.

As noted in the Introduction, the mix of energy sources now used in the United States is not a mere happenstance. It is a reflection of basic economic and physical conditions which have favored coal, petroleum, natural gas, nuclear fission, hydropower, and fuel wood. For many decades these sources offered significant quantities of energy that were accessible, readily usable, and inexpensive. Nor should we forget that the aggregate potential of these common resources still has not been fully exploited. They continue to possess the important advantage of using technologies familiar to industry and individual consumers. Moreover, the remaining endowments of these resources still offer accessibility and ready utility. The key uncertainties are how much more can they usefully contribute and at what cost.

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In contrast, the less familiar sources of energy have not been employed in the past because they have one or more of the following drawbacks: lack of development as proven technologies, resource limitations, less favorable physical characteristics, lack of user familiarity, or comparative economic disadvantages. If we now wish to facilitate or accelerate their entrance into the mainstream of the U.S. energy economy, then expenditure of Federal dollars may be required to compensate for some of these restraints. However, the rewards can be attractive if government expenditures are directed toward favorable combinations of energy potential plus proper timing of deliverability. To this must be added considerable sensitivity to public acceptance of any new technology.

The Federal role in research, development, demonstration, and commercialization cannot be determined as though it operated in a vacuum. The private sector concurrently sets its own goals and makes its own significant and continuing contributions. Its general behavior in this process is reasonably predictable. Basically the private endeavor tends to minimize research involving long term returns or to avoid large initial capital investment in uncertain development projects. From the private firm perspective this is rational behavior. Greater capital risks or long pay-back periods are not attractive to the corporate research manager who recognizes that performance is evaluated on an annual or relatively short term basis by executives and stockholders. Thus we can expect the involvement of the private firms in energy R. & D. is likely to be greatest where it tends to be an extension of past energy choices. For instance, oil companies are likely to be naturally more comfortable in pursuing ways to produce heavy oils, and utilities will probably be more attracted to contemplating cogeneration, than venturing into less familiar energy products and processes. The importance of recognizing this behavior pattern is that some Federal research dollars will augment the private effort in certain kinds of energy R. & D., while in other areas the Federal effort may have to carry a much larger proportion of the burden.

The various technologies examined in this report must be reviewed and compared in this setting. It is clear from the outset that a number of choices are available to us. First, for example, there is the choice between new departures in energy supply and the further refinement of established supply systems. The various efforts must be funded by different combinations over time of public and private funds. Nor can this process avoid the inevitable difficulties encountered in the early stages of use of new technologies. As a consequence, for the balance of this century, the energy supply rewards per Federal energy research dollar frequently may tend to be higher if we intensify our exploitation of conventional energy resources versus turning to new technologies and more "exotic" energy sources. This is a reflection of the extensive quantities of conventional resources that still remain to be produced and the ready adaptation by energy producers and users to improvements in "old" technology. But equally important is the sharing of the R. & D. plus commercialization costs by public and private sources.

Second are those Federal research opportunities which have a favorable combination of good resource potential coupled with a relatively low level of future research dollar requirements. Here, the rewards can be attractive even if the private sector is not extensively involved at present. In these cases, the amount of energy to be obtained over the next two decades may be large, or we may have the advantage of being "well along" the learning curve. Once these kinds of technologies are pushed successfully past the demonstration stage, the private sector can be expected to enter rather quickly into actual commercialization.

Third are those research opportunities that include those R. & D. pathways where we cannot be very optimistic about the amount of energy available or retrievable in the next two decades from a given energy source. This may or may not be coupled with a need for large expenditures in research and demonstration plants. This kind of combination of unfavorable factors does not necessarily suggest that Federal funds should not be expended, but that the energy returns from these technologies (1) may not be captured prior to the year 2000, *or* (2) may not produce large returns per Federal dollar of R. & D. support, according to current estimates. This is not to say that Federal support is unwarranted in these instances, however, or that appreciable Federal support may not be appropriate at present for some of these technologies. Further, it must be recognized that the pace of development of some of these technologies is directly linked to Federal R. & D. policies, so that earlier commercialization could result from greater support levels or changes in development schedules.

