Chapter 3

# Technologies for Energy Supply and Conversion

# CONTENTS



## *Figures*



## *Tables*

Chapter 3

# Technologies for Energy Supply and Conversion

Despite stable energy supplies and prices, recent events in the Middle East and declining domestic oil production have triggered concern over the long-term adequacy of U.S. energy supplies. In addition, environmental considerations, e.g., global warming and high ozone levels in urban areas, will continue to have an impact on energy supply choices.

A variety of technologies (table 3-1) show promise for replacing and/or extending the Nation's oil and gas resources and providing other options. Included are technologies for improving coal combustion, electric power generation, and nuclear and renewable energy supply options. This chapter begins with a brief summary of U.S. energy resources and ends with a discussion of nontechnical factors that could affect U.S. supply options.

## U.S. ENERGY SUPPLY

Fossil fuels continue to dominate the U.S. energy market. Table 3-2 shows U.S. energy production by source from 1970 to 1989. Coal accounts for the largest share of domestic energy production today. The U.S. Energy Information Administration (EIA) indicates that there are enough coal reserves to sustain current levels of production for more than 200 years. Most of the coal (62 percent) is mined east of the Mississippi River, but Western coal has been increasing its share since the mid- 1960s. The growth in Western coal production is partly a result of environmental concerns over Eastern high-sulfur coal. Also, surface mining, which is more prevalent in the West, has a higher productivity rate than underground mining.[1]

Coal has been the United States' major energy export. Japan, Italy, and Canada are our leading customers. Together they accounted for about 41 percent of total coal exports in 1989.[2] In the United States, electric utilities are the largest market for coal.

The United States has used more than half of its oil and gas, and estimates of undiscovered recoverable resources are inherently uncertain. Oil production in the contiguous States has been declining since the mid-1970s, and in 1989 Alaskan production declined for the first time since 1981. The low price of oil over the past 4 years has contributed to this decline.

Exploration was also affected by the low price of crude. According to the EIA, exploration indicators showed a dramatic drop in the number of seismic crews, operating rigs, and completed wells.[3] More oil will be discovered in the United States, but it is very unlikely that new discoveries will reverse the long-term decline.

This decline in production translates into a greater dependence on oil imports. In 1989, petroleum net imports reached 41 percent of total consumption. Saudi Arabia, Canada, Venezuela, and Nigeria are our biggest suppliers. These and other oil producing countries have used less than 35 percent of their resources. According to a recent resource assessment, the Middle East has the majority of the identified reserves for the world, enough oil to continue production for 124 years. It is likely that the United States will continue to import Middle Eastern oil for many decades.[4]

Since the early 1980s, domestic natural gas production has been declining. New wells have been added, but at a much slower pace than previously. Texas, Louisiana, and Oklahoma produce more than two-thirds of the U.S. total. Most of the natural gas is from onshore and State offshore wells, but about one-fourth is produced from leased Federal offshore areas.[5]

Recent estimates indicate that demand for natural gas will continue to exceed growth in domestic production. In 1989, natural gas imports accounted

[1] U.S. Energy Information Administration, Department of Energy, *Annual Energy Review 1989*, DOE/EIA-0384(89), May 24, 1990, p. 177.

[2] Ibid., p. 178.

[3] Ibid., p. 1.

[4] C.D. Masters et al., "World Resources of Crude Oil, Natural Gas, Natural Bitumen, and Shale Oil," paper presented at World Petroleum Congress, Houston, TX, 1987; in Oak Ridge National Laboratory, *Energy Technology R&D: What Could Make a Difference?* "Supply Technology," ORNL-6541/V2/P2, vol. 2, Part 2, December 1989, pp. 2-4.

[5] U.S. Energy Information Administration, op. cit., footnote 1, p. 158.

## Table 3-l-Major Technologies for Energy Supply and Conversion

| Technology | Availability | Comments |
|---|---|---|
| *Oil* | | |
| Deepwater/arctic technologies | C,R | Existing technologies that are promising for deepwater areas include guyed and bouyant towers, tension leg platforms, and subsea production units. Advances in material and structural design critical; innovative maintenance and repair technologies important. |
| Enhanced oil recovery techniques<br>—thermal recovery<br>-miscible flooding<br>-chemical flooding | C,R | Widely adopted over the past two decades. |
| *Oil shale and tar sands*<br>-Surface retorting<br>—Modified in situ | C,N | Uneconomic at present oil prices. |
| *Natural gas* | | |
| —Hydraulic fracturing | C | Very complex process; not well understood although successful for some formations. Key to unlocking unconventional gas reserves. |
| Coal | | |
| —Atmospheric fluidized-bed combustion (AFBC)<br>—Pressurized fluidized-bed combustion (PFBC) | N,R | Small-scale units commercial. Utility-scale AFBC in demonstration stage. PFBC is less well developed; pilot-plant stage. |
| —Integrated gasification combined cycle (IGCC) | N | Demonstration stage. Primary advantages are its low emissions and high fuel efficiency. |
| —flue-gas desulfurization (FGD) | c | Mature technology; considerable environmental advantages. |
| -Sorbent injection | C,N | Commercially available control technology. Can remove nitrogen oxides up to 90 percent. |
| -Staged combustion | R | Has potential to remove up to 80 percent of nitrogen oxides. |
| *Nuclear* | | |
| —Advanced light water reactor | c | Incorporates safety and reliability features that could solve past problems; public acceptance uncertain. |
| —Modular high-temperature gas reactor (MHTGR) | N,R | Improvements to familiar technology; incorporates passive safety features; design of modular reactor completed. |
| —Power Reactor Inherently Safe Module (PRISM) | R | Conceptual designs expected to be completed this year. |
| *Electricity* | | |
| —Combined cycle (CC) | c | Conventional CC is a mature technology; advanced CC is in demonstration stage. |
| —Intercooling Steam Injected Gas Turbine (ISTIG) | N | Pilot-plant stage. |
| —Fuel cells | R | Several types being developed. Fuels cells that use phosphoric acid as electrolytes are in demonstration stage. Molten carbonate and solid oxide are alternative electrolytes that are less developed. Late 1990s availability, at the earliest. |
| —Magnetohydrodynamics (MHD) | R | Difficult technical problems remain, especially for coal-fired MHD systems. |
| —Advanced batteries | R | Research and development needed in utility-scale batteries to improve lifetime cycles, operations maintenance costs. Promising batteries are advanced lead, zinc-chloride and high-temperature sodium-sulfur.. |
| —Compressed air energy storage (CAES) | c | First U.S. plant (11O-MW) to begin operation in 1991; owned and operated by Alabama Electric Cooperative, Inc. |
| *Biomass* | | |
| —Thermal use | c | Use of biomass by utilities is usually uneconomical and impractical. |
| -Gasification | c | Anaerobic digestion used commercially when biomass rests are low enough. Methane production from biomass not yet competitive with conventional natural gas unless other factors considered. |
| —Production of biofuels | C,R | Research being done on wood-to-ethanol/methanol conversion processes. Could be demonstrated by 2000. |
| *Geothermal*<br>—Dual flash<br>—Binary cycle | N | Single-flash system used extensively. Little commercial experience with dualflash. Binary cycle system may be availabfe in 40-to50-MWe range by 1995. |
| *Solar thermal electric* | | |
| -Central receiver | R | Several plants built, including one in California; 30-MW plant in Jordan is major project today. |
| —Parabolic solar trough | c | Several commercial plants built in California; additional capacity planned appears to be marketable. |
| —Parabolic dishes | N,R | Testing being conducted in new materials and engines such as free-piston sterling engine. |
| *Photovoltaic*<br>-Concentrator system<br>—Flat-plate collector | R | Improvements needed to make photovoltaic cells economic in the bulk power market advances in microelectronics and semiconductors can make photovoltaics competitive with conventional power by 2010. |
| *Wind power* | c | Renewable source closest to achieving economic competitiveness in the bulk power market. Current average cost is 8 cents/kWh. |
| *Ocean thermal energy conversion* (OTEC) | R | Research focused on closed and open cycle systems: no commercial plants designed. May be competitive in 10 years for small islands where direct-generation power is used. Use of OTEC domestically for electric power is unlikely except for coastal areas around Gulf of Mexico and Hawaii. |

KEY: C = commercial; N = nearly commercial; R = research and development needed.

SOURCE: Office of Technology Assessment, 1991.

Table 3-2--Production of Energy bySource (quadrillion Btu).

| Year | Coal | Natural gas[a] | Crude oil[b] | Natural gas plant liquids | Hydroelectric power[c] | Nuclear electric power[d] | Other | Total |
|---|---|---|---|---|---|---|---|---|
| 1970 | 14.61 | 21.67 | 20.40 | 2.51 | 2.63 | 0.24 | 0.01 | 62.07 |
| 1971 | 13.19 | 22.28 | 20.03 | 2.54 | 2.82 | 0.41 | 0.01 | 61.29 |
| 1972 | 14.09 | 22.21 | 20.04 | 2.60 | 2.86 | 0.58 | 0.03 | 62.42 |
| 1973 | 13.99 | 22.19 | 19.49 | 2.57 | 2.86 | 0.91 | 0.05 | 62.06 |
| 1974 | 14.07 | 21.21 | 18.57 | 2.47 | 3.18 | 1.27 | 0.06 | 60.84 |
| 1975 | 14.99 | 19.64 | 17.73 | 2.37 | 3.15 | 1.90 | 0.07 | 59.86 |
| 1976 | 15.65 | 19.48 | 17.26 | 2.33 | 2.98 | 2.11 | 0.08 | 59.89 |
| 1977 | 15.76 | 19.57 | 17.45 | 2.33 | 2.33 | 2.70 | 0.08 | 60.22 |
| 1978 | 14.91 | 19.49 | 18.43 | 2.25 | 2.94 | 3.02 | 0.07 | 61.10 |
| 1979 | 17.54 | 20.08 | 18.10 | 2.29 | 2.93 | 2.78 | 0.09 | 63.80 |
| 1980 | 18.60 | 19.91 | 18.25 | 2.25 | 2.90 | 2.74 | 0.11 | 64.76 |
| 1981 | 18.38 | 19.70 | 18.15 | 2.31 | 2.76 | 3.01 | 0.13 | 64.42 |
| 1982 | 18.64 | 18.25 | 18.31 | 2.19 | 3.27 | 3.13 | 0.11 | 63.90 |
| 1983 | 17.25 | 16.53 | 18.39 | 2.18 | 3.53 | 3.20 | 0.13 | 61.21 |
| 1984 | 19.72 | 17.93 | 18.85 | 2.27 | 3.35 | 3.55 | 0.17 | 65.85 |
| 1985 | 19.33 | 16.91 | 18.99 | 2.24 | 2.94 | 4.15 | 0.21 | 64.77 |
| 1986 | 19.51 | 16.47 | 18.38 | 2.15 | 3.02 | 4.47 | 0.23 | 64.23 |
| 1987 | 20.14 | 17.05 | 17.67 | 2.22 | 2.59 | 4.91 | 0.24 | 64.82 |
| 1988 | 20.74 | 17.49 | 17.28 | 2.26 | 2.31 | 5.66 | 0.24 | 65.97 |
| 1989 | 21.35 | 17.78 | 16.12 | 2.16 | 2.77 | 5.68 | 0.22 | 66.07 |

[a]Dry natural gas.
[b]Includes lease condensate.
[c]Electric utility and industrial generation of hydroelectric power.
[d]Generated by electric utilities
[e]*Other is electricity generated* for distribution from wood, *waste,geothermal,wind, photovoltaic, and solar thermal energy.*

NOTE: Sumofcomponents maynotequal total duetoindependent rounding.

SOURCE: U.S. Energy Information Administration, *Annual Energy Review* 1989, DOE/EIA-0384(89), May 24, 1990; and *Monthly Energy Review April* 1991, DOE/EIA-0035(91/04), Apr. 26, 1991, p. 19.

for almost 7 percent of total gas consumption and are expected to increase in the near term. Canada is our major supplier with Algeria providing smaller amounts. The United States also exports small amounts of gas to Japan.[6]

Electricity has steadily increased its share of the total U.S. energy market from 24.4 percent in 1970 to about 36 percent in 1989. In the past 15 years, the electric utility industry has had financial problems due to excess capacity, as powerplants ordered in the 1970s came online and demand growth fell below industry's expectations. Excess capacity is disappearing as demand grows and local shortages may occur, but overall, resources appear to remain adequate. In fact, according to the North American Electric Reliability Council, most regions have more than enough capacity to meet their increasing needs for several years. This projection rests on two assumptions: 1) that electricity use increases at projected rates, and 2) that existing and planned capacity is available as projected.

Since the mid- 1970s, coal- and nuclear-powered generation have displaced substantial quantities of petroleum and natural gas. Growth in oil and gas use began to slow in the 1970s, and consumption decreased during the first half of the 1980s. In 1989, coal accounted for 56 percent of electric utility consumption, compared to 9 percent for natural gas and 6 percent for petroleum.[7]

Nuclear power accounted for about 19 percent of electricity generation in 1989,[8] and preliminary U.S. Department of Energy (DOE) estimates indicate that nuclear power's share increased by 1 percent in 1990.[9] Nuclear power's contribution to electric power generation has increased steadily since the mid- 1960s. The number of operable nuclear generating units reached an all-time high (1 12) in 1989, but only a few of the planned new units remain under

[6]Ibid.
[7]Ibid., p. 203.
[8]Ibid., p. 219.
[9]U.S. Energy Information Administration, *Electric Power Monthly March 1991*, DOE/EIA-0226(91/03), March 1991, p. 23.

construction, and no additional units are planned.[10] Uncertainty about electricity demand, increases in construction costs and rising interest rates, and questions about nuclear safety and waste disposal have contributed to the decline of nuclear power as a supply option.

Renewable energy resources account for a small share of total energy supplies today. Hydroelectric power is by far the greatest contributor, accounting for about 2.7 quads (quadrillion British thermal units) in 1989.[11] However, concerns about the environment and our dependence on imported oil have renewed interest in alternative sources of energy. The conversion of solar energy to electricity, using either photovoltaics or thermal-electric technologies, offers an exciting but not yet competitive resource under traditional economic terms. Continued improvements in performance and cost of electric power from wind turbines and geothermal technologies are also expected.

## TECHNOLOGICAL OPPORTUNITIES FOR IMPROVING FOSSIL FUEL SUPPLIES

Oil, natural gas, and coal are the primary energy sources in the United States because they are convenient and economical. They are expected to remain so in the foreseeable future. Technologies that can extend the production of oil and gas or replace them with equivalent fuels from coal are the focus of this section. In addition, new technologies for improving the combustion of coal are examined.

### *Petroleum*

#### Conventional Production Technology

Primary conventional techniques utilize natural forces to coax the oil to the surface. Pressurized water can be used to displace oil, or oil can be drained downward from a high elevation in a reservoir to wells at lower elevations. However, most of the reservoir's oil remains in place. Techniques can be used to augment natural forces. These include injecting fluids (commonly, natural gas) into an oil reservoir. This is commonly known as secondary recovery. Conventional primary and secondary recovery technologies can recover about one-third of the oil in place.

Drilling techniques also can be used to improve recovery. Geologically targeted infill drilling, for example, involves drilling reservoirs at closer than normal intervals. Each reservoir has to be geologically targeted in order for this recovery method to be economical. The Oak Ridge National Laboratory (ORNL) estimated that the geologically targeted infill-drilling technique will recover an additional 8 percent of the original oil in place.[12]

In addition, the use of horizontal drilling in offshore production is rapidly expanding. The advantages of using horizontal drilling are improved recovery, better drainage, and the ability to drill and complete several wells from one offshore production platform.[13]

#### Deepwater Technologies[14]

Most of the undiscovered oil and gas reserves in the United States are expected to be found offshore or onshore Alaska. The Alaska Outer Continental Shelf (OCS) region includes about 1,300 million acres. The U.S. Department of the Interior has leased 8.2 million acres since 1976.[15]

The technologies to explore and produce the oil and gas in these remote locations have developed, and will probably continue to develop, in an evolutionary fashion. The oil and gas industry moved its onshore technology offshore-frost onto piers, then onto seabed-bound platforms, and finally onto floating vessels as it ventured into deeper water. Technological advances continue to be made as new deepwater fields are discovered. From the mid-1960s to mid-1980s, technological developments improved deepwater exploratory drilling from a maximum depth of 632 to 6,952 feet.

---

[10] U.S. Energy Information Administration, op. cit., footnote 1, p. 219.

[11] Ibid., p. 7.

[12] Oak Ridge National Laboratory, op. cit., footnote 4, p. 12.

[13] Ibid.

[14] Most of this discussion is based on the OTA report *Oil and Gas Technologies for the Arctic and Deepwater*, OTA-0-270 (Washington, DC: U.S. Government Printing Office, May 1985). The reader is referred to this report for a more indepth discussion of the technological, economic, and environmental factors that affect exploration and development of energy resources in the Arctic regions.

[15] U.S. Department of the Interior, Minerals Management Service, *Alaska Update: September 1988-January 1990*, MMS90-0012, 1990, p. 1.

Thus far, nearly all offshore fields have been developed using freed-leg production platforms. These platforms can probably be designed for water depths of 1,575 feet or more. However, as depths increase, structures become larger, more substantial, and thus more expensive. The cost and size of these platforms may limit their application to greater depths.

Existing technologies that are promising for deepwater areas include guyed and buoyant towers, tension leg platforms, and subsea production units. (See figure 3-l.) All but the subsea units are flexible structures that ''give way" under wind, wave, and current forces. Current technologies can be extended to depths of about 8,000 feet without the need for major breakthroughs.

The guyed tower is a tall, slender structure that requires less steel than a freed-leg platform. Guy lines or anchor lines are used to resist lateral forces and to hold the structure in a nearly vertical position. Exxon installed the first guyed tower in the Gulf of Mexico. The buoyant tower is also a tall, slender structure. Large buoyancy tanks, rather than guy lines, maintain the tower's vertical position.

A tension leg platform is a floating platform that is freed by vertical tension legs to foundation templates on the ocean floor. Buoyancy is provided by pontoons. Bouyancy in excess of the platform weight maintains tension on the legs. This technology can be used economically in deep water. Its primary disadvantages are the operational complexity relative to fixed platforms and its limited deck load capacity. The first tension leg platform was installed in 1984 by Conoco in the North Sea.

Subsea production systems are also used to develop deepwater fields. Wells are drilled from a floating rig and completed on the seafloor. There are two types of subsea production systems: wet or dry. The wet system is relatively insensitive to water depth and can be installed in deep water in much the same manner as in shallow water. It is limited by the depth capability of the floating drilling unit. In the dry system, the well head is housed in a dry, atmospheric chamber on the sea floor. Flowline connection and maintenance work can be done by workers inside the chamber. Personnel are transported to and from the chamber in a diving bell. Most subsea production systems are single well. The oil is produced through a flowline to shore or to a freed or floating platform. One of the limitations of this system is the need to have surface facilities to process and transport the oil.

A number of production-related technologies are crucial to the development of deepwater areas. Advances in materials and structural design and foundation engineering are critical. Innovative techniques for the installation, maintenance, and repair of platforms and pipelines are also important. Deepwater pipeline systems will involve adaption from conventional pipelaying techniques, but new approaches will have to be developed to overcome problems, e.g., buckling by long unsupported span lengths, higher strain levels, and severe seas. Support operations, e.g., diving and navigation, will be increasingly important. Because human diving capability is limited, manned vehicles and remote-controlled unmanned vehicles will be increasingly used for these purposes.

### Arctic Production[16]

Offshore exploration of the Arctic region began in the mid- 1970s. Since then, the pace of activity and technological advances have increased significantly. See table 3-3 for the status of North Slope exploration and production projects.