Given these characteristics of energy R. & D., the expenditure patterns that we now anticipate from the private sector and the published plans of the Federal establishment, primarily the Department of Energy, the question is where do the various research activities described in the individual chapters of this study fit into our future energy picture?

The estimates provided here of the expected returns from energy R. & D. do not include the returns expected from customary, gradual improvements in our present methods of producing, processing, and delivering energy. The individual chapters have included an examination of the state-of-the-art of producing coal, petroleum, natural gas, hydropower, and nuclear energy. However, in this section, our comparison of the various energy R. & D. efforts will include only significant departures from past practices. Thus we will include additional energy from the commercialization of tertiary recovery of petroleum but will not account for the continuing improvement of recovery using primary and secondary methods. Research on how to produce geopressured methane is included, but expected improvements in drilling to greater depths or in deeper water offshore are not. The conversion of coal to liquids and gases is included but not improvements in underground mining efficiency. Demonstration of means to use low-head hydropower is included, but improvements in the design of dams and turbines is not.

Table 12 clusters the technologies into groups based upon the primary form of the original source of energy, e.g., coal, direct sunlight, or moving water, as shown in the first column. The second column of the table shows "best guest" estimate of the quantity of fuel or energy that possibly may be employed or delivered by the technology, without respect to any given time frame.

As discussed above, many of the energy resources and their technologies are already part of the Nation's developed energy capability: the third column of Table 12 indicates what portion of the resource potential is currently developed either in terms of energy capacity (for flow resources) or as known reserves (for depletable resources) as specified in the texts of the previous chapters. The fourth column shows what that capacity or reserve is now contributing to meet current U.S. energy demand. The fifth column gives the most recent available Federal R.D. & D. support figures for the technology. The last two columns provide an indication of current thinking regarding the contributions the technology might be expected to make to U.S. energy supplies in 1990 and 2000, typically as a range of predictions by various experts in the field. A comparison of 1990 and 2000 can also give a sense of the pace of development, and may indicate whether the trend after 1990 will be one of continued improvement, stagnation, or decline.

TABLE 12. SUMMARY MATRIX OF ENERGY TECHNOLOGIES

TECHNOLOGY	POTENTIALLY RECOVERABLE RESOURCE 1/	DEVELOPED CAPACITY OR RESERVES	CURRENT CONTRIBU-TION	CURRENT FEDERAL RD&D EXPENDITURE, millions	ESTIMATED POTENTIAL CONTRIBUTION 2/ 1990	2000
<u>Conventional energy sources:</u>						
Coal Combustion	437 billion tons	283 billion tons	770 million tons (1979)	102.5 (FY81)	1.1-1.2 billion tons	1.2-1.7 billion tons
Light-water nuclear reactors	77 million tons U_3O_8	2.5 million tons U_3O_8	52 Gw_e	412 (FY80)	131-182 Gw_e	131-300 Gw_e
Natural gas	322-655 trillion cu ft	194.9 trillion cu ft	19.9 trillion cu ft/yr	2.37	17.1 trillion cu ft/yr	----
Oil	50-127 billion barrels	27.1 billion barrels	2.96 billion barrels/yr	21.77 (FY80)	2.2 billion barrels/yr	----

TECHNOLOGY	POTENTIALLY RECOVERABLE RESOURCE 1/	DEVELOPED CAPACITY OR RESERVES	CURRENT CONTRIBU-TION	CURRENT FEDERAL RD&D EXPENDITURE	ESTIMATED POTENTIAL CONTRIBUTION 2/	
					1990	2000
A. Coal-based technologies:						
1. Coal liquefaction	437 billion tons	None	Negligible	250.3 (FY80) 523.9 (FY81)	100-200 thousand barrels oil equivalent/day	0.5-1.2 million barrels oil equivalent/day
2. High-Btu coal gasification	437 billion tons	Negligible	Negligible	85 (FY80)	0.5-1 billion cu ft/day	3.3 trillion cu ft/day
3. Magnetohydrodynamic power generation	437 billion tons	None	None	80 (FY79) 71 (FY81 req)	500 Mw_t	1-3 Gw_t
4. Other coal technologies: Combined-cycle coal gasifier	437 billion tons	Negligible	None	None	0.1 Q	3 Q
5. Fluidized bed combustion	437 billion tons	Negligible	60 Mw_e	37.2 (FY 81 req)	0.8 Q	6.0 Q
6.-7. Low- and medium-Btu	437 billion tons	Negligible	Negligible	19 (FY81 req)	0.16-0.2 Q	1 Q

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TECHNOLOGY	POTENTIALLY RECOVERABLE RESOURCE 1/	DEVELOPED CAPACITY OR RESERVES	CURRENT CONTRIBU- TION	CURRENT FEDERAL RD&D EXPENDITURE	ESTIMATED POTENTIAL CONTRIBUTION 2/ 1990	2000
B. Direct-sunlight technologies:						
8. Agricultural and	----	Negligible	Negligible	38.1 (FY81 request, post-revision)	Negli- gible	0.2 Q
Industrial Process Heat Applications					1.0 Q	2.0 Q
9. Passive Solar Energy	7.4 Q/yr	Negligible	Negligible	33.4 (FY81 req., post- revision)	0.4 Q	1.1Q
10. Photovoltaic energy conversion	----	Negligible	Negligible	160.6	0.1 Q	0.8 Q
11. Satellite power stations	----	None	None	5.5 (FY80)	None	None
12. Solar heating and cooling for buildings	----	Negligible	250,000 barrels oil equiv- alent/yr	45.2 (FY81 req., post- revision)	0.7 Q	2.4 Q
13. Solar thermal power con- version	----	None	Negligible	117 (FY 81 req)	Negli- gible	0.4 Q

TECHNOLOGY	POTENTIALLY RECOVERABLE RESOURCE 1/	DEVELOPED CAPACITY OR RESERVES	CURRENT CONTRIBUTION	CURRENT FEDERAL RD&D EXPENDITURE	ESTIMATED POTENTIAL CONTRIBUTION 2/	
					1990	2000
C. Fluid hydrocarbon technologies:						
14. Heavy oil	7.47-20.5 billion barrels	----	500 thousand barrels/day	7.25 (FY80) 7.9 (FY81)	1 million barrels/day	1 million barrels/day
15. Oil shale	----	None	None	28.2 (FY80) 36 (FY81)	60-250 thousand barrels/day	180-450 thousand barrels/day
16. Unconventional gas	782-3140 trillion cu ft	12.7-13.5 trillion cu ft	1.1 trillion cu ft/yr	66.5 (FY 81)	2.1-9.6 trillion cu ft/yr	----

TECHNOLOGY	POTENTIALLY RECOVERABLE RESOURCE 1/	DEVELOPED CAPACITY OR RESERVES	CURRENT CONTRIBUTION	CURRENT FEDERAL RD&D EXPENDITURE	ESTIMATED POTENTIAL CONTRIBUTION 2/ 1990	2000
D. Organic conversion technologies:						
17. Energy from municipal solid wastes	----	Negligible	10 thousand barrels/ day oil equivalent	13.5 (FY80)	20.85 thousand barrels/ day oil equivalent	----
18. Ethanol	28.8 billion gallons/yr 4/	120 million gallons/yr	120 million gallons/ yr	Combined ethanol and methanol:	7.2-41.2 billion gallons/ yr	54 billion gallons/ yr
19. Methanol	447.3 trillion gallons from coal 250 billion gallons from wood 8.0-11.8 billion gallons from municiple solid waste 5/	Negligible	Negligible	18.45 (FY80) 24.9 (FY81)	Negligible	14 billion gallons/ year

TECHNOLOGY	POTENTIALLY RECOVERABLE RESOURCE 1/	DEVELOPED CAPACITY OR RESERVES	CURRENT CONTRIBU-TION	CURRENT FEDERAL RD&D EXPENDITURE	ESTIMATED POTENTIAL CONTRIBUTION 2/ 1990	2000
E. Nuclear technologies:						
20. Advanced converter reactors	7 million tons U_3O_8 1.6 million tons ThO_2	2.5 million tons U_3O_8 150 thousand tons ThO_2	None	47(FY80)	15 percent savings U_3O_8	30 percent savings U_3O_8
21. Breeder reactors	7 million tons U_3O_8 1.6 million tons ThO_2	2.5 million tons U_3O_8 ore; 300,000 tons depleted U_3O_8 150 thousand tons ThO_2	None	742 (FY80)	None	Negligible
	(See footnote 5)					
22. Fusion	Lithium--several thousand years Deuterium--millions of years	None	None	447 (FY80)	None	None
F. System efficiency technologies:						
23. Cogeneration	----	None	None	25.87 (FY81)	0.26-1.52 Q	2-6 Q
24.-25. Conservation/efficiency	----	----	----	----	----	----