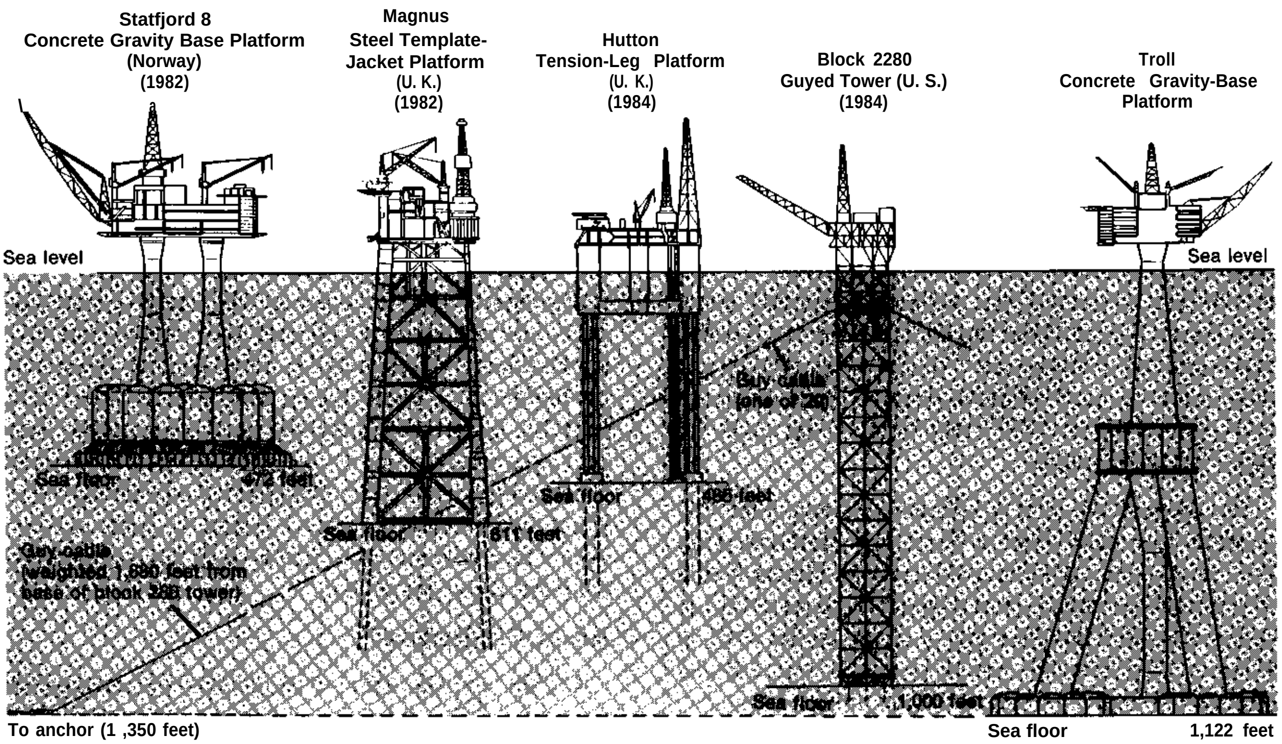
Because of the severe environment, oil and gas development in the Arctic region is a major technological challenge. Production systems must withstand exposure to severe and corrosive conditions for the life of the oil fields, which is usually 20 years or more. Ice conditions, including duration, thickness, and movement, are perhaps the most critical of the environmental considerations.

The type of exploratory drilling rig and the technology needed for field development are determined by site and environmental conditions. Most offshore exploratory drilling has been done from manmade (gravel) islands. However, gravel islands could be prohibitively expensive in water deeper than 50 to 60 feet. The alternatives are steel and concrete structures built as caissons or complete bottom-mounted units. There are many designs for these structures, including conical shapes to reduce ice forces.

Additional research is needed on ice properties, movements, and forces under a range of conditions

[16] Arctic is defined as the Beaufort, Chukchi, and Bering Seas north of the Aleutian Islands.

**Figure 3-1—Production Platform Technologies for Frontier Areas**




SOURCE: U.S. Congress, Office of Technology Assessment, *Oil and Gas Technologies for the Arctic* and *Deepwater,* OTA-O-270 (Washington, DC: U.S. Government Printing Office, May 1985), figure 3-3.

that are likely to be encountered. Increased surveillance from satellites and aircraft is needed to provide real-time data. These data are important for structural design purposes, logistics, and tanker transportation design and planning. In addition, more information is needed on oceanographic and meteorological processes and seismicity.

## Exploration Technology

Many experts believe that most of the United States' low-cost oil has been discovered and produced. Increasingly, new production must come from oil finds in hostile, expensive frontier areas or from high-technology, high-cost oil recovery operations. Improvements in technologies that measure gravity and magnetism and record seismic informaion are critical to selecting favorable drill sites. Seismography, which was originally developed to record earthquakes, is now used as a prospecting tool. A seismograph provides the only direct way of acquiring subsurface structural information without drilling wells. The petroleum industry has recently developed new recording instruments called seismometer group recorders.

Another improvement, the borehole gravimeter, can measure rock densities as far as several hundred feet away from the borehole. The borehole gravimeter can also be used to indicate rock content—whether it is oil, dry gas, or water. This information is key to understanding structural conditions.

Continual advances in computers and electronic equipment have made it possible to analyze larger geographical areas more easily and interpret data more accurately.

## Enhanced Oil Recovery

As noted earlier, conventional recovery techniques recover on average about 34 percent of the oil in place. Improvements can be made by using enhanced oil recovery techniques. The techniques most commonly used are thermal recovery, miscible flooding, and chemical flooding. They have been widely adopted over the past two decades. The

## Table 3-3-Status of Alaska State Coastal Exploration, Development, and Production Projects

| Unit/field/ prospect | Desig- nated operator | Lease sale | Sale date | Reserves in place | Reserves recoverable | Explora- tory drilling | Delin- eation | Devel- opment | Primary production | Secondary production | Tertiary production | Status as of December 1989 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Colville Delta (Texaco) | Texaco | | | N/A | N/A | X | | | | | | No activity. |
| Duck Island Unit (Endicott) | BP Exxon | Joint Federal-State lease Sale | 09/10/69 12112179 | 1,000 MMBO | 0,8 Tcf 375 MMBO | X | X | X | X | | | Maintain production at 100,000 bpd. |
| Gwydyr Bay Unit | ARCO | State Sale 23 | 09/10/69 | | 30-60 MMBO | X | X | | | | | Total of 12 wells. Renewed interest in prospect by Vaughn Petroleum (et al.) in 1987. Drilled two wells both P&A. Reduced reserve estimates and wait for higher oil price. Conoco resigns as operator. |
| Kaktovik Prospect (KIC well) | Chevron | Negotiated with Arctic Slope Regional Corp. | 11/83 | N/A | N/A | X | | | | | | Tight hole. |
| Kuparuk Unit | ARCO | State sale 14 | 07/14/65 | 4,400 MMBO | 070 MMBO | X | X | X | X | X | X | Steady production at 260,000 bpd; 39 percent oil field depleted. |
| Lisburne Field | ARCO | State sale 14 | 01/24/67 | 3,000 MMBO | 165 MMBO | X | X | X | X | X | | Recoverable reserve estimates reduced 50 percent. |
| Mine Point Unit | Conoco | State sale 14 | 07/14/65 | | 60 MMBO | X | X | X | X | | | Shutdown since January 1987; Conoco received drilling permits. Plans to begin production again. |
| Niakuk Prospect | BP | State sales 14 and 18 | 07115165 01/24167 | 145 MMBO 88 Bcf | 58 MMBO 35 Bcf | X | X | X | | | | Army Corps of Engineers rescinded earlier causeway denial. BP must submit additional data on causeway, |
| North Star | Amerada Hess | | | N/A | 150 MMBO | X | X | X | | | | Initial stages of development; proposed unit agreement. |
| Pt. McIntyre | ARCO | State sale 14 | 07114165 | N/A | 300 MMBO | X | X | | | | | Drilled three wells in 1988 and 1989 with approved drilling permits for three more. |
| Point Thomson Unit | Exxon | State sale 18 | 01/24/67 | | 350 MMBO 5 Tcf | X | X | | | | | Will drill another delineation wellspring 1990. |
| Prudhoe Bay Unit | ARCO/BP | State sale 13, sale 14, sale 18 | 12/09/64 07/14/65 01/24/67 | 23.5 BBO | 9.4 BBO 29 Tcf | X | X | X | X | X | X | Enhanced recovery techniques and sale good reservoir management will keep production at 1.5 MMbpd through 1969 with slower production decline now anticipated. Eileen West End Field started producing in June 1988. Peak production will be 60,000 to 70,000 bpd in 1990 from 76 wells. |
| UGNU Field in Kuparuk/ Prudhoe/Mine | ARCO | State sale 13, sale 14, sale 18 | 12/09/64 07/14/65 01/24/67 | 6-11 BBO | 0 | X | | | | | | Drilled production test well April 1989. Loose sandstone reservoir and low American Petroleum Institute gravity present major technological hurdles. |
| West Sak Field | ARCO | BF(SM) | 12/12/79 | 15-25 BBO | 750 MMBO | X | X | | | | | ARCO filed application with ACOE to build gravel pads. Subsequently, delayed citing economic impact. |

KEY: ACOE = Army Corps of Engineers; BBO = billion barrels of oil; Bcf = billion cubic feet; bpd = barrels per day; MMBO = million barrels of oil; Tcf - trillion cubic feet.

SOURCE: U.S. Department of the Interior, *Minerals Management Service Alaska Update,* September 1988-January 1990, MMS90-0012,1990, p. 33.

use of enhanced recovery methods is dependent on the characteristics and location of the field.

*Thermal Recovery Process*—The viscosity of crude oil varies considerably. Some crudes flow like road tar, others as readily as water. High viscosity makes oil difficult to recover with primary or secondary production techniques. Viscosity of most oils decreases as the temperature increases. The purpose of thermal oil recovery processes is to heat the oil to make it flow more easily. The oil can be heated by injecting hot water, steam, or hot gases into a well.

More than 90 percent of thermal recovery projects in the United States are in California, where heavy crudes are common. According to ORNL, total oil recovery using primary pumping and thermal recovery can exceed 50 percent of the available oil in the field. The cost of the thermal process can range from $3 to $18 per barrel.[17]

*Miscible Gas Flooding*—Another common approach to enhanced oil recovery is miscible gas flooding. Miscible gas, which is usually either a hydrocarbon mixture (natural gas) or carbon dioxide ($CO_2$), is injected into a well. Inert gases, such as nitrogen, can also be used for gas flooding. The gases act as solvents, forming a single oil-like liquid that can flow through a reservoir to other wells more easily than the original crude. Hydrocarbon gas flooding is economical when there is a large supply of available natural gas. For example, hydrocarbon flooding accounts for about 10 percent of oil production in Alberta, Canada, where there is a large supply of natural gas associated with the production of oil. Also, unused natural gas can be injected back into the field to increase oil yield. This is being done in the Alaskan North Slope fields.[18]

In the contiguous United States, the use of hydrocarbon flooding is less common because of the lower availability of and greater demand for natural gas. $CO_2$ flooding is more common. $CO_2$ is injected under such high pressure that it becomes like a liquid which is miscible with oil. More than 60 percent of gas flooding projects in the United States use carbon dioxide. The cost of $CO_2$ flooding ranges from about $10 to $23 per barrel.[19]

*Chemical Flooding*—A number of other processes involve injecting chemicals (e.g., surfactants and polymers) into the water-flooded field to alter the properties of the liquids. Polymers are added to the field to increase the viscosity of water. Surfactants are used to alter the surface properties of the oil-water and permit the removal of oil from capillary regions of a field. Chemical flooding processes are not yet well developed. Moreover, oil yields from these processes are difficult to predict. The cost of polymer flooding can be low but so too can the yield of additional oil. One estimate of the cost of surfactant flooding is between $15 and $30 per barrel. In addition, the degradation of chemicals can be a problem.[20]

Microbial enhanced oil recovery is a variation of chemical flooding. Microorganisms, which are introduced into a reservoir, produce detergent-like materials that would perform much the same function as polymers and surfactants. This technology is not well developed and a number of uncertainties remain. For example, any bacteria developed would need to be monitored for potential environmental impacts.

Although enhanced oil recovery is a particularly attractive technology for extending known oil supplies, it is hampered by a number of uncertainties. These include the inability to predict the amount of oil that can be recovered and the difficulty in characterizing the field. These uncertainties may limit the use of enhanced recovery techniques to those projects where improvements in recovered oil are sufficient enough to take the risk. Current research and development (R&D) programs are focusing on understanding the physical processes taking place in an enhanced recovery operation and quantitatively examining the structure and flow patterns of the field.

### Oil Shale and Tar Sands Production Technologies

Oil shale is the second most abundant fossil energy resource in the United States. North American oil shale resources in place are estimated at 5,600 billion barrels. How much is recoverable is not

---

17O* Ridge National Laboratory, op. cit., footnote 4, pp. 12-13.

18Ibid., p. 13.

19Ibid.

20Ibid.

known.[21] At present oil prices, recovery of these resources is uneconomic.

Oil shale consists of a porous sandstone that is embedded with a heavy hydrocarbon known as kerogen. Because the kerogen already contains hydrogen, a liquid shale oil can be produced from the oil shale simply by heating the shale to break the kerogen down into smaller molecules. This can be accomplished by a surface retort process, a modified in situ process, or a so-called true in situ process. Liquid shale oil can be upgraded relatively easily to crude oil.

In the surface retort method, oil shale is mined and placed in a metal reactor where it is heated to produce the oil. This method is best suited to thick shale seams near the surface. In the modified in situ process, an underground cavern is excavated and an explosive charge detonated to fill the cavern with broken shale rubble. Part of the shale is ignited to produce the heat needed to crack the kerogen. Liquid shale oil flows to the bottom of the cavern and is pumped to the surface. The modified in situ method is used in thick shale seams deep underground. In the true in situ process, holes are bored into the shale and explosive charges are ignited in a particular sequence to break up the shale. The rubble is then ignited underground, producing the heat needed to convert the kerogens to shale oil. The true in situ method is best suited to thin shale seams near the surface.

The surface retort method requires the mining and disposal of larger volumes of shale than the modified in situ method. The true in situ method requires very little mining. However, high oil yields of relatively uniform quality are difficult to achieve using the modified and true in situ methods. This is due to difficulties in controlling underground combustion and ensuring that the heat is efficiently transferred to the shale.

Since 1980, Unocal has constructed a commercial-size oil shale project in Colorado. The underground mine produces 13,500 tons of crushed ore per day, and the retorting complex is designed to produce 10,000 barrels of oil per day. In 1988, the complex operated for several months at 5,000 to 6,000 barrels per day at a cost of $45/barrel.[22]

Tar sands resources in North America are estimated at315 billion barrels, most located in Canada. Oil from tar sands is being commercially produced at the huge Athabasca deposit in Alberta, Canada. In the United States and Canada, much of the resource is not minable at the surface and will have to be produced using in situ extraction technologies. R&D efforts have focused on the chemical and physical properties of tar sands and the physics of mobilizing and extracting the bitumen constituents.[23]

## *Natural Gas*[24]

### Conventional Gas Production

The way in which gas is produced depends on the properties of the reservoir rock and whether the gas occurs by itself or in association with oil. Hydrocarbons in the reservoir rock migrate to the producing well because of the pressure differential between the reservoir and the well. How readily this migration occurs is a function of the pressure of the reservoir and the permeability of the reservoir rock. When the reservoir rock is of low permeability, the rock may be artificially fractured to form pathways to the wellbore. This is accomplished either with explosives or by hydraulic means, pumping a pressurized fluid into the well.

Production can continue as long as there is adequate pressure in the reservoir to propel the hydrocarbons toward the producing well. If gas is the only propellant, the reservoir pressure decreases as the gas is extracted and is eventually no longer sufficient to force the hydrocarbons toward the well. In a water-driven reservoir, water displaces the hydrocarbons from the pores of the reservoir rock, maintaining reservoir pressure during production and improving the recoverability of the hydrocarbons. In most reservoirs, gas recovery is high compared to oil recovery. A recovery value of 80 percent is typical.

[21] Ibid., p. 9.

'Ibid., pp. 18-19.

[23] Ibid.

[24] Much of the information in this section is drawn from the OTA report *U.S. Natural Gas Availability: Gas Supply Through the Year 2000*, OTA-E-245 (Washington, DC: U.S. Government Printing Office, February 1985). The reader is referred to this report for a more indepth analysis of conventional and unconventional gas supplies.

When gas occurs in association with oil, it can be reinfected into the reservoir to maintain pressure for maximum oil recovery. Gas is also reinfected when there are no pipeline facilities available to transport it to market.

### Enhanced Gas Recovery

At some reservoirs, recovery efficiencies are much lower than 80 percent. For example, recovery rates for water-driven reservoirs found along the Texas and Louisiana Gulf Coast are known to be 50 percent or less. These poor recovery rates result from water encroachment and the subsequent trapping of gas in water-driven reservoirs and from uncertainties about the characteristics of the reservoir. A better understanding of gas field characteristics and improvements in drilling and production technologies would increase recovery efficiencies.[25]

### Unconventional Gas Production

Unconventional @s includes tight sands, Devonian shale, methane from coal, and geopressured brine. The Devonian shales and methane from coal are the best understood of the unconventional resources and appear to have the most near-term potential for contributing to supply. Estimates of total recoverable unconventional gas resources are 600 trillion cubic feet (Tcf) for tight sands, 400 Tcf for Devonian shale, and 400 Tcf for coal seams.[2G] If natural gas is to play a significant role in reducing $C0_2$ emissions, it will be important to find ways of recovering ‘‘unconventional’ gas resources.

Tight gas is natural gas that is found in formations of sandstone, siltstone, silty shale, and limestone. These formations are characterized by their very low permeability. There are two distinct types of tight formations: blanket formations, which extend laterally over large areas, and lenticular formations, which consist of many small discrete reservoirs, often shaped like lenses. Figure 3-2 shows the main tight gas-bearing basins in the contiguous United States.

Over the past several decades, rising gas prices, tax policies, and improvements in production technology have encouraged gas producers to exploit more lower permeability formations. Because of poor flow characteristics of reservoir rock in tight formations, economically recoverable gas can be achieved only by increasing permeability by fracturing the rock surrounding the wellbore. This fracturing is most commonly hydraulic, which involves pumping a fluid under high pressure into the well until the rock breaks down. Sand or other materials are added to the fluid to serve as wedges to prevent the fractures from closing.

The fracturing process in tight formations is very complex and not well understood. It is difficult to tell what a fracture will do or what it has done even after the well is producing or proved unproductive. Despite these uncertainties, fracturing has been successful, at least for the blanket formations. Large-scale fracturing of lenticular formations has not been very successful. Lenticular formation developers have tended to use shorter, less expensive fracturing treatments, which may imply lower gas recovery.

Devonian shale gas is produced from shales formed about 350 million years ago--during the Devonian period. Devonian shales occur primarily in the Appalachian region, Illinois, and Michigan. The shale gas occurs as free gas in the fractures and pores of the shale and also as gas physically bound to the shale (adsorbed gas).

As with tight sands, Devonian shale production depends on well stimulation to overcome the naturally low permeability of the reservoir and open up pathways for the gas to flow to the wellbore. Unlike tight sands, however, successful Devonian gas production depends on the well intersecting a natural fracture network, either directly or through an induced fracture.