TECHNOLOGY	POTENTIALLY RECOVERABLE RESOURCE 1/	DEVELOPED CAPACITY OR RESERVES	CURRENT CONTRIBUTION	CURRENT FEDERAL RD&D EXPENDITURE	ESTIMATED POTENTIAL CONTRIBUTION 2/ 1990	2000
G. Other technologies:						
26. Fuel cells	See: coal, oil, natural gas	None	None	2(FY81)	Negligible	2.5 percent fuel saving
27. Geothermal energy	23 Gw_e	1300 Mw_e 15-16 Mw_t	663 Mw_e 15-16 Mw_t	36 (FY81)	10 Gw_e 0.2-0.4 Q_t	20-40 Gw_e 0.5-2 Q_t
28. Hydrogen	----	None	None	23.1 (FY80) 23 (FY81)	None	None
29. Low-head hydropower	16.4 Gw_e	3 Gw_e	15 billion kwh/yr	18 (FY80) 18.2 (FY81)	6 Gw_e	18.9 Gw_e
30. Ocean thermal energy conversion	100 Gw_e	None	None	40 (FY 80) 39 (FY 81)	None	3 Gw_e
31. Wind energy	2,000 Gw	3 Mw	3 Mw	63.4 (FY80) 77.9 (FY81--passed House)	Negligible--2.1 Q	0.1-6 Q

FOOTNOTES TO TABLE 12

1/ Data represent "best-guess" estimates by acknowledged experts of the quantities of material available domestically that may be economically recoverable by the year 2000.

2/ Data represent "best-guess" estimates by acknowledged experts of the energy that may be available domestically by the respective times indicated.

3/ Figure represents 27.8 billion gallons from grain and 1.0 billion gallons from sugar, assuming theoretical use of the total U.S. grain harvest--plus grain that could be produced from acreage currently idled under Federal supply control programs--and the total U.S. sugar harvest.

4/ Figure assumes conversion of all available coal, wood, and municipal solid waste to methanol at present estimated conversion rates.

5/ Breeder reactors can produce approximately 60-100 times as much energy per ton of uranium as light water reactors or advanced converter reactors.

A word of caution is in order at this point. The expectations for 1990 and 2000 are supply-side judgments of the potential for improving domestic energy output, as arrived at by various experts over the past several years. In general, they do not reflect a detailed, comparative analysis of the future costs of these various energy outputs yielding a forecast of what would actually be produced in competition with one another. Rather, these admittedly intuitive estimates include a general, implicit inference that the costs of the energy that might be derived from these sources (presuming that the R.D. & D. effort is successful) would probably be economically competitive in those future years. Therefore, these estimates are not to be considered as predictions of the quantities that would actually be produced and consumed in a competitive energy market. Nor should they be aggregated to arrive at a total contribution.

Each technology was then considered qualitatively from the standpoint of its current state of development, the current level of Federal R.D. & D. support, possible constraints that might serve to limit or impede its smooth development, the R.D. & D. yet to be accomplished before it appears likely to contribute significantly to U.S. energy supplies within the next two decades, and the estimated potential contribution that it might conceivably make by 1990 and 2000 provided that a suitable R.D. & D. effort should be both adequately supported and successful.

Based upon this qualitative—and admittedly very sketchy—analysis, the 31 technologies were arranged in three major categories: I, those which, regardless of the level of Federal research support, appear to have little prospect of making a significant energy contribution during the next two decades; II, those which may provide energy contributions but which do not appear to require appreciable additional Federal research support; and III, those which may conceivably provide contributions by the year 2000 and most likely will require further Federal support. The distribution of the technologies among these three categories is shown in table 13.