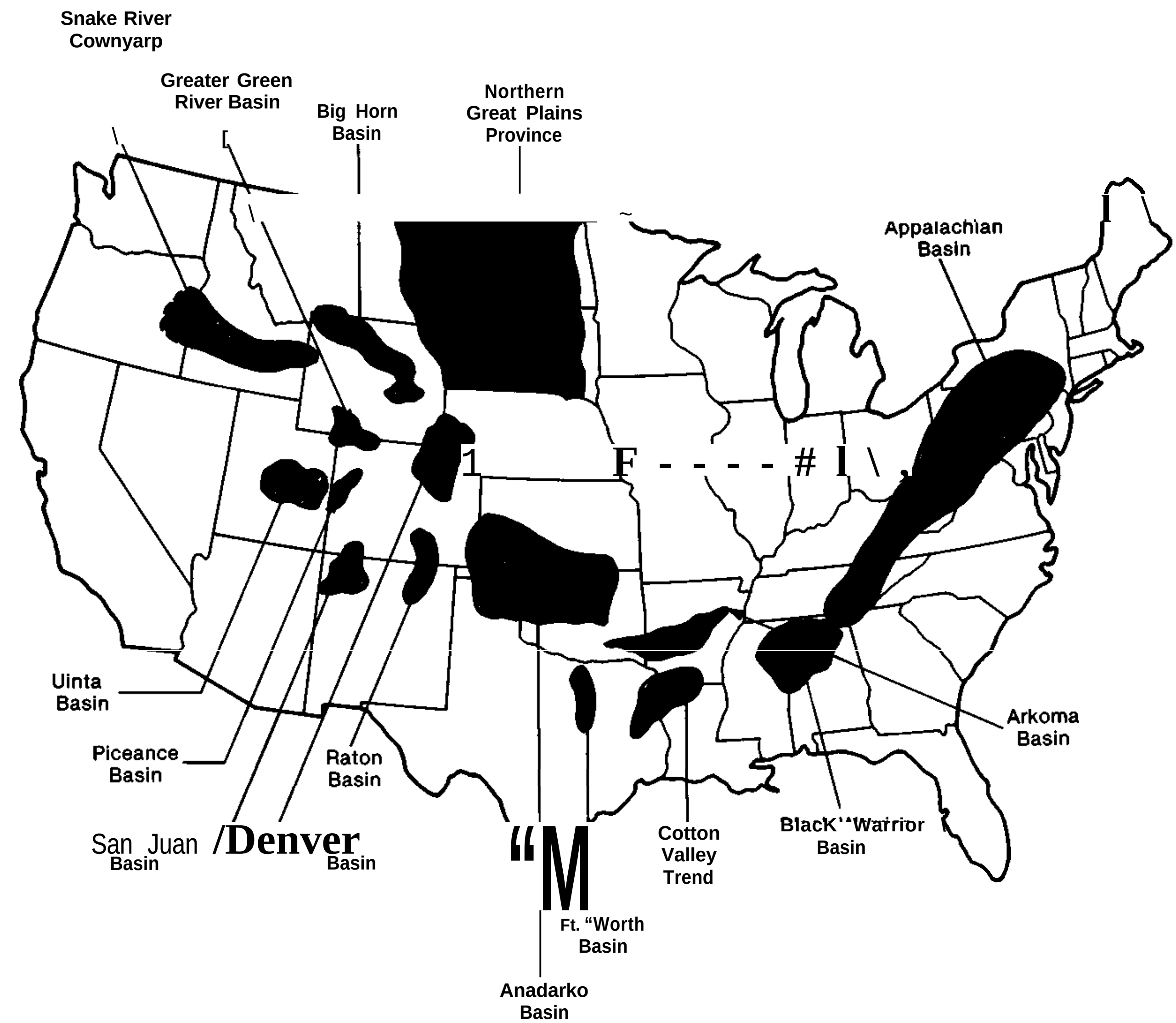
Stimulation by the use of explosives has been prevalent in production history, and more sophisticated explosive techniques may be promising for future development. Also, new fracturing fluids that avoid formation damage have been used for Devonian shale development. These include gas-in-water emulsions, nitrogen, and liquid carbon dioxide. The gas-in-water emulsions have been popular, but nitrogen has also grown in use for shallow wells because it does not cause formation damage.

Methane from coal is a byproduct of the coal formation process that is trapped in the coal seams. Methane is found in all coal seams, although its

[25]Oak Ridge National Laboratory, op. Cit., footnOte 4, p. 17.

[26]Ibid., p. 8.

**Figure 3-2—Location of Principal Tight Formation Basins**




SOURCE: U.S. Congress, Office of Technology Assessment, *U.S. Natural Gas Availability, OTA-E-245* (Washington, DC: U.S. Government Printing Office, February 19S5), figure 26.

amount per unit volume or weight of coal tends to be proportional to the carbon content of the coal. Anthracite and bituminous coal have high carbon content and higher gas content. Methane content also increases with depth.

Because coal in itself is essentially impermeable, methane production depends on intersecting the natural fracture network to provide pathways for the gas to flow to the well. A second condition of economic production of methane is to promote the resorption of the gas from the coal into the fracture system by reducing the pressure in the fractures. Many coal seams contain water and thus the reservoir pressure is partially a hydrostatic pressure caused by groundwater. Reducing pressure usually involves pumping water out of the seam. The water removal also increases the relative permeability of the gas in the fracture network, allowing more gas to flow to the wellbore. The effective recovery of methane may require drilling wells on relatively close spacing and pumping water from them rapidly and simultaneously in order to maximize the pressure drop. This practice of close spacing is in sharp contrast to the wide spacing used in conventional gasfields.

A variety of methods can be used to enable wells to intersect the naturally vertical fracture network. Horizontal wells may be drilled from within a working mine or a specially drilled shaft. The latter method is expensive. Vertically drilled wells maybe slanted toward the horizontal, so as to run parallel to and within the coal seam. Hydraulic fractures can also be used to connect the wellbore to the fracture system.

Other unconventional gas sources include geopressured brines and gas hydrates. Geopressured brines are found deep within the Earth under high pressures and temperatures. They are found primarily in the Gulf Coast region of the United States. In order to produce the gas, the brines are pumped to the surface, the gas is removed, and the brines are disposed. Gas hydrates are an icelike mixture of gas and water, called a clathrate, which forms under certain temperature and pressure conditions often found in water depths greater than 100 feet and under permafrost. The resource is potentially huge and may be augmented by free gas trapped under the impermeable hydrate. It should be noted, however, that gas hydrates are unstable. If they warm just a bit, natural gas is released, contributing to global warming.

Future efforts to recover tight gas, Devonian shale gas and methane from coal will depend on advances in well stimulation technologies and improvements in drilling patterns. Also, additional research is required to understand gas production mechanisms and develop an exploration rationale for identifying attractive drilling sites.

## *Coal*

*Coal* is burned to produce heat, which in turn is used to generate steam for process heat or the production of electricity. The heat may be used directly in industrial processes or space heating. Coal also can be used to effect chemical reactions such as the reduction of iron ore or the production of lime, or indirectly as a source for the production of synthetic gaseous or liquid fuels.

### Direct Combustion

Three major factors influence the way coal is burned: 1) the size of the facility, 2) the environmental standards the facility is required to meet, and 3) the characteristics of the coal to be burned. Most coal is still burned in pulverized coal-fired boiler furnaces. Raw crushed coal is pulverized and blown with air into large furnace cavities, where the cloud of coal dust burns much like a fuel gas. The heat is transferred to water, which boils to generate steam. Over the years, improvements in combustion technology have resulted in larger plants that can operate at higher temperatures and pressures, and therefore higher efficiency. Further efficiency gains are likely to be incremental. In recent years, much of the attention has been focused on reducing emissions.

Conventional technology can meet existing emission standards, especially in large facilities. Emerging technologies are likely to be necessary to meet stricter standards, especially in small- and medium-size facilities. They also may permit substantial gains in efficiency.

Fluidized-bed combustion (FBC) technology[27] offers an emerging alternative. Its basic principle involves the feeding of crushed coal for combustion into a bed of inert ash mixed with limestone or dolomite. The bed is fluidized, or held in suspension, by injecting air through the bottom of the bed at a controlled rate great enough to cause the bed to be agitated much like a boiling fluid. The coal burns within the bed, and the sulfur oxides ($SO_x$) formed during combustion react with the limestone or dolomite to form a dry calcium sulfate. This capability to capture sulfur in situ reduces or eliminates the need for expensive add-on sulfur removal equipment. According to the National Acid Precipitation Assessment Program (NAPAP) report, the FBC system can remove up to 95 percent of sulfur dioxide ($S0_2$) and up to 80 percent of the nitrogen oxide ($NO_x$) emissions.[28]

There are two basic types of fluidized combustors: the atmospheric fluidized-bed combustor (AFBC) and the pressurized fluidized-bed combustor (PFBC). The AFBC operates at atmospheric pressure. Small-scale AFBCs already are used commer-

[27] Much of this section is drawn from the OTA report *New Electric Power* Technologies: *Problems and* prospects *for the 1990s*, OTA-E-246 (Washington, DC: U.S. Government Printing Office, July 1985).

[28] National Acid Precipitation Assessment Program, *NAPAP Report 25*, Technologies *and Other Measures for Controlling Emissions: Performance, Costs and Applicability*, Washington, DC, 1990, p. 6-36.

cially around the world for process heat, space heat, various other industrial applications, and electrical generation.

The PFBC operates at high pressures and therefore can be more compact than the AFBC. It can run exhaust heat through the turbines as well as the steam cycle. The PFBC also may produce more electricity for a given amount of fuel. Despite these potential advantages, the PFBC has more serious technical obstacles to overcome and is less well developed than the AFBC. For example, the corrosion of gas turbine blades is a primary concern for combined cycle PFBCs. In addition, fuel and sorbent feed control may be difficult. The first PFBC/ combined cycle plant began testing in March 1991. The test is expected to last 3 years. The demonstration plant is one of the flagship projects in DOE's Clean Coal Demonstration Program.[29] It is unlikely that more than a few PFBC commercial units could be completed and operating before the end of the century, although the PFBC's longer-term potential is quite promising.

The primary types of AFBCs are bubbling bed and circulating bed. The bubbling-bed AFBC is characterized by low gas velocities through the bed. The result is a bed from which only the smaller particles are entrained with the gas. Conversely, the gas flow velocities through the circulating bed are rapid. Neither technology has been built to produce electricity on a scale (100 to 200 megawatts (MW)) that is attractive to utilities. The bubbling-bed technology is the older of the two and thus greater operating experience in the United States. Also, the bubbling-bed combustor can be readily retrofitted to some conventional boilers. The disadvantages include fuel-feed problems, which are encountered in larger units. With the circulating-bed combustor, the fuel-feed problem may be less serious. However, there is less experience operating circulating-bed AFBCs.

More than 1,000 MW of existing coal-fired capacity are being converted to the AFBC technology. And, about 100 smaller AFBC systems for nonutility applications are either generating power or on order.[30] It is expected that larger utility-scale AFBC units will be ready for use by the mid- 1990s. OTA estimated that the capital cost of a large AFBC is comparable to conventional coal-freed plants equipped with scrubbers—$ 1,260 to $1,580/ kilowatts of electric power output (kWe).

OE has selected two AFBC projects to promote utility use. One project, a circulating fluidized-bed system replaces three small coal-fried boilers with 110 MW of capacity. The second project involves repowering a 250-MW Southwestern Public Service Co. facility. Also, DOE has selected two projects to demonstrate the PFBC technology. The capital cost of a 500-MW PFBC is estimated to be about $1,350 or $1 ,750/kWe for a 200-MW plant.[31]

The integrated gasification combined cycle (IGCC) technology is another alternative to conventional coal-fired plants. In the IGCC process, coal is mixed with air and steam at high temperatures, which causes the coal to gasify to a mixture of hydrogen, carbon monoxide, and hydrogen sulfide, called syngas. The ash is separated and disposed of or used. The sulfur in the coal is converted into hydrogen sulfide, which eventually can be converted to elemental sulfur or some solid waste material. The cleaned gas is burned in a combustion turbine. The hot exhaust gases that exit the combustion turbine generate steam, which can then drive a steam turbine to produce electricity. The name "combined cycle" refers to the use of both gas-fueled combustion and steam turbines in the system.

An IGCC system's major advantages are its very low rate of emissions and its fuel efficiency. It also requires less water than a conventional coal-fired steam plant, and because of the modular design, construction time is shorter. One of the areas where additional research is needed is in fuel gas treatment.

Hot gas cleanup systems remove sulfur and nitrogen compounds and particulate from the fuel gas without cooling and then reheating the gas. These compounds are very abrasive and must be removed to prevent turbine blade and component failure. Existing gas cleanup technology must operate at relatively cool temperatures. Switching from a cold- to hot-gas cleanup system could increase efficiency by 3.6 percent,[32] but many difficult technological problems must be overcome.

29' 'PFBC and a New Era for Coal Arise From Mothballed Plant,'' *Power*, vol. 135, No. 4, April 1991, p. 103.

30*Environmental and Energy Study Conference Special Report*, "Clean Coal Technologies: A Key Clean Air Issue," Oct. 31, 1989, p. 7.

31National Acid Precipitation Assessment Report, op. cit., footnote 28.

32Oak Ridge National Laboratory, op. cit., footnote 4, p. 30.

One of the biggest IGCC demonstration projects is the 1OO-MW Cool Water Plant located in Daggett, California. It has been operating successfully since 1984 and has demonstrated the ability to meet stringent California pollution standards using both low-sulfur Western coal and high-sulfur Eastern coal.

In the Cool Water process, a coal-water mixture is injected into a pressurized, oxygen-fed gasifier. A medium grade fuel is produced. The sulfur in the coal is converted mostly into hydrogen sulfide, and the nitrogen oxide is converted into molecular nitrogen. The hot gases heat the tubes of water, creating steam. The steam is used to drive turbines to produce electricity. The gas and slag are then separated. A sorbent is used to remove 97 to 99 percent of the sulfur from the gas produced from coal.[33] The cleaned gas is burned in a turbine at a low temperature, which reduces $NO_x$ production.

Capital costs for an IGCC system could range from $1,200 to $2,350/kWe (net). For smaller units (250-MW range), costs are expected to be higher, about $1,600 per kWe. The Electric Power Research Institute (EPRI) estimates a plant cost of $1,630/kWe for a 500-MW IGCC. The gas production and purification facilities will account for about 40 percent of total costs. Operating and maintenance costs could range from 6 to 12 mills/kilowatt hour (kWh).[34]

## Technologies for Controlling Emissions[35]

Typically, emissions are reduced by four methods: 1) cleaning coal to reduce sulfur content, 2) switching to low-sulfur coal, 3) using wet flue-gas and 4) using combustion controls for $NO_x$ emissions. According to NAPAP, almost all high-sulfur Eastern coal is cleaned before being burned. Physical coal cleaning reduces $SO_2$ by 10 to 30 percent, but reductions of 50 percent can be achieved.

New advanced coal cleaning technologies can remove up to 65 percent of the sulfur content in coal. These technologies include advanced froth (multistage) flotation, electrostatic separation, and oil agglomeration. The costs of removing $S0_2$ using the multistage flotation process are estimated to range from $131 to $268/metric ton removed, depending on the sulfur content of the feed coal. The costs for the oil agglomeration process ranges from $221 to $472/metric ton removed. These technologies are expected to be commercial by the mid-1990s, but none will be adequate to meet New Source Performance Standards by themselves.

The removal of $S0_2$ from stack gases is termed flue-gas desulfurization (FGD). Devices commonly referred to as scrubbers are used in this process. The function of the scrubber is to bring the flue gases, which contain $SO_2$, into contact with a chemical absorbent, such as lime, limestone, magnesium oxide, etc. FGD technologies are characterized as wet or dry, depending on the state of the reagent as it leaves the absorber.

There are two FGD processes: nonregenerable (throwaway) or regenerable. In the throwaway process, the absorbent and the $SO_2$ react to form a product which is disposed of as sludge or solid. The regenerative process recovers the absorbent in a separate unit for reuse in the scrubber and generally produces a product with market value, such as elemental sulfur or sulfuric acid. A great majority of the FGD processes employed by the utility industry are wet, nonregenerable systems that use limestone or lime.

Wet scrubbing for new plants can remove up to 95 percent of $S0_2$. The technology does not remove $NO_x$, but this can be accomplished by incorporating 1ow-$NO_X$ burners into the design of a new plant. Capital and operating and maintenance costs of the wet limestone FGD technology are dependent on the type of coal burned and the amount of sulfur removed. For example, the capital cost of a 500-MW plant that burns coal with a 0.5-percent sulfur content and removes 70 percent of the sulfur is estimated to be $140/kilowatt (kW). The capital cost is $200/kW for a 200-MW plant that burns 4-percent sulfur coal and is required to remove 90 percent of $S0_2$ emissions.

Another promising technology for reducing $SO_2$ emissions is sorbent injection. This technology has the potential to reduce sulfur dioxide emissions by up to 70 percent. There are two types of sorbent injection: the furnace sorbent injection process and the low-temperature sorbent injection. Both proc-

33*Environmental and Energy Study Conference Report,* Op. cit., footnote 30.

34U.S. Congress, Office of Technology Assessment, op. cit., footnote 27.

35This section is drawn from the *National* Acid *Precipitation* Assessment program *Report 25*, op. cit., footnote 28.

esses should be available in the mid-1990s. The furnace sorbent injection process sprays a calcium-based sorbent material, such as limestone or calcium hydroxide, into the furnace. The heat decomposes the sorbent into lime which captures the $SO_2$ and forms calcium sulfate. The calcium sulfate and fly ash are separated. The low-temperature, or postcombustion, sorbent injection process introduces a calcium-based sorbent into the flue gas, but farther downstream from the combustion zone. Postcombustion sorbent injection is potentially cheaper than furnace sorbent injection and wet flue-gas scrubbing. Sorbent injection retrofits are estimated to cost from $48 to $99/kW, depending on the size and the difficulty of retrofitting the plant. In the United States, several commercial-scale utility projects are now demonstrating furnace sorbent injection.

Currently, $NO_x$ emissions are reduced by modifying the design or operating conditions of combustion equipment. Common techniques include lowering excess combustion air, recirculating the flue gas, and injecting steam or water into the firebox. Reducing excess air reduces the quantity of atmospheric nitrogen available for $NO_x$ formation. Flue-gas recirculation and steam or water injection reduce flame temperature, which is an important factor in decreasing $NO_x$ production. Some of these techniques may reduce energy efficiency because they lower combustion temperatures.

Low $NO_x$ burners are standard features on almost all recently built utility boilers. According to the NAPAP report, low $NO_x$ burners can reduce $NO_x$ by up to 80 percent. The low-$NO_x$ burner technology restricts airflow into the combustion chamber, which lowers combustion temperatures and $NO_x$ formation. In the United States very few retrofits have been performed. Thus, costs are difficult to determine. NAPAP indicated that retrofit capital costs could range from $8 to $34/kW.

Other advanced technologies such as gas reburning and staged combustion could be commercially available in the United States by the mid-1990s. Gas reburning has been used in Japan as a retrofit to oil- and gas-freed plants. In this process, the primary fuel is burned in a secondary combustion zone, which destroys the $NO_x$ produced in the primary combustion zone. Gas reburning has the potential to reduce $NO_x$, emissions by 40 to 75 percent. Several commercial projects have demonstrated fuel reburning using natural gas and coal as the reburning fuel.

Another advanced technology is selective catalytic reduction (SCR). The SCR process is the only commercial control technology that can reduce nitrogen oxides up to 90 percent. SCR is a flue-gas treatment process that reduces $NO_x$ to molecular nitrogen and water by reacting ammonia with $NO_x$ in the presence of a catalyst at temperatures between 300 and 400 degrees Celsius. The catalyst is the primary capital and operating cost component of this technology. SCR can be used in a wide variety of applications, including new and retrofit coal-, oil-, and gas-fired facilities.

Japan and Germany have considerable experience with SCR. U.S. experience with this technology is more recent but expanding. SCR has been used on several gas-freed combustion turbines in California and New Jersey, but has not been applied commercially on boilers that burn high-sulfur and high-alkaline ash content coals. Many boilers in the United States use these types of coal. Before SCR is widely used in this country, concerns about catalyst life, performance, and costs must be addressed.

### Gasification

Gaseous fuels can be synthesized by combining coal with varying amounts of hydrogen and oxygen. Gasification technologies can be used to produce substitute natural gas (SNG); synthesis gas, which can be converted to liquid fuels or used to manufacture chemicals; and to generate electricity in gasification combined cycle systems.

In the 1970s, there was a great deal of interest in coal gasification because of concerns about the adequacy of natural gas supplies. More than 100 coal gasification projects were under consideration. Many have since been discontinued because of the changing energy picture. R&D continues on a few processes, such as, ash agglomerating, fluidized-bed process, British Gas/Lurgi gasifiers, and the Rheinbraun direct fludizied-bed hydrogasification process.[36]

The Gas Research Institute (GRI) is finding R&D on the direct methanation process, which converts hydrogen and carbon monoxide to methane and carbon dioxide. The process can be used to treat raw

[36] Oak Ridge National Laboratory, op. cit., footnote 4, p. 23.

gas from a gasifier with little or no pretreatment. Direct methanation requires no steam. GRI hopes that direct methanation will improve the economics of converting coal to SNG.[37]

Also, advances in acid gas removal could improve the economics of SNG production from coal. One of the critical elements in producing SNG is the removal of unwanted gases, such as C02 and hydrogen sulfide, from the product stream. There are a number of commercial technologies that remove acid gases. However, only a limited R&D effort is directed at improving acid gas removal.[38]

Following the 1973-74 oil embargo, coal gasification became a valuable source of synthesis gas, which can be converted to chemicals and feedstocks. The $CO_2$ produced by the gasification process has a number of applications. For example, $CO_2$ is used in enhanced oil recovery operations, in the synthesis of urea (ammonia and fertilizers) and in the carbonation of beverages. Several plants use coal gasification to produce synthesis gas. A plant in Tennessee has been operating since 1983 and produces acetic anhydride, acetic acid, and methanol.[39]

### Liquefaction

Liquid fuels can also be synthesized by chemically combining coal with varying amounts of hydrogen and oxygen. Coal liquefaction processes are generally categorized according to whether liquids are produced from the products of coal gasification (indirect processes) or by reacting hydrogen with solid coal (direct processes).

The first step in the indirect liquefaction process is to produce a synthesis gas consisting of carbon monoxide and hydrogen and smaller quantities of various other compounds by reacting coal with oxygen and steam in a gasifier. The liquid fuels are produced by cleaning the gas, adjusting the ratio of carbon monoxide to hydrogen in the gas, and pressurizing it in the presence of a catalyst. Depending on the catalyst, the principal product can be methanol or gasoline.

A number of large-scale gasifiers required for the indirect liquefaction process have been commercially proven. These include the Lurgi, Westinghouse, Texaco, and Shell processes. For the liquefaction component of the indirect process, the Fischer-Tropsch process has proven effective. This process has been demonstrated and proven effective in South Africa for converting synthesis gas to a variety of products, including propanes and butanes, diesel, fuel oil, and methane.

The direct liquefaction process produces a liquid hydrocarbon by reacting hydrogen directly with coal, rather than from a coal-derived synthesis gas. A variety of direct liquefaction processes have been developed. These include pyrolysis, solvent extraction, and catalytic liquefaction. Much attention has been given to a process that dissolves and hydrogenates the coal at high temperatures (800 to 850 degrees Fahrenheit) and pressure (1,500 to 3,000 pounds per square inch (psi)), with or without catalysts.[40]

In the United States, direct liquefaction is the most advanced of all the potential processes for producing liquid fuels from coal. Between 1972 and 1982, four pilot plants demonstrated the feasibility of direct liquefaction. One of the plants, the Wilsonville, Alabama Advanced Coal Liquefaction Research and Development facility, is still operating. Since 1983, improvements have been made in the quantity and quality of the liquid fuels produced (distillate fuel oil, kerosene, and gasoline). The increases in quantity and quality have improved the economics of liquefaction. According to ORNL, the current liquefaction process would be cost-effective at a crude oil price of $35 per barrel.[41]

Further advances are possible. DOE efforts have focused on improving catalysts that will allow efficient liquefaction using lower pressure and temperatures.

## NON-FOSSIL FUEL ENERGY AND ADVANCED TECHNOLOGIES

Nuclear and renewable energy technologies provide less that 15 percent of our energy needs. However, many of the key decisions that will be

[37]Ibid.

[38]Ibid., p. 24.

[39]Ibid., pp. 24-25.

[40]Ibid., p. 33.

[41]Ibid., pp. 33-34. “

considered are related to these technologies. Furthermore, they can contribute significantly to energy security and environmental quality, especially reduced $CO_2$ emissions.

## *The Nuclear Power Option*

Nuclear power has come to an impasse for a variety of reasons. If there is to be a revival, many improvements are likely to be required to reactor technology and its management. In addition, progress on waste disposal must be sufficient to demonstrate convincingly that technology and sites for safe, permanent disposal will be available. Also, nuclear power is unlikely to be widely acceptable if it contributes, or has a significant potential to contribute, to the spread of nuclear weapons. Depending on how well these problems are met, nuclear power will either gradually wither away or resume its growth as a substantial contributor to our future energy needs.

Some observers doubt the viability of nuclear power. Construction costs are high, and overruns are common; catastrophic accidents are possible; and the problems and costs of waste disposal and plant decommissioning have not been resolved. In addition, foregoing nuclear power would enhance the moral leverage of nations seeking to stem the proliferation of nuclear weapons. The advantages to phasing out nuclear power, therefore, seem great.

Nevertheless, there are still strong national policy arguments for maintaining the option. An improved nuclear reactor may well be competitive with coal and much cheaper than oil or gas for electricity generation. Coal prices could also rise sharply with oil and gas if nuclear is not available as a competitor. Also, nuclear power is the only non-$CO_2$ option that can now be expanded rapidly.

The lack of nuclear plant orders since the mid-1970s raises questions of whether the industry will be able to respond adequately if new orders materialize. Specialized knowledge and facilities will be lost as the industry contracts. However, there is no "point of no return." Utilities are increasingly purchasing components for operating plants from foreign companies, and new orders could be supplied the same way, at least until the domestic industry rebuilds. Even entire reactors and major nuclear systems could be imported without great impact on the utility, its customers, or the national balance of payments. However, the situation is unlikely to get so extreme over the next few years. The major reactor vendors will probably be able to keep current, especially if it appears probable that a revival will occur, but many of the companies that produce minor but necessary components are dropping their certification. This suggests that the longer the hiatus before the next order, the slower the revival. Not only will design and manufacturing capabilities have to be rebuilt, but so will nuclear engineering departments at universities.

### Nuclear Powerplant Technology[42]

The technology has largely, though not completely, matured. If a utility were to order another nuclear plant now, it could start construction with an essentially complete design, and the final product should not differ markedly from this design. In addition, the advanced designs now being readied by several of the reactor manufacturers are incorporating safety and reliability features that should go a long way to solving many of the past problems.

However, reliability and safety concerns have been so pernicious that even the most experienced utilities would not consider nuclear to be a viable option at present. The hostility, negative expectations, and encumbrances that were created by all the problems have left a legacy that will not be dissipated simply by showing that most of the problems have been alleviated.

If it is deemed desirable to preserve the nuclear option, there are two basic approaches to overcoming the problems discussed above. The present light water reactor (LWR) technology can be improved sufficiently that utilities would feel secure ordering anew plant. Standardized designs would be licensed after exhaustive safety analysis. Each applicant would use a preapproved design not subject to generic safety issues, so utilities would not face continual changes during construction. Only site-specific features would require custom design and licensing. Issuance of the operating permit would depend only on showing that the construction met standards. These designs would improve on current designs by simplifying operations and increasing safety. The advanced LWRs are a major step in this

[42]This discussion is drawn from the OTA report, *Nuclear Power in an Age of Uncertainty*, OTE-E-216 (Washington, DC: U.S. Government fit@ Office, February 1984).

direction. This approach relies on the expertise that has been gained with several hundred LWRs in the world and the evolving maturity of a familiar technology.

Alternatively, an entirely different technology could be tried that should be so demonstrably safe that problems of changing regulation, public acceptance, and investor uncertainty should not be major factors. The high-temperature gas reactor (HTGR) and the liquid metal reactor (LMR) are alternative concepts that can incorporate passive safety features to the point where it is essentially impossible for an accident to occur that could result in off-site releases of radioactivity. However, both these concepts present uncertainties of operability and economics because of their unfamiliarity.

Both approaches (improved, familiar technology and radically different technology) have advantages and disadvantages. It should also be noted that it is entirely possible that neither will work, i.e., that the legacy of problems is so great that no reactor will prove acceptable.

No matter which approach is tried, standardization will be important. No nuclear plant will be cheap, and no utility is going to start construction without assurances that the plant will be both licensable and well designed to be operable and efficient. No reactor vendor or architect/engineer is likely to go to the trouble and expense of designing a plant and licensing the design unless it can apportion these costs among many sales. Standardization is the only way to meet these constraints. Customized plants can be just as safe and, under some conditions, just as economic, but for the next round of orders, standardization offers practical assurances of licensing and construction that are probably essential.

It is also noteworthy that any new plants in the United States are likely to be smaller than those from the early days of nuclear power. Due to uncertainties of future load growth and rate regulatory treatment, utilities are avoiding large plants of any type. All parties will want to limit their financial risk, and small plants cost much less though somewhat more per kilowatt of capacity. It should be much easier to demonstrate compliance with regulations and cost projections of a small plant since it would be more practical to build a full-scale demonstration model.

The ideal may well be modular units that can be largely factory manufactured and delivered rapidly as needed. Reactors are unlikely ever to be as simple to install as combustion turbines, but recent experience suggests (not unambiguously) that large plants are more subject to delays and cost escalation than small plants. Manufacturers are likely to find innovative ways to package small reactors that further reduce costs. Thus the economies of scale of large plants are probably not as great as has been thought in the industry and may be outweighed by other advantages of small units. Small, modular reactors are particularly appropriate for standardization as they will be assembled from components that can be serially manufactured. As the number of reactors ordered increases, costs should drop.

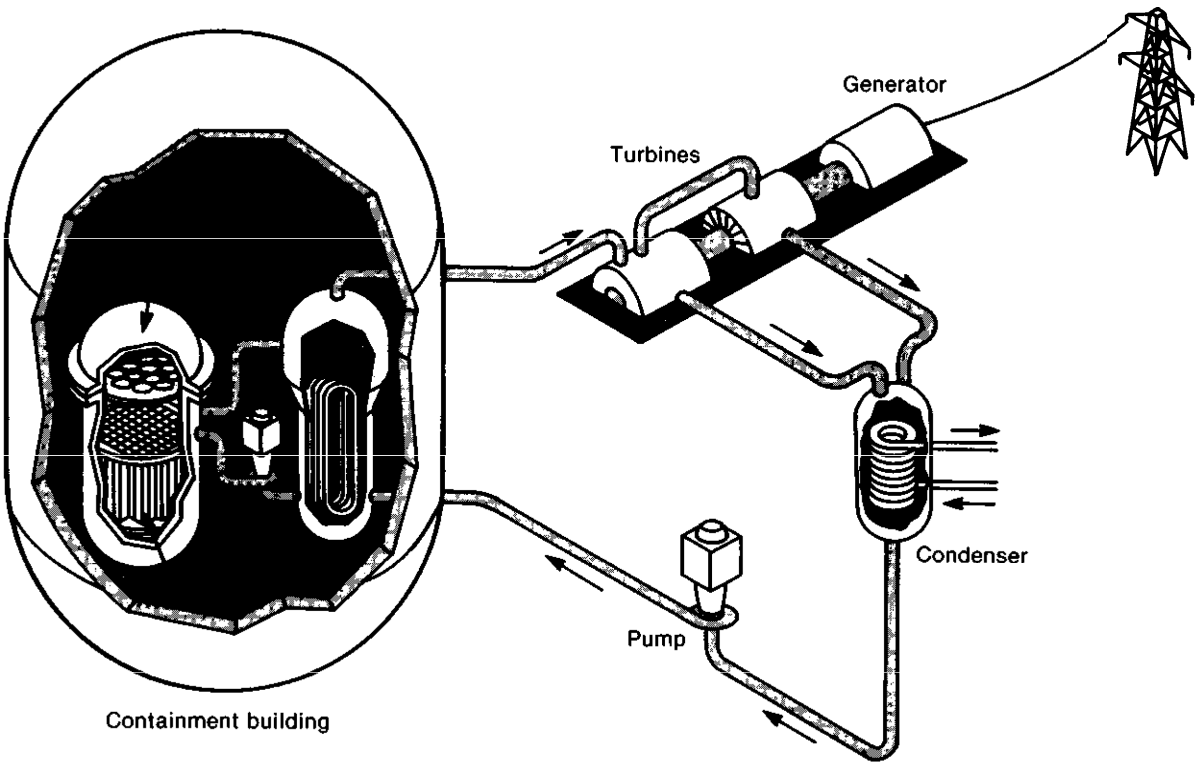
*Advanced Light Water Reactor*—Two different reactor designs have been developed for the LWR: *the pressurized water reactor (PWR)* and the *boiling water reactor* (BWR) (see figures 3-3 and 3-4). The PWR maintains its primary coolant under pressure so that it will not boil. The heat from the primary system is transferred to a secondary circuit through a steam generator, and the steam produced there is used to drive a turbine. In the United States, about two-thirds of the nuclear reactors are pressurized water reactors.

The BWR eliminates the secondary coolant circuit found in a PWR. In the BWR, the heat in the core boils the coolant directly, and the steam produced in the core drives the turbine. There is no need for a heat exchanger, such as a steam generator, or for two coolant loops. In addition, since more energy is carried in steam than in water, the BWR requires less circulation than the PWR.

LWRs have been operating in the United States for more than 25 years. They have had good safety records. There has never been an accident involving a major release of radioactivity to the environment. Their operating performance, while not as good as expected initially, has been comparable to that of coal-fired powerplants.

Improvements could be made to LWRs by redesigning the plants to address safety and operability concerns. Advanced LWR designs have been developed by Westinghouse Electric Corp. and General Electric Co. Efforts have been directed at reducing risks and improving reliability. For example, the new BWR design enhances natural circulation of the primary coolant, which increases the ability of the

**Figure 3-3-Pressurized Water Reactor**




SOURCE: U.S. Congress, Office of Technology Assessment, *NuclearPowerinan Age* of Uncertaintv. OTA-E-216 (Washington. DC: U.S. Government Printing Office, February 1964), figure 20.

coolant to remove decay heat in the event the main circulation system fails. In the new PWR design, coolant piping has been reconfigured and the amount of water in the core has been increased to reduce the possibility that a pipe break could drain the primary coolant enough to uncover the core.

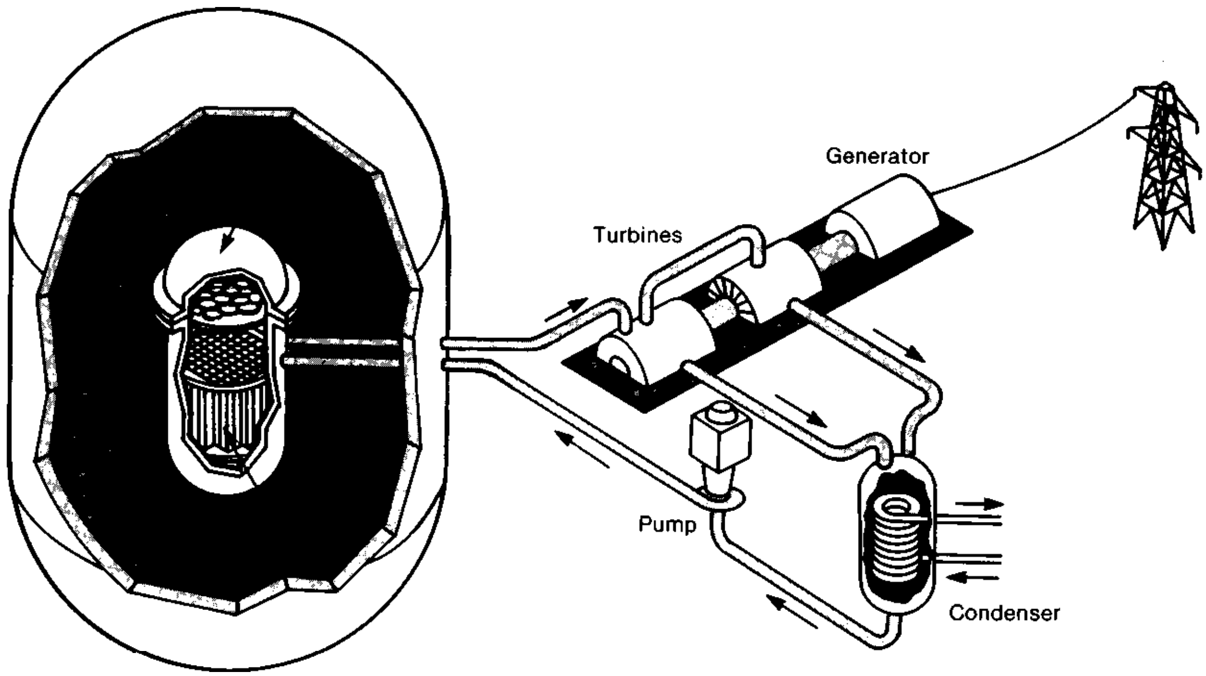
*Inherently Safe Advanced Reactor Concepts*— Incentives for developing a more forgiving reactor arise from several sources. LWR designs have evolved in a patchwork fashion, and there are still a number of unresolved safety and reliability issues. Also, the Three Mile Island accident heightened concerns about the susceptibility of LWRs to serious mishaps arising from human error. A more forgiving reactor design became desirable in terms of investment protection as well as public health and safety.

The *modular high-temperature gas-cooled reactor* (MHTGR) is an example of an effort to develop an inherently safe reactor. The MHTGR is cooled by helium and moderated by graphite, and the entire core is housed in a prestressed concrete reactor vessel. The reactor uses enriched uranium along with thorium, which is similar to nonfissionable uranium in that it can be transformed into useful fuel when it is irradiated. The fuel particles are coated with multiple layers of ceramic material and carbon. The ceramic coating can withstand extremely high temperatures (up to 1,600 degrees Celsius) without damage.

Because helium is used instead of water as a coolant, the MHTGR can operate at a higher temperature and a lower pressure than an LWR. This results in a higher thermal efficiency for electricity generation than can be achieved with other reactor designs. It also makes the MHTGR particularly suited for the cogeneration of electricity and process heat.

The gas-cooled reactor has several inherent safety characteristics that reduce its reliance on engineered devices for safe reactor operation. First the use of helium as a primary coolant offers some advantages. Because helium is noncorrosive in the operating

**Figure 3-4-Boiling Water Reactor**




SOURCE: U.S. Congress, Office of Technology Assessment, *Nuclear Power inan Age of Uncertainty* OTA-E-216 (Washington, DC: U.S. Government Printing Office, February 1984), figure 20.

temperature range of the reactor, it causes little damage to components. Furthermore, it is transparent to neutrons and remains nonradioactive as it carries heat from the core. Also, the design of the fuel and core structure for the gas-cooled reactor has inherent safety features. The fuel can withstand very high temperatures, and the large thermal capacitance of the graphite in the core and support structures would slow the temperature rise even if the flow of coolant was interrupted. Operators would have a great deal of time to diagnose and correct a situation before the core is damaged. Even if all measures fail, heat transfer out of the core should always be high enough to prevent damage to the fuel pellets and resultant catastrophic release of radioactivity.

The high-temperature gas-cooled reactor was successfully demonstrated in 1967. The plant, Peach Bottom 1, operated at an average availability of 88 percent. A much larger plant that was to have been the prototype for commercial plants was built at Fort St. Vrain, Colorado. This reactor, now closed, suffered from many problems though the nuclear part worked well. These problems are partly responsible for a change in direction to smaller, modular gas reactors.

Preliminary conceptual design of a modular reactor has been completed. The simplification of plant design using passive features and factory fabrication should overcome the economic disadvantages of smaller size. Because of its modest size and passive safety features, the MHTGR technology is well suited to export markets. A number of countries have expressed interest in the MHTGR. They include the U. S.S.R., Italy, Israel, and China.