TABLE 13. ORGANIZATION OF ALTERNATIVE ENERGY TECHNOLOGIES IN TERMS OF ESTIMATED ENERGY RETURN AND FEDERAL SUPPORT REQUIRED

Category I. Little or no anticipated contribution prior to 2000 but requiring Federal R&D support

- Breeder reactor
- Fusion
- Hydrogen
- Satellite power stations

Category II. Significant contribution by 2000 anticipated but Federal support considered negligible

- Cogeneration
- Conservation/efficiency
- Passive solar

Category III. Significant contribution by 2000 anticipated and Federal R&D support required

- Advanced converter reactors
- Agricultural and industrial process heat applications
- Coal liquefaction*
- Energy from municipal solid wastes
- Ethanol
- Fuel cells
- Geothermal energy
- Heavy oil (including enhanced gas recovery
- High-Btu coal gasification*
- Low-head hydropower
- Magnetohydrodynamic power generation*
- Methanol
- Ocean thermal energy conversion*
- Oil shale
- Other technologies for the utilization of coal:
  - Atmospheric fluidized bed combustion
  - Combined cycle gasifier
  - Low- and medium-Btu coal gasification
- Photovoltaic energy conversion*
- Solar heating and col cooling for buildings
- Solar thermal power conversion*
- Unconventional gas
- Wind energy

*These technologies are only expected to make a contribution by year 2000 if they receive extensive Federal RD&D support.

Category I lists four energy technologies from the table 12 matrix for which there does not appear to be a strong expectation for a measurable quantity of energy to show up in the national energy accounts by 2000. These are breeder reactors, fusion reactors, the use of hydrogen as an energy substitute for more conventional energy forms, such as natural gas, and satellite power stations. At this point it is difficult to make refined economic judgments about their long-run potential. According to current expectations their future contributions will not begin to be realized until after the year 2000. For example, a comparatively modest amount of research appears to be needed at the moment to continue to examine the potential for hydrogen as a general purpose energy transmission medium. Fusion research is both highly technical and operating at the frontier of science, so it may prove quite costly to move it forward. Space-related activities are comparatively expensive, so the building and testing of a satellite power plant could also prove to be exceedingly costly. In these latter two cases, while the initial capital outlays will be large and perhaps should be begun, there would appear to be adequate opportunity over an extended research period to examine the wisdom of the level and direction of further effort. Breeder reactors might possibly be accelerated in their development and commercialization, but policy problems such as nuclear proliferation make such an acceleration highly unlikely in the immediate future. In view of the relatively long time-frame associated with each of these technologies, their further consideration was taken to be outside the scope of this report.

Category II involves four areas of research where the need for Federal R. & D. would appear either negligible or non-existent. In cases such as these the process of bringing on these technologies or methods does not necessarily require Federal R. & D. support. Rather the situation would seem to require private investment of time and money to determine on an operational basis whether the possibility for improving the efficiency of supply or delivery systems in a certain way will prove economically attractive and reasonably reliable. This is the circumstance faced in passive solar systems, cogeneration, and such conservation/efficiency possibilities as coal slurry pipelines, general improvements in energy system efficiencies, cryogenic transmission, and the development of inter-tied power grids. Energy efficiency through these endeavors is only worth seeking if there will be a true net saving realized. In all of these cases something between 0.1 and 3.0 quads of energy saved might be involved as we try to meet our energy supply needs in 2000. The question appears not so much one of research, but whether an individual or firm will be sufficiently attracted to try these approaches. Using the sun to heat a shelter or a home is not really new; it has been practiced for centuries. Various kinds of dual cycles, cogeneration, and other energy producing systems become useful when energy costs are high and the right configuration is present. The knowledge that electricity moves better at lower temperature or that coal may be piped in water suspension is not new, but it requires the transmission companies to determine the feasibility of so doing. In all of these cases, the introduction and evolutionary refinement of the technologies would appear to require the normal involvement of the manufacturers, producers, and consumers, rather than the expenditure of Federal R. & D. funds. Inasmuch as in this report we are primarily concerned with the prospective energy return from federally-supported R.D. & D., these technologies were not considered germane.

It should be emphasized that the above comments concerning the technologies grouped into categories I and II in no way represent a dismissal or downgrading of the potential contribution these technologies might make to future U.S. energy supplies. Continued Federal R.D. & D. may well be justified for technologies listed in category I, and continued private-sector support may be forthcoming for technologies listed in category II. No judgment of the merits of such support, either Federal or private, is intended here. It should also be noted that, were policies adopted to accelerate their rapid deployment, some of the technologies—and especially the breeder reactor—now given in Category I might well be given in Category III, instead.

The remaining 23 technoligies, listed in category III, were then regrouped—as shown in table 14—according to whether their estimated energy returns by the year 2000 were likely to be large, moderate, or small for a limited, moderate, or extensive Federal investment. These estimates of both possible energy returns and extent of Federal support are of course qualitative judgments of a somewhat abritrary nature and simply represent a "best guess" as to what our future course of action may be, based upon the information given in each of the individual technology chapters

TABLE 14. ESTIMATED RETURN ON INVESTMENT FOR TECHNOLOGIES REQUIRING SIGNIFICANT FEDERAL RD&D SUPPORT (CATEGORY III)

Estimated Return	Extent of Federal RD&D Support Required		
	Limited Support	Moderate Support	Extensive Support (1)
Large	Heavy oil Unconventional gas		
Moderate	Combined-cycle gasifier Ethanol and methanol (2) Low- and medium-Btu coal gasification Solar heating and cooling of buildings Wind energy	Advanced converter reactors Agricultural and industrial process heat applications Fluidized bed combustion Oil shale	Coal liquefaction Photovoltaic energy conversion
Small	Energy from municipal solid wastes Geothermal energy Low-head hydropower	Fuel cells	(3) High-Btu coal gasification Magnetohydrodynamic power generation Ocean thermal energy conversion Solar thermal power conversion

(1) Without extensive Federal RD&D support and a commitment to commercialization by the year 2000, the technologies listed in this column might well have been placed in Category I of table 13, rather than in Category III.

(2) Combined mid-range estimate (see table 12). Upper estimate would place these techniques in the long-range category.

(3) Were policies to be adopted to accelerate their rapid deployment, some of the technologies now listed in Category I of table 13--the breeder reactor in particular, and possibly satellite power stations--might well be listed here, instead, under Category III.

Considering first the technologies listed in table 14 under "Limited Support," the group includes heavy oil, gas from unconventional sources, the combined-cycle gasifier, alcohol fuel (ethanol and methanol), low- and medium-Btu coal gasification, solar heating and cooling for buildings, wind energy, energy from municipal solid wastes, geothermal energy, and low-head hydropower. Several of these technologies have a number of factors in common. Quite striking is that most of them are not new—we are well along the learning curve for many of them. Drilling for oil and gas and the movement of fluids in the reservoir have been studied for many years. The production of alcohols—and especially ethanol—from a variety of raw materials, as well as their combustion in internal combustion engines, is familiar technology. We have been using wind power for centuries, and its conversion to electric power is a simple process. Although these technologies require some further research, the primary need is to demonstrate that they have commercial utility in today's energy markets. This should not involve large expenditures of Federal funds over an extended period. Substantial private sector involvement can be expected, first in research and later in product commercialization once the technology is shown to be usable. Finally, the energy sources being tapped are of appreciable size, so that the amounts of energy that each could contribute by 1990 or 2000 is significant. Thus these technologies possess all of the key factors—resource magnitude, familiar technology, potential for a competitive cost level, and good timing—that make likely the prospect of a moderate-to-large energy return for rather limited Federal support.

For several other technologies listed under "Limited Support," the key factors also tend to be mostly favorable but the combination appears less strong. For example, the combined cycle gasifier would appear to be a good prospect but has the disadvantage of not being quite as familiar a technology and may have some limits in its early applications. In contrast, low- and medium-Btu gasification are already "on-the-shelf" technologies that merely need some demonstration efforts. However, there may be restraints on the general utility of this quality of gas as an industrial fuel. Solar heating and cooling techniques area also well-known and may prove generally useful, but their widespread application still faces a number of institutional, rather than technological, obstacles. Solid waste conversion seems to have some favorable combinations of economic factors, but its operational feasibility in actual urban settings needs to be further established, and the total resource recovery potential has upper bounds. Geothermal heat and the use of our remaining undeveloped hydropower both suffer from either the availability or usability of specific sites. Other than a lack of experience in finding and developing geothermal resources, neither of these two relatively low-grade energy sources seem to require a "pure" research effort. Thus, although none of these technologies would appear to require more than limited Federal support, the above factors may serve to preclude more than a small-to-moderate energy return for that support.