In addition to the MHTGR reactor, a small, passively safe liquid metal reactor (LMR) is being developed-the *power reactor inherently safe module* (PRISM). The PRISM technology uses liquid sodium to cool the reactor core. The reactor vessel is housed in an outer "guard" vessel. The purpose of the outer vessel is to catch any leaking sodium. There is a 5-inch gap between the two vessels, which is filled with argon to prevent the reaction of sodium with air. Both vessels are placed in an underground concrete silo. Air is allowed to circulate freely between the silo wall and the "guard" vessel to

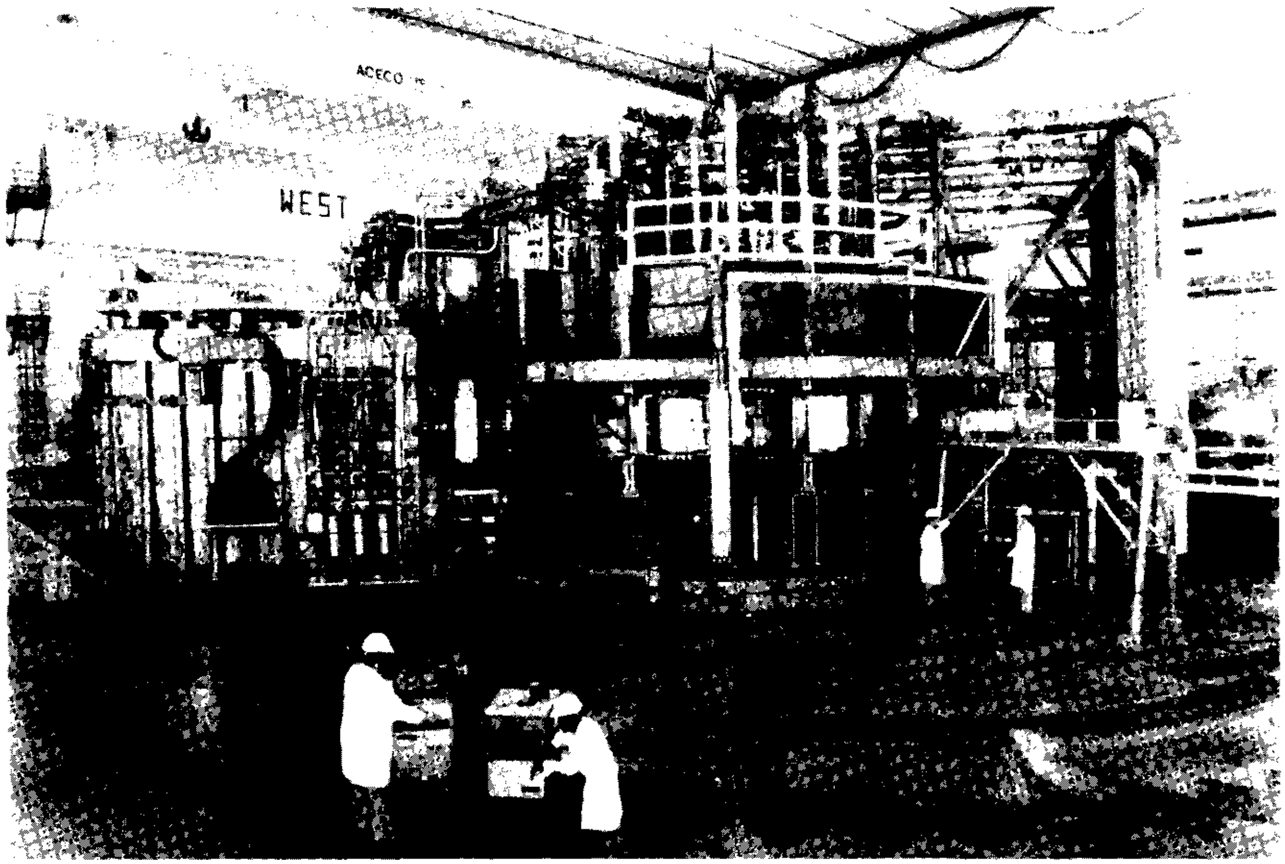



*Photo credit: Princeton Plasma Physics Laboratory*

**The Tokamak Fusion Test Reactor at Princeton Plasma Physics Laboratory, where the first ever experiments on deuterium-tritium plasmas are scheduled to occur in 1993.**

remove residual heat passively to the outside. DOE is funding PRISM research, and conceptual designs are expected to be completed in 1991.[43]

### Resource Extension

The technologies for fuel reprocessing and breeding are well developed. Over the last three decades the United States has spent about $16 billion on breeder reactor technology. The liquid metal sodium-cooled fast breeder reactor (LMFBR) is the system of choice for breeding.[44]

The LMFBR is conceptually similar to the LMR. However, the LMFBR has a higher breeding ratio. The LMFBR can convert uranium-238 into fissile plutonium at a rate faster than its consumption of fissile fuel.

The reactor fuel rods contain a mixture of plutonium dioxide and depleted uranium dioxide. A blanket of rod containing depleted uranium dioxide surrounds the core. The initial loading could use either plutonium recovered from spent light water reactor fuel or enriched uranium. Subsequent loadings would use plutonium bred in the LMFBR.

The most serious risks from reprocessing are increased opportunities for the proliferation of weapons and the possibility of nuclear terrorism. Little economic justification exists now for reprocessing but, as the number of reactors grows, uranium prices will eventually rise. So will the value of the plutonium, leading to economic incentive to recover and recycle.

[43]"New Interest in Passive Reactor Designs," *EPRI Journal*, vol. 14, No. 3, April/May 1989, pp. 10-12.
[44]Oak Ridge National Laboratory, op. cit., footnote 4, p. 58.

### *Fusion*

Over the past *35 years,* there has been great progress in nuclear fusion research, but there remain many scientific and technological issues that need resolution before fusion reactors can be designed and built. According to OTA, 30 years of additional R&D are required before a prototype commercial fusion reactor can be demonstrated. If successfully developed, fusion has the potential to provide society with an essentially unlimited source of electricity. It may also offer significant environmental and safety advantages over other energy technologies. Fusion technology is beyond the timeframe of this report, but it is one of only three long-term options. R&D must continue on fusion if the United States is to have the technology by the mid-21st century.

Nuclear fusion is the process by which the nuclei of two light atoms combine or fuse together. The total mass of the final products is slightly less than the total mass of the original nuclei, and the difference-less than 1 percent of the original mass-is released as energy.

Hydrogen, which is the lightest atom, is the easiest to use for fusion. Two of its three isotopes, deuterium and tritium, in combination work best in fusion reactions. When deuterium and tritium react, kinetic energy is released. This energy is converted to heat, which then can be used to make steam to drive turbines.

However, certain conditions must be met before hydrogen nuclei fuse together. The nuclei must be heated to about 100 million degrees Celsius. At these temperatures, matter exists as plasma, a state in which atoms are broken down into electrons and nuclei. Keeping a plasma hot enough for a long enough period of time, and effectively confining it are crucial for generating fusion power.

The behavior of plasmas, and the characteristics, advantages, and disadvantages of various confinement concepts need further study. At this stage, it is not known which confinement concept can form the basis of an attractive fusion reactor. The tokamak, which is a magnetic confinement concept, is the most developed, attaining plasma conditions closest to those required in a fusion reactor. Its principal confining magnetic field is generated by external magnets that run in toroidal direction. The tokamak also contains a poloidal magnetic field that is generated by electric currents running within the plasma.

Research on alternatives to the tokamak continues because it is not clear that the tokamak will result in the most attractive or acceptable fusion reactor. For an indepth discussion of fusion R&D, the reader is referred to the OTA report *Star Power: The U.S. and the International Quest for Fusion Energy.*

### *Future Electricity Supply Options*

*The* U.S. electric power industry experienced tremendous change during the 1970s and 1980s, leading to considerable uncertainty. Because of this uncertainty, utilities now consider a broader range of options to accommodate future demand. In addition to its reliance on conventional technologies, utilities employ less capital-intensive and nontraditional options to ensure supply adequacy. These include load management and conservation programs, life extension of existing facilities, smaller-scale power production, and increased purchases from other utilities and nonutility generators. These options offer utilities more flexibility in responding to demand fluctuations.

Utilities are using demand management programs to reduce system peak demand and to defer the need for future generating capacity additions. Demand management programs include activities undertaken by a utility or customer to influence electricity use. Some utilities are just initiating demand management programs while others have been heavily involved for years and very dependent on these programs to meet system electricity needs. Demand management programs are discussed in chapter 2.

Life extension or plant improvement options are receiving more attention as a way of deferring the need for new capacity. Many of the older (30 or more years) plants have attractive unit sizes (100 MW or larger) and performance characteristics (heat rates close to 10,000 British thermal unit/kilowatt hour (Btu/kWh)). And, in many cases, plant improvement can also increase efficiency up to 5 to 10 percent and/or upgrade capacity. Refurbishments are underway at a number of utilities. For more detailed information about plant improvement opportunities, see OTA's assessment New *Electric Power Technologies: Problems and Prospects for the 1990s.*

Purchasing power from other utilities and nonutility generators is yet another option to ensure supply adequacy. The development of sophisticated communications equipment and control technologies and cost differentials have fostered an increasingly active market in bulk power transactions among utilities. Bulk power transfers constitute a significant share of total U.S. electricity sales. Canadian power imports are also increasing.

This section focuses on a number of new promising technologies for electric power generation. These include the intercooled steam injected gas turbines, combined cycle conversion, and fuel cells.

### Advanced Turbines

Turbines fueled by oil or gas have provided electric power for five decades. They were used primarily to meet peak loads because of their relatively low efficiency. Recently, they have attracted renewed attention because of their low capital cost and improved fuel efficiency. New turbine technologies and advanced materials have allowed for hotter combustion temperatures. Many of the advances in design and high-temperature materials for turbines result from military R&D for improved jet engines.

The steam injected gas turbine (STIG) has far greater power and electrical efficiency than older designs, as discussed in the cogeneration section of chapter 2. The addition of intercooling to the STIG (ISTIG) should further increase power and efficiency improving their value for central power station applications. Part of the incoming compressed air used for combustion is passed through the turbine blades for cooling. This permits higher combustion temperatures. General Electric is conducting design work and indicates that this technology will be able to reach an average efficiency of 48.3 percent at an installed capital cost of $400/kW.[45]

Adding a steam turbine to a combustion turbine is another relatively new approach, called the combined cycle. A combined cycle powerplant is highly fuel efficient (up to 47 percent).[46] The steam turbine portion of a combined cycle plant can be added long after the combustion turbine has been in service, allowing greater planning flexibility. A key technological development allowing for widespread acceptance of combined cycle plants has been improving the reliability of the combustion turbines.

It may also be economically feasible to convert a combined cycle plant to run on gas derived from coal, as in an IGCC system. The turbine initially can be freed by natural gas, delaying construction of the coal gasifier until fuel prices and other economic conditions warrant. The IGCC is discussed in the coal section of this chapter.

### Fuel Cells

Fuel cells produce electricity by an electrochemical reaction between hydrogen and oxygen, which, at least in theory, can produce electricity much more efficiently than current technology for burning fuel. The hydrogen can be supplied by a hydrocarbon fuel. A typical fuel-cell powerplant consists of three major components: fuel processor, fuel-cell power section, and power conditioner. The fuel processor extracts hydrogen from the fuel. The hydrogen is then fed into the fuel-cell power section. The fuel cells are joined in a series of stacks which form the powerplant. The electrical power that flows from the stacks is direct current (DC). With some voltage regulation, the DC power can be used if the load is capable of operating with DC. Otherwise a power conditioner is required to transform the DC into alternating current (AC). Neither combustion nor moving parts is required in the production of power. A single fuel cell produces about 1 volt.

There are several types of fuel cells being developed. They are categorized according to the type of electrolyte used in the conversion process. Fuel cells that use phosphoric-acid as the electrolyte are the most developed, but concerns about performance and costs persist. The phosphoric-acid fuel cell is likely to account for most of the fuel cells deployed in the 1990s. Other fuel cells employ alternative electrolytes such as molten carbonate and solid oxide. Molten carbonate and solid oxide fuel cells reform hydrocarbon fuels directly in the cell. These fuels cells, which operate at high temperatures, produce waste heat that can be used for cogeneration applications. The molten carbonate and solid oxide fuel cells are not expected to be deployed until the late 1990s at the earliest.

[45] Robert H. Williams and Eric D. Larson, "Expanding Roles for Gas Turbines in power Generation," reprinted *from Electricity—Efficient End- Use and New Generation Technologies,* and *Their Planning Implication* (no date), p. 531.

[46] "Utility Turbopower for the 1990s," *EPRI Journal,* April/May 1988, pp. 5-13.

Fuel cells are expected to produce electricity with modest environmental impacts relative to those of combustion technologies. Efficiency is estimated to be between 36 to 40 percent for smaller units and 40 to 44 percent for larger ones, and future technology may realize efficiency rates well over 50 percent. Another advantage is the short leadtime (2 to 5 years) required to build a fuel-cell powerplant. Because fuel cell systems are modular, they can be built at a factory and assembled at the site. Installation can be accomplished in many locations, including areas where both available space and water are limited. Other advantages include fuel flexibility and responsiveness to changes in demand.[47]

The installed capital costs of prototype fuel-cell powerplants are about $3,000/kWe. The fuel cell power section will account for about 40 percent of the costs. Operating and maintenance costs are estimated to range from 4.3 to 13.9 mills/kWh. Replacing cell stacks will account for the largest share of operation and maintenance costs. Fuel costs are expected to be about 27 to 33 mills/kWh.[48]

### Magnetohydrodynamics

In magnetohydrodynamic (MHD) generators, a stream of very hot gas from a furnace (about 5,000 degrees Fahrenheit) flows through a magnetic field at high velocity. Because the gas is an electrical conductor, current is produced through electrodes mounted on the sides of the gas duct. Used in conjunction with conventional power technology, MHD might raise plant efficiency by 10 percent. However, many difficult technical problems remain unsolved, especially for coal-freed MHD systems. Perhaps the strongest argument for continuing a high level of R&D activity is the promise of being able to extract more useful energy from coal if concerns over $CO_2$ emissions prove accurate.

### Storage[49]

Electricity storage is of enormous benefit to utilities. Storage reduces the amount of generating capacity that is required to meet peak loads and spinning and transmission reserves. Utility customers also can use storage devices to avoid the high price of electricity during peak periods.

Advanced batteries, compressed air energy storage (CAES), and pumped hydro are storage technologies that are well developed and could, under certain circumstances, be used in the 1990s.

*Advanced* Batteries-Batteries are more efficient and flexible than mechanical energy storage systems. In addition, they are modular and thus require short leadtimes to construct. Capacity can be added as needed and sited near the intended load. A battery's ability to react in a matter of seconds makes it valuable for optimizing a utility's operations.

Three types of utility-scale batteries are promising: advanced lead, zinc-chloride, and sodium sulfide (NaS) batteries. Lead batteries are widely used today, mostly in cars.

Lead-acid batteries consist of a negative lead electrode and a positive lead dioxide electrode immersed in an electrolyte of sulfuric acid. As the battery discharges, the electrodes are dissolved by the acid and replaced by lead sulfate, while the electrolyte becomes water. When the battery is recharged, lead is deposited back on the negative electrode, lead peroxide is deposited back on the positive electrode, and the concentration of acid in the electrolyte increases.

Over the years, research has continually improved lifetime cycles of the lead-acid battery. It is possible to buy a load-leveling lead-acid battery with a guaranteed lifetime of 1,500 cycles (about 6 years). Refinements could further improve the lifetime up to 3,000 to 4,000 cycles.

One of the disadvantages of lead-acid batteries is capital cost. Operation and maintenance costs are dependent on the durability of various battery components in a corrosive environment and how the battery is used. According to OTA, the largest component of operation and maintenance costs will most likely stem from the periodic replacement of battery stacks.

Zinc-chloride batteries have been under development since the early 1970s. During charging, zinc is removed from the zinc-chloride electrolyte and deposited onto the negative graphite electrode in the

[47]Oak Ridge National Laboratory, *Energy Technology R&D: What Could Make a Difference?* vol. 2, Part 1, "End-Use Technology," ORNL-65441/V2/P1, December 1989, p. 138.

[48]U.S. Congress, Office of Technology Assessment, op. cit., footnote 27.

[49]Unless otherwise noted, most of this section is based on the OTA report *New Electric Power Technologies: Problems and Prospects for the 1990s*, op. cit., footnote 27. For more information on this topic the reader is referred to this report.

battery stack. Chlorine gas is formed at the positive electrode. The gas is pumped into the battery pump, where it reacts with water at 10 degrees Celsius to form chlorine hydrate, an easily manageable slush. During discharge, the chlorine hydrate is heated to extract the chlorine gas, which is pumped back into the stack, where it absorbs the zinc and releases the stored electrical energy. The zinc-chloride technology is complex and is sometimes described as being more like a chemical plant than a battery.

Cost estimates for the zinc-chloride battery are about $500/kWe, less expensive than the lead-acid type because of the inexpensive materials that go into its manufacture. The operation and maintenance costs are uncertain. However, the expected longer lifetimes and less expensive replacement costs for the stacks and sumps could levelize replacement operation and maintenance costs in the 3- to 9-mills/kWh range.

A major safety concern is associated with the accidental release of chlorine. Because chlorine is stored in a solid form, sumps must be sufficiently insulated so that in the event of a refrigeration system malfunction the chlorine will stay frozen.

Interest in commercializing the NaS battery is strong, and funding has reached about $140 million annually.[50] The NaS battery system requires an operating temperature of 350 degrees Celsius. At this temperature, both the sodium and sulfur are liquid. During discharge, sodium is oxidized at one electrode and travels through the electrolyte where it is reduced at the second electrode to form sodium polysulfide. The major advantages of the NaS battery are its high overall efficiency (88 percent) and its high energy density compared with that for the lead-acid battery. One of the primary concerns over this technology is maintainingg the high operating temperature during both charging and discharging. Fluctuations in temperature will result in electrolyte cracking.[51]

*Compressed Air Energy Storage—A* CAES plant is a central storage station where off-peak power is used to pressurize an underground storage cavern with air. The compressed air is later released to drive a gas turbine. The frost U.S. CAES project was scheduled to begin commercial operation in March 1991. Alabama Electric Cooperative, Inc. owns the 11O-MW plant.[52]

In a conventional plant, the turbine must power its own compressor, which leaves only about one-third of the turbine's power available to produce electricity. The compressed air from a CAES is used in a turbine which, freed from its compressor, can drive an electric generator up to three times as large. The gases discharged from the turbine pass through a "recuperator,' where they discharge some of their heat to the incoming air from the cavern, increasing the overall efficiency of the plant. (See figure 3-5.)

Three types of caverns may be used to store air: salt reservoirs, hard rock reservoirs, or aquifers. The salt reservoirs are found in Louisiana and eastern Texas. Salt caverns are mined by pumping a water-based solution into the deposit and having it dissolve a cavern. Salt caverns are air tight.

Rock caverns are located throughout the United States. They are excavated with underground mining equipment. A compensation reservoir on the surface maintains a constant pressure in the cavern as the compressed air is injected and withdrawn. Aquifer reservoirs are naturally occurring geological formations, occurring in much of the Midwest, the Four-Corners region, eastern Pennsylvania, and New York. They consist of porous, permeable rock with dome-shaped, nonporous, impermeable cap rock overlying them. The force of the surrounding water confines the compressed air and maintains it at a constant pressure as it is injected and withdrawn from the rock.

Compared to batteries, CAES plants are in a more advanced stage of development and are likely to be less expensive than batteries on a dollar per kilowatt-hour basis. However, CAES plants require longer leadtimes to construct, probably from 4 to 8 years, depending on size.