Considering next those technologies included under "Moderate Support", we encounter technologies definitely less familiar or well-developed than are those of the above group and which for various reasons can be expected to require considerably more Federal support for their development. For example, the improvement of future light water nuclear reactors involves achieving a higher thermal efficiency of the plant and more complete "burning" of the fuel charge. Better reactor design would enhance our efficient use of uranium resources as well as reduce costs. However, this kind of contribution to supply is limited both by the number or reactors that might be involved by the end of the century as well as theoretical limits to achievable uranium burn-up. Agricultural and industrial solar process heat require a definite research investment to demonstrate their usefulness, but even if proved usable there are limits on where such low grade heat will be useful. While oil shale technology is not new, it has never been tested on a commercial scale. The pace of its development, plus the large front-end expenditures, seems to suggest the need for rather deliberate progress over an extended period of time. Fluidized-bed combustion, like the combined-cycle gasifier discussed previously, also appears a good prospect but suffers the disadvantage of lack of familiarity and possible limitations in its early application. The fuel cell has a very limited potential for producing commercial energy by 2000, and the planned R. & D. funding is not very large. Thus, these "Moderate Support" technologies—although considered as potentially requiring significantly greater Federal support than the "Limited Support" technologies—may, over the next two decades, at least—involve a somewhat lesser energy return.

Finally, we consider under "Extensive Support" those technologies which appear to require the greatest Federal support but which, at least by the year 2000, may not provide commensurate energy returns. With one exception, the group reflects primarily the large amount of Federal R. & D. support needed to achieve future production of competitive energy. Moreover, the prior experience with these technologies, while not necessarily totally new, does not include familiarity on a large, commercial scale. This is true for coal liquefaction, high-Btu gasification, photovoltaic conversion, and solar thermal conversion. In the case of magnetohydrodynamics, both research and operating experience (demonstration) are required to move the state-of-the-art from its present basic level through plant demonstration. Without changes in current programming, there is little reason to expect any significant amount of energy output from these technologies by 2000. Ocean thermal energy conversion may be the one exception. In this case the amount of funds needed to demonstrate its feasibility is not as large as for the others in the group, but the potential contribution by 2000 would appear to be relatively modest.

In reviewing the 23 technologies examined in table 14, it is obvious that in some situations a rather small amount of Federal support, frequently coupled with an important effort by the private sector, may yield large energy rewards over the next twenty years. These situations involve innovation in the manner in which we extract oil and gas from the ground and the way in which we convert very familiar sources of energy—agricultural products, coal, direct heat of the sun, and wind energy—into useful forms of energy that our energy consumers will find have become useful as well as economic. It should also be noted that, without extensive

Federal R.D. & D. support and a commitment to commercialization by the year 2000, the technologies listed in the last column of the table might well have been placed in Category I, rather than in Category III, of table 13.

There are also some important efficiences to be gained in our supply stream that do not actually provide new energy but make it possible to use less of our original energy resources in producing and transmitting energy to the user. In many cases, although the energy returns may not be as great as in some categories, R. & D. is attractive because the Federal support requirements are low while an aggressive energy industry takes advantage of opportunities on its own. Additionally, there are a number of R. & D. efforts that should be pursued cautiously because the development effort is large or we should avoid exaggerated expectation as to how much can be accomplished by R. & D. in only two decades. And finally, although outside the time-frame of this report, and therefore not included in table 14, there are technologies that can beneficially be pursued because of the energy contributions they may make beyond the year 2000.

The DOE now predicts that the United States will be using between 75.4 and 84.3 quads of energy in 2000, not including conversion losses estimated at about 29 quads.[1] Thus, no single one or combination of the technologies discussed in this report can satisfy all of that need, no matter what our R. & D. might attempt and succeed in doing. Given that some will fail to live up to expectations, some will do better than we now hope, or we may push R. & D. harder than now anticipated, it does appear reasonable to assume that R. & D. will make some significant changes in our mix of energy sources and technologies by 2000. But much of the familiar pattern of what currently supplies the bulk of our raw energy supplies will still remain visible as we enter the next century.