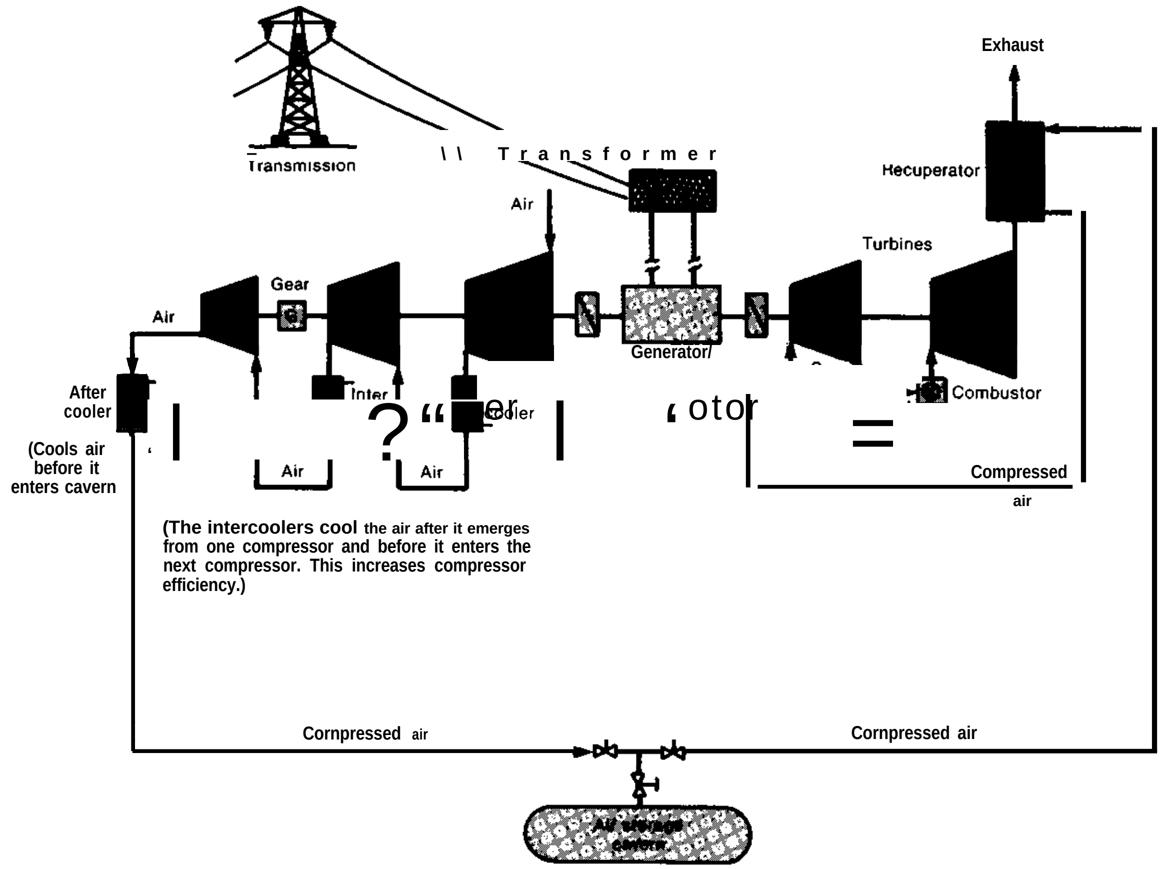
*Pumped Hydro--There are* numerous pumped hydro plants in the United States. Some plants require a large, above-ground reservoir while others store water underground. Above-ground reservoirs have become difficult to site, and underground storage is only economical in very large units.

m@& Ridge National Laboratory, "End-Use Technology, " Op. Cit., footnote 47, p.163.

'lIbid.

52" Compressed Air Used To Produce Economical Peak power, " *Power, vol.* 134, No. 6, June 1990, p. 77.

**Figure 3-5-First Generation CAES Plant**




A Compressed Air Energy Storage (CAES) plant is a modification of a conventional gas turbine cycle. Its principal components are combustion turbines, compressors, a generator/motor, and an underground storage cavern. The system stores energy by using electricity from the grid to run the compressor and charge the cavern with compressed air. This energy is discharged by releasing the compressed air to the combustion turbine where it is mixed with natural gas or oil and burned to produce the power which drives the generator. In a conventional gas turbine plant the turbine drives its own compressor simultaneously with the generator so that only a third of the turbine's total power is available to produce electricity. Thus, a CAES plant stores the energy in off-peak electricity to make a gas turbine three times as fuel efficient.

A Compressed Air Energy Storage (CAES) plant is a modification of a conventional gas turbine cycle. Its principal components are combustion turbines, compressors, a generator/motor, and an underground storage cavern. The system stores energy by using electricity from the grid to run the compressor and charge the cavern with compressed air. This energy is discharged by releasing the compressed air to the combustion turbine where it is mixed with natural gas or oil and burned to produce the power which drives the generator. In a conventional gas turbine plant, the turbine drives its own compressor simultaneously with the generator so that only a third of the turbine's total power is available to produce electricity. Thus, a CAES plant stores the energy in off-peak electricity to make a gas turbine three times as fuel efficient.

SOURCE: U.S. Congress, Office of Technology Assessment, New Electric *Power Technologies: Problerns and Pmspecfe for the 19Ws,* OTA-E-2~ (Washington, DC: U.S. Government Printing Office, July 19S5), figure 4-27.

A pumped storage plant recycles the water that flows through its turbine, sending it through a reversible turbine from a lower to an upper reservoir for reuse. Although pumped storage facilities use more energy for pumping than they generate for power, they assist in peak power production, when electricity is most costly to produce. Replenishing the upper reservoir occurs during off-peak hours using the utility's least costly resources.

Expanded use of pumped storage facilities could improve overall efficiency. Currently, U.S. pumped storage capacity is only 3 percent of the country's total capacity. Foreign studies suggest that increas-

[53] Solar Energy Research Institute et al., *The Potential of Renewable Energy, an Interlaboratory White Paper,* prepared for the U.S. Department of Energy (Golden, CO: Solar Energy Research Institute, March 1990), p. A-3.

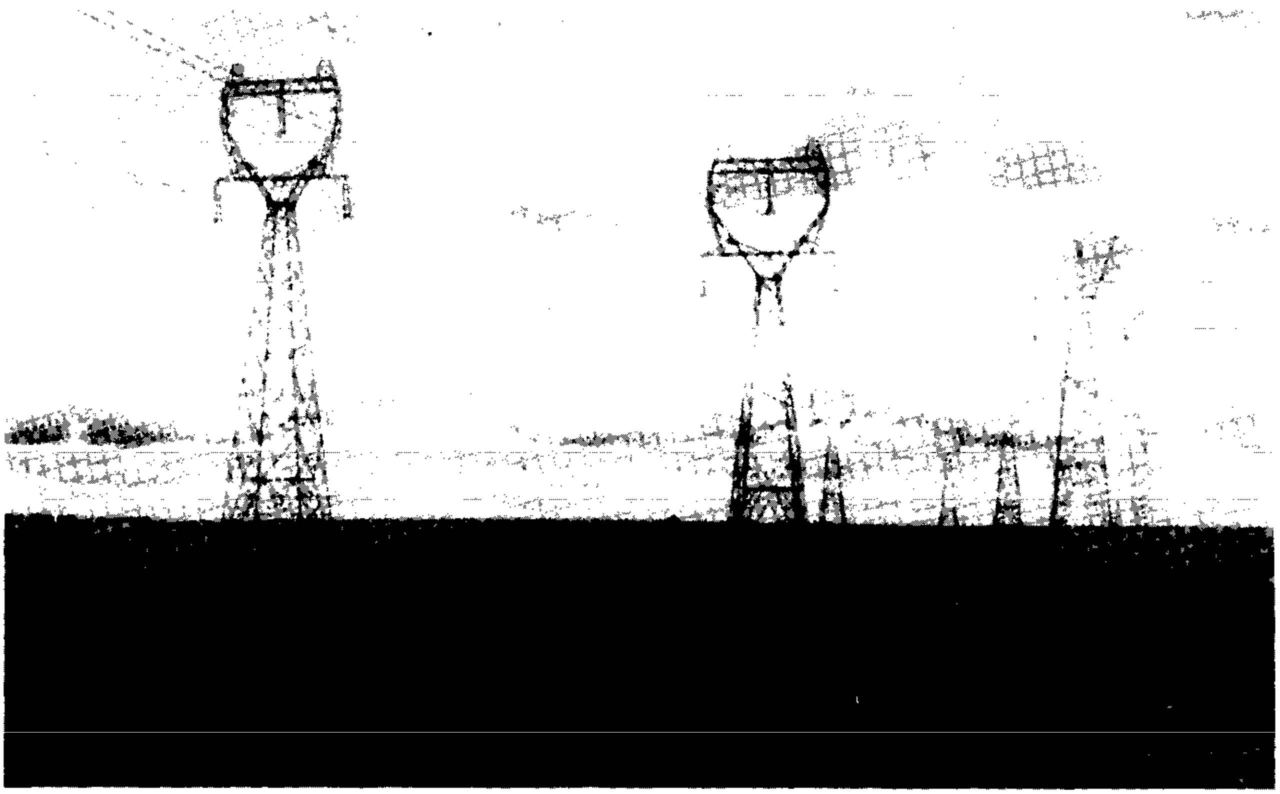


Photo credit: Casazza, Schultz & Associates, Inc.

A high-voltage transmission corridor.

*ing the* share to *20* percent might benefit the U.S. power grid.[53]

Other storage technologies are flywheels, and superconducting magnet energy storage. These technologies are not likely to be commercial before the year 2000.

## Transmission and Distribution

Transmission and distribution lines carry electric energy from the powerplant to the user. Most transmission in the United States consists of overhead AC lines operated at 69 kilovolt (kV) or above. Distribution systems operate at lower voltages, typically under 35 kV, to transport smaller amounts of electricity relatively short distances.

Transmission systems are extraordinarily complex. They must be developed in concert with generating plants, but utilities are experiencing increasing difficulty in siting lines. Few important lines have been stopped, but that may not be true in the future. One of the major issues is the health effects of electric and magnetic fields, discussed later in this chapter. The technical options discussed here may help alleviate some of the concerns.

In recent years, long-distance transmission has increased significantly. Transmission capacity in some regions is already strained by the high usage. Improvements in transmission and distribution technologies can improve performance and reliability. Options for increasing transmission capability include improving control of reactive power and voltages on a network and increasing the thermal or voltage capacity of an individual existing line, improving control of power flows on a network, decreasing the response time of generators and transmission line switching, and adding new lines.

Developments that may have significant long-term effects on transfer capability are high-power semiconductors, advances in computer and data processing, and in the very long term, possibly even superconductivity. High-power semiconductors are now being used on high voltage direct current (HVDC) powerlines to convert AC power to HVDC and back again. The high-power semiconductors (thyristors) used in this application are expensive enough that HVDC powerlines are only practical in long lines or as interconnections between asynchronous systems. Lower cost and high-capacity semiconductors will make shorter DC lines economically practicable and allow multiterminal HVDC lines, instead of the two terminals now used. Because the conversion voltages at both ends of the line can be controlled, HVDC transmission allows complete control of network flow.

Advances in communication and data processing should improve reliability and economy. The current transmission and distribution system is largely mechanically controlled. The development of more flexible transmission controls and distribution automation will allow more efficient operation, but at the price of complexity.

Superconductors will have a number of possible applications in the utility industry. These include: 1) magnetic energy storage, 2) superconducting generators, and 3) transmission lines.

Electricity storage may be the most likely early use of superconductors. The concept is less developed than the storage technologies discussed earlier, but superconducting magnets could be more economical and easily sited. The difficulties of this application include cost, refrigeration, and the enormous magnetic stress on brittle ceramic superconductors.

Another possible application is superconducting generators. preliminary designs and testing have been done using lower temperature metal superconductors. Even small reductions of losses can be important because of the high-power flow involved.

Superconducting transmission lines are another possible application, but not as attractive as they might first appear. Although superconducting cables would have no resistance, this would have to be balanced against cooling losses and the cost of the cable and burial. HVDC circuits would benefit much more from superconducting lines. The cost of AC/DC conversion equipment will limit the use of superconducting lines until the price of high-power semiconductors declines. For more information about superconductivity, please see the OTA report *High-Temperature Superconductivity in Perspective.*

### Hydrogen

Many technologies such as nuclear power and emerging options such as photovoltaics and wind are most suitable for the production of electricity. Insofar as the electricity can be loaded onto the power network and delivered to customers, that is the most efficient method. However, electricity has some significant disadvantages as an energy carrier. At present it cannot be stored economically, and it is expensive to transport long distances although, as discussed above, new technologies may change these conclusions.

A potential alternative is to produce hydrogen, most probably by electrolyzing water, and delivering it via pipelines, much like natural gas. Hydrogen provides inherent storage, as does natural gas; it is less expensive to ship long distances than electricity; and it can be consumed almost as cleanly—the combustion product being water vapor (a small amount of $NO_x$ may also result).

However, hydrogen also involves several disadvantages. Costs would be high unless the electricity is extremely inexpensive (in which case the losses of long-distance transmission and storage of electricity would not be very important). Losses in the electrolysis process and in compressing and delivering the hydrogen would be substantial. Pipelines built for natural gas could be unsuitable because hydrogen can embrittle steel pipes, shortening their lifetimes, and because the energy density is lower than natural gas, limiting the amount that can be delivered. Thus new and expensive pipelines could be required.

The easiest displacement would be of natural gas, but demand for gas is greatest for heating in the winter, when most renewable energy technologies have relatively low output. Thus, annual storage would be required if hydrogen were to become a significant part of the energy system. Hydrogen would be more valuable as a replacement for gasoline, but storage in small quantities in automobiles would be almost as difficult as storing electricity in batteries.

Hydrogen may play an important role eventually because of its natural partnership with intermittent solar technologies, but first the cost of those technologies must drop to very competitive levels. Lowering the costs of producing and storing hydrogen is the focus of DOE R&D efforts. Much R&D

effort is still needed to bring hydrogen concepts to the demonstration stage.

### *Renewable Energy Technologies*

Renewable energy sources can supply space and process heat as well as electrical power. Some sources can be converted to feedstocks, for producing chemicals, or to fuel, for transportation. In general, the resource bases are inexhaustible and widely but irregularly distributed in both space and time, making storage very important. And, although the potential of each resource seems enormous, only a small amount of the resource is economically recoverable at present. As a group, renewable energy technologies are relatively clean and provide needed protection against a disruption in oil supplies. New energy technologies will enhance U.S. competitiveness and help reduce the trade deficit.

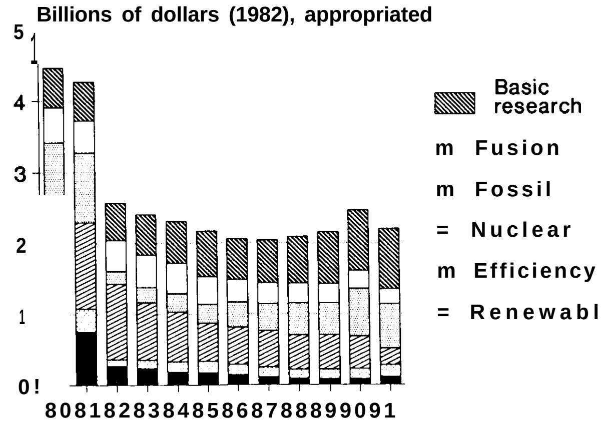
Continued R&D are needed to improve the efficiencies of promising renewable technologies, to reduce the risk of new technologies, and to help integrate renewable into existing energy systems. Yet, Federal funding for renewable R&D has declined over the last decade (see figure 3-6). Several recent studies have suggested that for a comparatively small increase in investment, the Federal Government could significantly hasten the development and deployment of renewable technologies. The Solar Energy Research Institute (SERI) and ORNL have concluded that the Federal budget for renewable R&D was only about half of what could be technologically justified.[54]

#### Hydroelectricity

Hydroelectric facilities use the kinetic energy in flowing water to generate electricity. Most hydropower facilities capture and store water via dams and reservoirs. Others operate in a run-of-river mode whereby water flow is not altered. Hydropower-generating capacity is affected by the volume flow of water and the difference in elevation of the water as it passes through the plant.

In 1989, hydroelectric power contributed about 2.7 quads to total U.S. energy supplies.[55] Hydro-

**Figure 3-6-DOE Energy R&D Budget: 1980-1991 Selected Budget Lines**




SOURCE: Congressional Research Serviee, Energy *Conservation: T~-dca/Etiiu"encyan dProgram Effectiveness, 1885130,* Updated Apr. 2,1991, table 2.

power represents about 12 percent of installed electric generating capacity. Although the overall capacity of hydropower has doubled since 1960, the growth rate has slowed. The 88 gigawatts (GW) of present capacity include 64 GW of conventional hydro, 17 GW of pumped hydro, and 7 GW of small-scale (30 MW or less) hydro.[56]

According to SERI, only about half of the Nation's hydropower capability has been developed.[57] As of January 1, 1988, the United States has 76.1 GW of conventional hydropower and 19.1 GW of pumped storage capability still untapped. Of this amount, DOE estimates that for conventional hydropower it is economical to develop only 30 percent, or 22 GW, given current economic and regulatory constraints. By the year 2030, a net increase of 8-GW conventional and 5-GW pumped storage is projected, a growth of less than 0.5 percent per year.[58]

Hydropower is an attractive energy source because it is clean, it takes advantage of a large domestic resource base, and it responds quickly to utility load swings. Its availability (95 percent on average) is greater than that of thermal generating

[54] U.S. Congress, Office of Technology Assessment, *Changing By Degrees: Steps To Reduce Greenhouse Gases,* OTA-O-482 (Washington, DC: U.S. Government Printing Office, February 1991), p. 105.

[55] U.S. Energy Information Administration op. cit., footnote 1, p. 9.

[56] Solar Energy Research Institute, op. cit., footnote 53, p. A-1.

[57] Ibid., p A-3.

[58] Ibid., pp. A-3, A-4.

plants. Hydropower facilities are characterized by low annual operating costs, long service lives, and low emissions of pollutants. Hydropower facilities can also aid flood control and provide recreation.

On the other hand, hydropower entails high initial capital costs, potentially serious environmental issues (e.g., aquatic life considerations and the loss of farmlands, wetlands, and scenic areas), dam safety concerns, and keen competition by other interests for use of the water base.

*Technical Opportunities-Several* areas of research promise to improve the economics of hydropower development and reduce its environmental drawbacks. For example, research on hydroturbines has resulted in technologies that may prove quite beneficial to hydropower development. A variable-speed, constant-frequency generator has been designed to alter the turbine speed in response to changes in the hydraulic head, allowing the turbine to operate at maximum efficiency.

New ultralow-head turbines, designed for use at sites with elevation differentials of less than 10 feet, could provide nearly 4,000 MW of additional capacity.[59]

Large-scale deployment of free-flow turbines for use in flowing rivers could help develop an additional 12.5 GW of capacity.[60] Use of such turbines would entail very little civil work, no impoundment of water, little disruption of flow, and no costly upgrade of dam structures.

The development of cross-flow turbines that optimize air injection and suction head in the draft tube and the design of replacement turbine runners with improved efficiency and air ingestion capabilities offer additional savings.

Further research is needed to identify and mitigate the environmental impacts of hydropower. Of particular interest are technologies to: 1) allow fish migrating downstream to bypass dams (upstream bypasses are reliable technologies), 2) specify instream flow requirement for aquatic life, and 3) quantify the cumulative impacts of multiple-site development of a river basin.

### Biomass[61]

Biomass already is a significant source of renewable energy. It is the only nonfossil liquid fuel for transportation applications. The industrial sector uses 2 quads of energy from biomass, almost all of it in the pulp, paper and lumber industries. Many of these industries use biomass in the cogeneration of heat and electricity. Furniture manufacturers and food processors are other significant users. The residential sector uses nearly 1 quad of firewood, mostly for space heating and cooking.[62]

*Biomass Resources—The* energy potential of biomass is enormous. DOE estimates a total energy potential of at least 55 quads in 2000, under certain conditions. Present capacity, excluding cultivated energy crops and wood and grain not used for biomass, is estimated to be 14 quads.[63]

*Energy* Crops—hardwood trees and herbaceous crops dedicated as energy resources-are the greatest potential source of biomass. The goal of providing a year-round, abundant supply of biomass is being supported by genetic engineering efforts and breeding research to increase yields and reduce costs of plants such as corn, sorghum, 'energy' cane, and short-rotation hardwoods. DOE reports that during the next 25 years, average annual crop yields are expected to be 5 to 11 dry tons per acre. At 9 dry tons per acre, the use of 192 million acres of potential cropland could generate a gross biomass energy capacity of 26 quads. It is not known at this time how many acres could be devoted to energy crop production without having a major impact on other" crops and forest production. Currently, about 900 million acres are classified as cropland or commercial forestland. Of that total, about 10 percent is withheld from production to either reduce crop productivity or for soil conservation purposes. An average of 328 million acres are planted annually.[64]

59 Oak Ridge National Laboratory, op. cit., footnote 4, p. 80.

60 Ibid.

61 Biomass refers t. materials from biological sources that can be converted to fuel or feedstock: wood and wood wastes, residues from processing food and wood products, agricultural wastes, sewage and municipal solid wastes, aquatic plants and algae, and "energy crops" grown specifically to provide fuel or feedstock.