With our present reliance on foreign oil for most of our incremental energy supplies, it does seem wise to explore our R. & D. options vigorously. Table 14 provides a qualitative indicator as to the energy returns which can be expected and the extent of Federal support that may be required for the further development of each of these technologies.

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[1] Energy Information Administration. 1979 Annual Report to the Congress, p. 165 (table 5.4).

LIST OF ABBREVIATIONS AND ACRONYMS

AECL—Atomic Energy of Canada, Ltd.
AFR—away from reactor
API—American Petroleum Institute
ASHRAE—American Society of Heating, Refrigerating and Air Conditioning Engineers
BATF—Bureau of Alcohol, Tobacco and Firearms
bcf—billion cubic feet
BEPS—building energy performance standards
BOS—balance of system
bpd—barrels per day
Btu—British thermal unit
BWR—boiling water reactor
CANDU—Canadian deuterium reactor
CDIF—component development and integration facility
CFTL—core flow test loop
COTV—cargo orbital transfer vehicle
CRBRP—Clinch River breeder reactor project
DEMO—demonstration reactor
DOE—Department of Energy
DPR—domestic policy review
EBFA—electron beam fusion accelerator
EBR—experimental breeder reactor
EEZ—exclusive economic zone
EIA—Energy Information Administration
EMB—Energy Mobilization Board
EPR—engineering prototype reactor
EPRI—Electric Power Research Institute
ERDA—Energy Research and Development Administration
ESCOE—Engineering Societies Commission on Energy, Inc.
ESW—energy from solid waste
ETF—engineering test facility
FERC—Federal Energy Regulatory Commission
FFTF—fast flux test facility
FPUP—Federal photovoltaic utilization program
GAO—General Accounting Office
GCFR—gas cooled fast reactor
GCRA—Gas Cooled Reactor Associates
GEO—geosynchronous earth orbit
GRIST—gas reactor in-pile safety test
Gw—gigawatt
HBA—Helium Breeders Associates
HLLV—heavy lift launch vehicle
HTGR—high temperature gas reactor
HUD—Housing and Urban Development (Department of)
HWR—heavy water reactor
IAE—International Energy Agency
IAEA—International Atomic Energy Agency
IDB—industrial development bonds
INEL—Idaho National Engineering Laboratory
INFCE—international nuclear fuel cycle evaluation
INTOR—international tokamak reactor
JET—joint European torus
JFPCC—Joint Fusion Power Coordinating Committee
kwh—kilowatt hour
LEO—low earth orbit
LMFBR—liquid metal fast breeder reactor
LOFT—loss of fluid test facility
LSA—low-cost solar array
LWBR—light water breeder reactor

LWR—light water reactor
mbd—million barrels per day
MFTF—mirror fusion test facility
MHD—magnetohydrodynamics
m/s—meters per second
MSBR—molten salt breeder reactor
MSRE—molten salt reactor experiment
MSW—municipal solid waste
Mw—megawatt
Mwe—megawatts-electric
Mwt—megawatts-thermal
NASA—National Aeronautics & Space Administration
NRC—Nuclear Regulatory Commission
NSF—National Science Foundation
OEIC—ocean energy industrial complex
OS/IES—on site/integrated energy system
OTEC—ocean thermal enegy conversion
PBF—power burst facility
PCI—pellet-clad interaction
PLBR—prototype large breeder reactor
PLV—personnel launch vehicle
POTV—personal orbital transfer vehicle
psi—pounds per square inch
PWR—pressurized water reactor
R. & D.—research and development
R.D. & D.—research, development, and demonstration
RANN—research applied to national needs program
RDF—refuse-derived fuel
SASOL—South African Coal, Oil and Gas Corporation
SEINM—Solar Energy Institute of North America
SFC—Synthetic Fuels Corporation
SPS—solar power satellite
tcf—trillion cubic feet
TFTR—Tokamak fusion test reactor
USGS—U.S. Geological Survey
VHTR—very high temperature reactor
WECS—wind energy conservation system

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