62 Solar Energy Research Institute, op. cit., footnote 53, p. B-8.

63 Ibid., p. B-17.

64 Ibid., pp. B-5, 6.

Other sources of biomass are described below:

- *Conventional wood resources,* includes wood not used by the forest products industry in the thinning out of commercial forests. SERI estimates that conventional wood resources, if managed properly, could supply 6.5 quads of energy annually.[65]
- *Agricultural and forestry wastes* include primary and secondary residues. Primary residues are the stalks, limbs, bark, and leaves left on the land after harvesting. Expensive to collect, they are often left to enrich the soil. Secondary wastes emanate from processing (e.g., rice hulls, black liquor from pulping) and can often be used as fuel at little or no cost.
- *Agricultural oil seed crops* that produce vegetable oil offer an interesting but not yet commercial source of energy. Soybeans, which dominate this market, produce oil that is almost totally usable as fuel, yet soybean products are valued more highly for other uses. Rapeseed oil is a promising energy source.
- Certain *aquatic energy crops* produce oil that with upgrading could substitute for jet and diesel fuel. These plants include microalgae and macroalgae (e.g., kelp, cattails, water hyacinths, and spartina).

Biomass offers many environmental benefits. Carbon dioxide produced during combustion is balanced by reabsorption by the growing plants. Emissions of $SO_x$ and other air pollutants are negligible or at least as easily controlled as those from fossil fuels.

Although abundant, biomass resources are thinly dispersed. Collecting and transporting biomass to conversion centers can be costly, considering its relatively low ratio of energy content to weight. If biomass is to become a major source of economical energy, additional crops will have to be grown that are more productive, less costly, and sited closer to conversion centers. Gearing up energy crop production will entail greater land and water use, with various impacts according to locale. Recent advances in biotechnology can improve plant productivity and develop new plants. For example, productivity can now be increased 5 to 10 times over the natural growth rate of trees.[66] However, the increase in biotechnology and genetic engineering efforts will have to satisfy concerns of public and environmental safety.

*Converting Biomass to* Energy—Biomass can be used directly as fuel or converted to other forms for use as fuel or feedstock. Ultimately, biomass will be more useful if converted to gaseous or liquid fuels, but the conversion process can cost as much as the collection of biomass and feedstock production.

*Thermal Use of Biomass—The* principal energy use of biomass is the production of heat, via direct combustion in air, for use in process heating, space heating, and cogeneration systems. About 64 percent of this energy is used by the lumber, pulp, and paper industries. Homeowners and commercial entities use the rest.

Electricity is produced primarily through the direct combustion of wood, wood wastes, and wood byproducts. Most users of biomass for power generation are nonutility generators (NUGs) that have ready access to wastes or byproducts at little or no cost. Many utilities, however, purchase power from cogenerators who use biomass as fuel. In 1989, biomass-fueled capacity accounted for about 20 percent of total NUG capacity (40,267 MW). Biomass capacity included agricultural waste, municipal solid waste, and wood.[67] Utilities now operate wood-fired powerplants in California, Maine, Michigan, Oregon, Vermont, Washington, and Wisconsin. About 5,200 MW of total utility capacity is wood-fired.[68]

The use of biomass by utilities is usually uneconomical and impractical. Biomass has a lower energy content than coal, and delivery costs are higher because of the dispersed nature of the resource. Generally, biomass must be procured within a 50-mile radius of the powerplant to be economical. EPRI estimates that the costs of producing electricity from a wood-fired plant is 11 cents/kWh compared to 7 cents/kWh for coal-freed plants.[69]

‘Ibid., B-5.

[66]Oak Ridge National Laboratory, op. cit., footnote 4, p. 84.

[67]Edison Electric Institute, 1989 *Capacity and Generation of Non-Utility Sources of Energy,* April 1991, p. 9.

[68]Electric Power Research Institute, *Technical Brief,* ‘‘Wood—America’s *Renewable* Fuel,’’ RP2612-12, 1990.

[69]Ibid.

*Gasification of Biomass-The* production of methane (essentially natural gas) from biomass for supply to a natural gas system is accomplished by biological anaerobic digestion. Anaerobic digestion is particularly well-suited for very wet feedstocks and has been used commercially when biomass costs are low enough. Given a feedstock cost of $2.00/MBtu, methane can be produced for $4.50/MBtu, a cost not yet competitive with conventional natural gas unless other factors such as disposal costs are considered.[70]

Methane production from landfills, sewage treatment, and farm wastes will continue to increase but will be important only for specific locales. Biomass can also be converted by partial oxidation to syngas, which can be used as a fuel or as a feedstock for methanol production.

*Production of Biofuels*[71]*—A* variety of liquid fuels and blending components can be produced from biomass for use primarily in transportation. These biofuels include alcohol fuels (ethanol and methanol), as well as synthetic gasoline, jet, and diesel fuel.

Each year nearly 1 billion gallons of ethanol are added to U.S. gasoline stocks to create gasohol, a 90-percent gasoline/10-percent ethanol blend. The use of ethanol has gained support because of its potential contribution to the U.S. agricultural economy. The Federal Government and about one-third of the States subsidize ethanol use by partly exempting gasohol from gasoline taxes. Without these subsidies, ethanol would not be competitive with gasoline. OTA estimates that the full cost of producing ethanol ranges from $0.85 to $1.50/gallon, compared to wholesale gasoline prices of about $0.55/gallon.

Corn is the least expensive agricultural feedstock for ethanol production, especially when the byproduct of the production process can be sold. Wood and plant wastes are less expensive feedstocks, but the costs of available conversion processes are higher so that the net cost of producing ethanol from wood and plant wastes is more expensive than ethanol from corn. SERI is working on improving wood-to-ethanol processes and indicates that economic competitiveness can be reached by the year 2000.

Methanol can also be made from wood and other biomass materials, but the costs of production are uncertain. The National Research Council estimated that the crude oil equivalent price of methanol produced from wood, using demonstrated (not yet commercial) technology, is over $70/barrel. For biomass-based methanol to be competitive with coal-based methanol, improvements are needed in conversion technology and all aspects of growing and harvesting of biomass feedstocks. SERI expects the wood-to-methanol process to be ready for demonstration on a commercial scale by 2000 at the current R&D pace.

The production of diesel and jet fuel from microalgae is not as promising for the near term. Organisms with high growth rates that produce high oil content must first be developed. In addition, demonstration ponds must be built and operated on a large scale to make this process economical.

Converting biomass to synthetic hydrocarbon fuels through pyrolysis (thermal decomposition in the absence of air) of the biomass and catalytic upgrading of the biocrude to gasoline has been demonstrated in pilot plants but not developed for commercial use. Research results suggest a current cost estimate of the pyrolysis process to be $1.60/gallon for gasoline. A target of 85 cents/gallon is expected by 2005 if improvements are made in catalytic conversion and if feedstock costs are $2.00/MBtu.[72]

Commercial production of synthetic gasoline from biomass depends on improvements in the efficiency of the fast pyrolysis process. Specific needs include an increase in the yield and quality of the hydrocarbons produced. SERI expects that by 2020, fast pyrolysis technology should be commercially feasible at current levels of R&D.[73]

### Geothermal Energy

Resources of natural heat below the Earth's surface can be used directly for space and process heat or converted to electricity. Although the actual

[70] Solar Energy Research Institute, op. cit., footnote 53, p. B-7.

71 For a more indepth discussion of alternative fuels, see the OTA report *Replacing Gasoline—Alternative Fuels for Light-Duty Vehicles*, OTA-E-364 (Washington, DC: U.S. Government Printing Office, September 1990).

[72] Solar Energy Research Institute, op. cit., footnote 53, p. B-7.

[73] Ibid., p. B-16.

resource is enormous-potentially 10 million quads[74] in the United States alone-the amount that can be recovered economically is small. Nevertheless, using available technology, about 23,000 MW of capacity from geothermal resources could be tapped over the next 30 years, according to the U.S. Geological Survey.[75] In 1989, the U.S. geothermal industry produced 2.8 billion kWh.[76] Modest technical advances could dramatically increase the use of this resource.

Geothermal resources take several forms: steam, hot water, volcanic magma, hot dry rock, and geopressured brines. Except for brines located along the Gulf Coast, most of these resources underlie the western third of the country.

*The Resource Base—The geothermal* resource base includes usable heat contained within the Earth to a depth of about 3,000 feet.[77] Only 3.8 percent of this resource comes from *hydrothermal* reservoirs, naturally occurring hot water or steam at temperatures of 90 degree C. or more to a depth of 900 feet.[78]

Only a small portion of the hydrothermal resource is composed of the very hot (150 degree Celsius and more) vapor-dominated reservoirs used to generate electricity. Two-thirds of identified hydrothermal resources are in the moderate range of 70 to 121 degrees Celsius.[79] These resources and those that are of lower temperature show promise of recovery using available improved hydrothermal technologies.

The largest part of the geothermal resource base is found in: 1) magma, accessible regions of molten rock at temperatures of 850 degrees Celsius and higher; and 2) hot dry rock (HDR)--deep, hot regions of rock that can potentially be fractured by fluid pressure to create manmade reservoirs. No commercial recovery of either resource yet occurs. Likewise, energy from the geopressured-geothermal resource-zones of hot brine containing dissolved methane-that occurs mainly along the Gulf Coast has yet to be recovered.

*Converting Geothermal Energy-Converting* geothermal resources to energy entails bringing the resource to the Earth's surface via a production well and then converting geothermal energy to useful energy.

The technology for converting hydrothermal resources is well established. Dry natural steam can be converted to electric power by conventional turbine generators. Flash and binary cycle conversion technologies must be used to convert other geothermal resources. Flash steam technology is used with high-temperature liquids (less than 200 degrees Celsius) to produce steam to drive a turbine-generator. Binary cycle systems use the heat of a geothermal liquid to vaporize a second, working fluid. These systems are used when liquids are not hot enough (below 200 degrees Celsius) for flash steam approaches.

Although there has been little commercial experience with this technology, the dual-flash system is expected to be more efficient than the single-flash system now in extensive use. Dual-flash units are projected to be about 40 to 50 MWe in size by 1995.[80]

The binary cycle system is more complicated and costly because it uses a secondary working fluid, thus entailing special turbines and heat exchangers. Binary systems have an advantage in that the working fluid can have thermodynamic characteristics superior to steam, resulting in a more efficient cycle. Moreover, binary cycles operate efficiently at a wide range of plant sizes.

These same conversion systems used for hydrothermal resources can be adapted for recovering energy from geopressured zones, hot dry rock, and magma. Geopressured-geothermal resources can produce electricity at projected power costs of 7.5 to 16 cents/kWh, not counting the value of the natural gas byproduct.[81]

[74] Office of Technology Assessment, op. cit., footnote 27, P. 96.

[75] Solar Energy Research Institute, op. cit., footnote 53, p. C-1.

[76] U.S. Energy Information Administration, op. cit., footnote 1, pp. 201-239.

[77] Ibid.

[78] Office of Technology Assessment, op. cit., footnote 27, P. 96.

[79] Ibid.

[80] Ibid., p. 98.

[81] Solar Energy Research Institute, op. cit., footnote 53, P. C-3.

Hot dry rock technologies offer great promise for commercially developing the large geothermal resource potential. The rock is fractured to create reservoirs into which water is pumped. Once heated, the water is brought back to the surface, where its heat can be used directly or converted to electricity. With the needed technology developed, this method is projected to generate power at 5 cents/kWh.[82]

The heat from magma is recovered by pumping water into the subsurface to extract heat. Field experiments to confirm drilling techniques, reservoir dynamics, and other parameters are needed before this technology can become commercial. Magma energy costs are estimated to be 4.5 to 8 cents/kWh.[83]

The costs of identifying and developing geothermal resources are high. Improved technology for resource exploration and reservoir conflation could reduce costs as much as 25 to 40 percent for advanced concepts.[84] Moreover, predictions of reservoir performance must be enhanced.

Substantial cost reductions could also be made in drilling, completing, and operating geothermal wells. Accelerated research is needed on high-temperature equipment and corrosion-resistant materials. Savings of 15 to 20 percent for hydrothermal technology and 25 to 40 percent for advanced concepts could result. However, environmental issues, such as wildlife management and scenic considerations could restrict the development of some geothermal sites. SERI points out that the ''not-in-my-backyard' syndrome is just as true for geothermal projects as it is for other energy facilities.[85]

## Solar Thermal Electricity

Solar thermal electric plants use mirrors or lenses to concentrate sunlight, heating a fluid which is then used to produce electricity. Solar thermal systems operating with storage or with another fuel system offer significant potential for meeting peak or intermediate utility needs. Solar thermal electric plants produce 0.01 quad per year.[86]

Much progress has been made in the technology in the last decade. Several different solar thermal systems can produce electricity for about 12 to 15 cents/kWh. The DOE program goal is to produce electricity for 5 cents/kWh.[87]

Three technologies could be deployed competitively in the next 20 years: central receivers; and two distributed, or modular concepts, parabolic troughs and parabolic dishes.

Distributed systems have been more successful than central receivers. Since each unit is independent, it is easier to install. Each central receiver, however, must be designed for a specific number of heliostats (the concentrators). Heliostats must be individually focused on the central receiver and must follow a unique tracking system. However, it is not yet clear which concept will be superior in the long term.

*Central Receivers—The* central receiver is a freed receiver mounted on a tower. At its base a large field of mirrors, known as heliostats, tracks the sun, reflecting solar energy onto the receiver. The mirrors must move both vertically and horizontally on a precisely determined path. Liquid or air inside the receiver transports the thermal energy to a steam-driven turbine for generating electricity. In the 1970s, several solar thermal electric plants were built, including the 1O-MW Solar One Plant located in Dagett, California. The 30-MW Phoebus project in Jordan is the major central receiver project today .88

The most dramatic advances for central receivers have been in heliostat design and in the fluids used in the receiver. The most promise is seen in replacing the glass and metal mirrors in heliostats with stretched membranes of aluminum or steel sheets that are silvered on one face and curved to reflect solar energy at the right angle. Stressed membranes are about 20 percent of the weight of glass/metal

[82]Ibid.

[83]Ibid.

'Ibid., p. C-5.

[85]Ibid.

[86]Ibid, p. E-3.

[87]Oak Ridge National Laboratory, op. cit., footnote 4, p. 105.

88&l J. Weinberg and Robert H. Williams, "Energy From the Sun,'' Scientific *American*, March 1990, vol. 263, No. 3, p. 149.

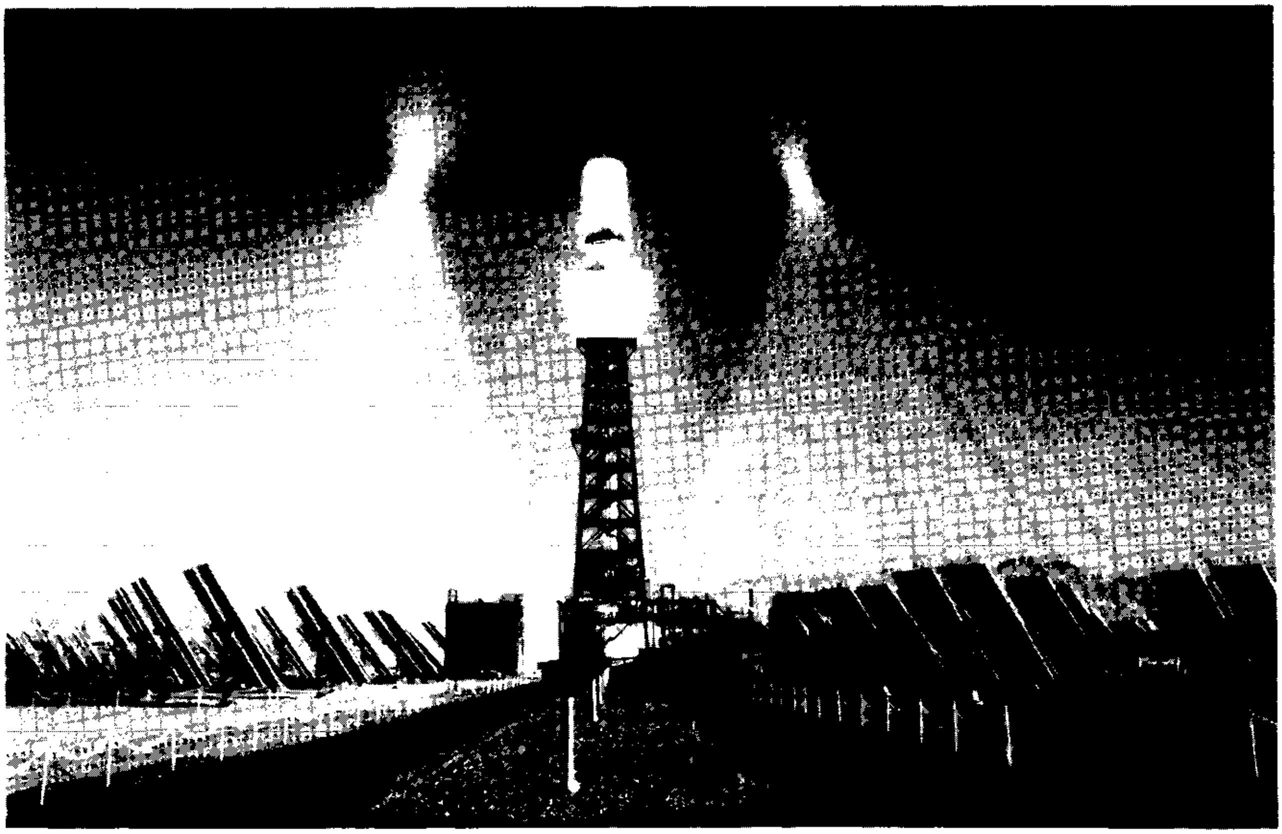


Photo credit: Southern California Edison Co.

The Solar One powerplant.

mirrors, which reduces the cost of the heliostat as well as the foundation and control system.

Research is also focused on replacing the steam/water in central receivers with molten nitrate salt. Molten salt can be maintained at lower pressures than steam (reducing pipe costs), and it stores heat well (reducing the need for heat exchangers or secondary systems). Storing several hours' worth of full power would allow complete load following in the summer when air conditioning peaks in the late afternoon.

Recent utility studies project annual central receiver system efficiencies of 14 to 15 percent, with costs of 8 to 12 cents/kWh for a next-generation plant using advanced receiver and heliostat technologies.[89]

*Parabolic Dishes—A* parabolic dish is a dish-shaped collector with a receiver mounted at its focal point near the center. Each module includes a two-axis tracking device. Several dishes are usually arrayed on a field, forming a distributed system. The concentrated heat may be used directly by a heat engine placed at the focal point, or may be transported by a fluid or air for remote use. Some designs use an array of mirrors, like a minicentral receiver.

New materials are being sought to replace traditional reflecting surfaces on the dishes. Of most interest is a stretched membrane of polymer. Other materials include large metal mirrors, mirrors incorporating structural support, and Fresnel lenses.

The most efficient system tested incorporates a free-piston Stirling engine at the focal point. About 30 percent of insolation can be converted to electricity by such a system, which is higher than any other

[89]Solar Energy Research Institute, op. cit., footnote 53, p. E-1.

solar electric technology.[90] The Stirling engine could be very reliable because of its mechanical simplicity, but it will need further development to improve its efficiency and cost.

Power costs from a system of stretched membrane dishes and a Stirling engine are projected to be 5 cents/kWh when commercially available.[91]

*Parabolic Solar Troughs-Collectively,* parabolic solar trough systems account for more than 90 percent of the world's solar electric capacity. A parabolic trough tracks the Sun vertically, which is simpler than the vertical and horizontal tracking required from heliostats and parabolic dishes. The trough concentrates sunlight onto a tube fried with fluid, usually very hot oil, at its focal line. The fluid circulates between troughs, finally transferring its heat through a heat exchanger to water or steam destined for a turbine generator.

Standing alone, solar troughs are best used for industrial applications. For electric power generation, supplemental gas-fired superheaters are used to create steam hot enough to drive a turbine.

From 1984 to 1988 several commercial solar trough plants, totaling 275 MWe, were built by the LUZ Corp. in California. LUZ is presently constructing 80 MWe of capacity, and is planning for 300-MWe additional capacity by 1994. These parabolic trough electric plants operate in the hybrid mode, using natural gas. Improvements in engineering, manufacturing, and construction techniques have reduced electric costs from 23 cents/kWh in early plants[92] to 8 cents/kWh in 1990. These are average costs, including the contribution of natural gas, which is cheaper than the solar portion.[93] Company officials at Southern California Edison project further system cost reductions of 30 percent,[94] which would make solar trough systems competitive in a wider range of markets.

*Industry* Outlook-solar thermal energy will not likely be a competitive baseload energy source unless oil and gas prices rise significantly.[95] Although no major breakthroughs are envisioned that would lower costs below current projections, these reductions may be enough to make solar thermal a valuable source of supplemental energy. One market for which it maybe uniquely qualified is toxic waste neutralization, where photochemical effects maybe more effective than simple heat.

For the near term, the solar trough/natural gas hybrid system appears to be the most marketable. Utility studies suggest that in the long term central receiver and parabolic dish technologies offer the most cost-competitive generation if cost-effective storage technologies can be developed. The U.S. budget for solar thermal research, however, has steadily declined in the last 10 years, and the United States has lost its leadership to European countries in marketing solar thermal technology to foreign markets. Besides its environmental benefits, developing solar thermal energy technologies offers a potential multibillion-dollar domestic and international industry.

### Photovoltaic Energy

Photovoltaic (PV) cells, which directly convert sunlight to electric current, have been used for years in calculators, watches, and space satellites. Other niche markets such as remote sites are also developing. These applications have sustained the PV industry while the technology has developed for using PV cells economically in the bulk power market. Although PV energy is more expensive than conventional energy for most uses, costs continue to drop. The present cost is now 20 to 30 cents/kWh—about five times the cost of conventional electricity.[96] With further advances in microelectronics and semiconductors, photovoltaics can become competitive with conventional power sources by 2010, maybe earlier. Some PV cells have already reached efficiencies of nearly 30 percent.

To capture solar energy, PV cells are grouped together in modules that are then linked in arrays on a large panel oriented toward the Sun. PV systems are used with battery storage in locations far from

[90] Oak Ridge National Laboratory, op. cit., footnote 4, p. 105.
[91] Solar Energy Research Institute, op. cit., foonote 53, p. E-2.
[92] Weinberg and Williams, op. cit., footnote 88, p. 149.
[93] Solar Energy Research Institute, op. cit., footnote 53, p. E-1.
[94] Weinberg and Williams, op. cit., footnote 88, p. 149.
[95] Oak Ridge National Laboratory, op. cit., footnote 4, p. 105.
[96] Weinberg and Williams, op. cit., footnote 88, p. 149.

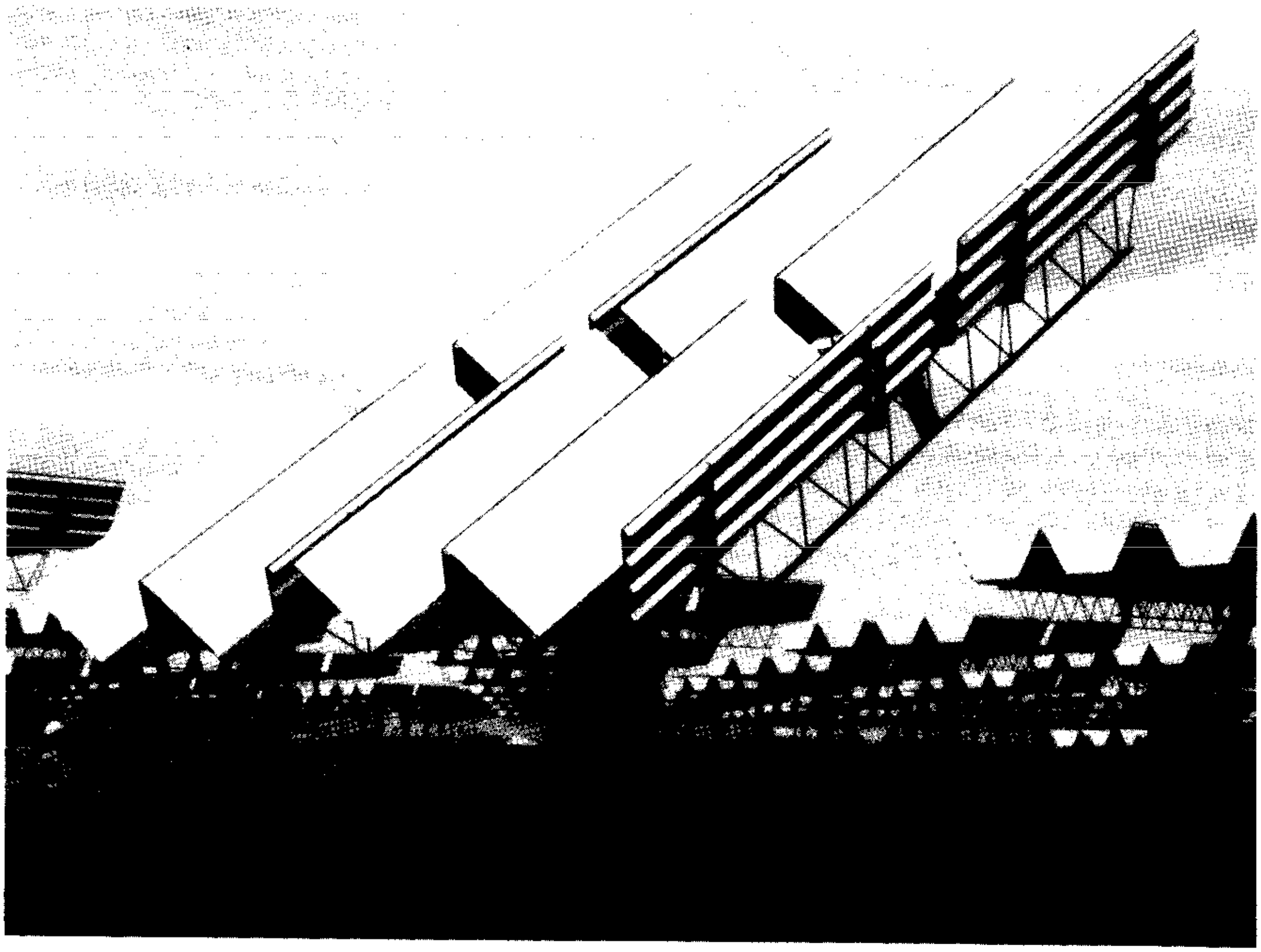


Photo credit:ARCO Solar, k

Photovoltaic central station,

existing powerlines. The direct current electricity produced can be converted to alternating current and fed into the electric grid, but this is not yet cost-effective.

Technology advances have been focused on two types of PV module systems: the concentrator system and the flat-plate collector. Each system uses a variety of materials and configurations.

*Concentrator Systems—In* a concentrator system, lenses focus sunlight onto PV cells so that the equivalent of 50 to 1,000 Suns are focused on each PV cell. Such a system requires direct sunlight and uses expensive, though highly efficient, cells along with an inexpensive concentrator. A fairly complex, two-axis tracking system maximizes Sun exposure. At very high Sun concentrations, active cooling with circulating fluids is necessary.

The concentrator module could be the technology of choice for central station use in the near term because this option involves fewer materials possibilities. Moreover, the most promising advances for this system have been improvements in solar cell efficiency.

*Technical Opportunities—Two semiconductor* materials are being considered for near-term concentrator systems: silicon (Si) and gallium arsenide (GaAs). Silicon is the most mature PV technology. Improvements in silicon cells will involve incremental advances and improved mass production rather than basic technical advances.

Unlike silicon, GaAs does not degrade much at high temperatures, a significant consideration for use at 500 to 1,000 Suns, where active cooling can be necessary. Furthermore, only a few microns of

GaAs are enough to absorb all the solar radiation, whereas a few hundred microns of single crystal silicon (c-Si) are needed for the same job. However, growing thin films of GaAs in the quantity and quality needed is not yet feasible.

Concentrators that keep optical losses small and maintain focused radiation on cells throughout wind stress, thermal cycling, and tracking are the central focus of R&D programs. In the near term, 20-percent efficient concentrator modules can be achieved.[97]

*Flat-Plate Collectors—This type* of PV module system exposes a large surface area of interconnected arrays of PV cell modules to the Sun. This system uses cells cheaper but less efficient than those in the concentrator system. Unlike the concentrator system, flat-plate collectors can operate in diffuse sunlight, and no cooling system is required. Very little maintenance is required.

Flat-plate systems entail a large number of interconnections between a large number of cells. The integrity of these connections, and their protection against hostile elements in the environment, are more important than the protection of the cells themselves. Making cells as large as possible reduces the number of interconnections.

*Technical Opportunities—Minimizing cell* cost is critical for flat-plate modules. The complex design and manufacturing process for highly efficient concentrator cells may always be prohibitively expensive for one-Sun use. Focusing R&D efforts on improving automated high-yield processing of one-Sun cells may be more fruitful than changing cell design itself. Improvements in the quality of solar cell grade Si may also be possible.

A variety of cells can be used in flat-plate systems. They include single crystal, polycrystalline and ribbon silicon, and amorphous silicon.

*Single Crystal Cells—The* expense of growing and slicing single-crystal cells makes it unlikely that such cells will be used extensively in flat-plate technology. Other forms of silicon and new processing technologies are the best hope for improving flat-plate technology .98

*Polycrystalline and Ribbon Silicon-Casting processes* yielding large-grained polycrystalline silicon and techniques for making continuously pulled ribbon silicon may yield acceptable efficiencies at significantly reduced cost.

*Thin-film Technology--The* cheapest approach to PV energy conversion is the deposition of thin semiconductor films on low-cost substrates. Thin films are amenable to mass production and use only a small amount of active material. Materials used include copper iridium diselenide, cadmium telluride (with small-area laboratory cell efficiencies of 19 percent), and amorphous silicon.[99] To be effective, deposition techniques must be developed to ensure high-quality and defect-he material within individual grains. If the thin film is polycrystalline, grain boundary effects must be minimized.

Amorphous silicon (a-Si) is interesting because only a thin film of inexpensive material is needed for high absorption and because large-area films of a-Si and multifunction a-Si cells can be made easily. However, efficiency is low and degrades over time. Research is focusing on improving efficiency by measures such as stacking cells (multifunction cells).

### Wind Power

Wind power is the solar energy technology closest to being economically competitive in the bulk power market. In 1989, wind powerplants generated over 2 billion kWh of electricity,[100] at an average of 8 cents/kWh. At the best sites the cost was only 5 cents/kWh.[101]

Wind turbines convert the energy of the wind to rotating shaft power, which is converted to electrical energy. Horizontal axis wind turbines capture wind via propellerlike blades attached to a rotor mounted on a tower, similar in appearance to windmills of old. Vertical axis wind turbines look like giant eggbeaters: their two or three long, curved blades are attached to a vertical shaft at both ends. These turbines require no orientation to catch the flow of wind from any direction.

~@& Ridge National Laboratory, op. cit., footnote 4, p. 121.

‘Ibid., p. 117.

[99]Ibid., p. 118.

[100]Solar Energy Research Institute, op. cit., footnote 53, p. 8.

[101]Jeanine Anderson, “New Third,” *Public Power*, vol. 8, No. 3, May-June 1990, p. 23.

Wind is an intermittent resource that varies from region to region. Sites with small differences in wind velocity have great differences in energy output, because power output increases with the cube of the wind speed. Thus, an average wind speed of 19 miles per hour (mph) will produce 212 percent more available energy than will an average speed of 13 mph. [102]

*Technical Opportunities-Although the* costs of wind-derived energy have dropped dramatically since 1981, few of these reductions stemmed from technological improvements. Most of the savings resulted from standardization of procedures, mass production techniques, improvements in siting, and the scheduling of maintenance for periods of low wind.[103] New turbines are now able to remain in operation almost 95 percent of the time.[104] In addition, the lifetime of critical components for wind turbines has doubled in the last 10 years.[105]

DOE and industry analysts agree that within the next 20 years expected improvements in wind power system design will yield electric power at 3.5 cents/kWh for sites with only moderate wind resources.[106] Some Midwestern States, with average wind speeds of 14 to 16 mph, would be likely beneficiaries of such technology.

Additional improvements will derive from more sophisticated turbines that can adapt to the changing speed and direction of the wind, thereby helping provide more constant frequency power to a utility. Pacific Gas and Electric and EPRI are engaged in a 5-year project to develop, build, and test prototypes of a 300-kW variable-speed, wind turbine whose blades and electronic controls allow the rotor to turn an optimum speed under a variety of wind conditions. Advances in electronic controls that are sensitive to changing wind characteristics, and advanced materials that yield lighter, stronger components are expected to further improve wind energy competitiveness.

Wind power sites must have adequate wind, suitable topography, accessibility to both utility and transportation systems, and acceptability from environmental, regulatory, and public perception perspectives. Characterizing a site has proven costly and time-consuming, because techniques for extrapolating data from one site to another are not yet refined. Extensive, customized wind measurements are necessary at most sites to estimate and maximize their full potential. There is a need to establish a coordinated program for integrating, documenting, and disseminating wind measurements on a constant, long-term basis.

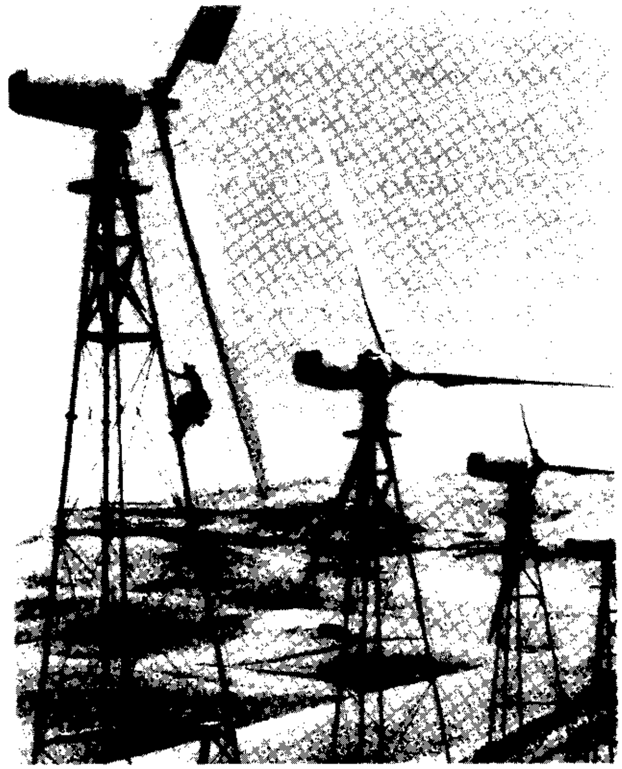


*Photo credit: U.S. Wn@ower, Ed Linton, photographer*

Small wind turbines.

In the past decade, U.S. funding for wind energy research dropped to $9 million per year, a tenth of what it was at its peak.[107] Technical improvements will be necessary if wind turbines, particularly small turbines, can compete without subsidies. More detailed information is also needed about wind

[102] Solar Energy Research Institute, Op. cit., footnote 53, p. F-1.
[103] Weinberg and Williams, op. cit., footnote 88, pp. 147-148.
[104] Solar Energy Research Institute, op. cit., footnote 53, p. 8.
[105] Anderson, op. cit., footnote 101, p. 26.
[106] Weinberg and Williams, op. cit., footnote 88, p. 148.
[107] Anderson, op. cit., footnote 101, p. 26.

resources, cost, and performance. Many industry observers recommend establishing minimum performance standard levels for turbine certification.

In general, improvements in wind energy are expected to continue, and the cost of electric power from wind turbines in high-wind regions may become considerably lower than power from other sources. The rate of improvement will be heavily influenced by future trends in the avoided costs or "buy-back rates" offered by utilities to nonutility energy producers. If these costs are low or uncertain, technological development and application will be slowed. Conversely, high avoided costs, stimulated perhaps by rising oil and gas prices or shrinking reserve margins of generating capacity, might considerably accelerate the contribution of wind power.

## Ocean Energy Systems

The ocean—with its waves, tides, temperature gradations, marine biomass, and other dynamic characteristics-contains an enormous amount of energy. Exploiting this resource has proved difficult.

ocean thermal energy conversion (OTEC) exploits the difference between temperatures of surface water and water as deep as 1,000 m[108] to generate electricity. Differences as small as 20 degree Celsius can produce usable energy. Tapping this vast resource, particularly in tropical oceans, would produce an estimated 10 million megawatts of baseload power, according to SERI.[109]

Research has focused mainly on the closed-cycle and open-cycle OTEC systems for generating electricity. The closed-cycle system recirculates a working fluid, like ammonia, to power a vapor turbine for electricity generation. Warm seawater is used to vaporize the ammonia via a heat exchanger (evaporator). The expansion of the vapor runs the turbine. Cold, deep-sea water than condenses the vapor via another heat exchanger (condenser).

An open-cycle system uses warm seawater that is flashed into steam in a partial vacuum chamber as the working fluid to power a low-pressure steam turbine. The steam exiting the turbine is condensed by cold seawater. If a surface condenser is used, the condensed steam stays separate from the seawater, providing desalinated water. Effluents from either open- or closed-cycle systems can be converted to freshwater through a second stage evaporator/ condenser system.

No commercial OTEC plants have been tested, but under some conditions, OTEC-derived electricity may be competitive in the next 5 to 10 years for small islands where power from diesel generators is very expensive. Use of OTEC domestically for electric power is unlikely except for coastal areas around the Gulf of Mexico and Hawaii.

It should also be noted that the basic OTEC technology-the conversion of large quantities of heat at low temperature differences to electric power--can also be used to exploit waste heat at industrial and commercial facilities. Many refineries, steel plants, chemical processing plants, etc. dump heat at much higher temperatures than are available in the ocean. Exploiting this energy would be much easier than building and operating an OTEC and would supply power right at a load center instead of out in the ocean. Similarly, thermal powerplants exhaust a huge amount of energy (60 to 70 percent of all energy input to the plant), though at lower temperature differences. A bottoming cycle using OTEC-type cycles could make an asset out of an environmental problem, and feed the power directly into the grid. Both these applications are likely to be economical long before OTEC.

Other ocean energy technologies that convert wave energy and tidal power receive much less attention than OTEC. The U.S. Government does no major wave R&D, but Norway, Britain, and Japan do. The greatest U.S. wave energy potential, with an estimated mean incident energy of 40 to 50 kW/m, is found on the West Coast. Wave energy during winter storms can reach over 200 kW/m, causing safety and design problems. Major technical challenges requiring engineering evaluations and development involve offshore siting (waves dissipate closer to shore), structural difficulties, the mooring, and the power transmission cable. Estimates for wave power for the Pacific Northwest are a yearly average power level of 1.64 MW, but a peak power of more than 3.3 MW during Winter.[110]

108The measure m is the difference between high and low tides, which creates a hydrostatic head like that in hydropower.

109Solar Energy Research Institute, op. cit., footnote 53, p. D-1.

110Ibid., p. D-9.

111Ibid.

The total U.S. tide potential has been estimated at 18,300 GW.[111] Only three coastal areas, however, are promising: one in Maine and two in Alaska. a minimum tidal range of 5 m is needed for tidal power to be considered practical. Research in microhydro technology may make tidal systems feasible at lesser tidal levels.

### Municipal Solid Wastes (MSW)

About two-thirds of the solid waste generated by households and by commercial, industrial, and institutional operations is burnable and can be converted to energy.

*Conversion Technologies—MSW can* be converted to electricity and process heat by either mass combustion or refuse-derived fuel combustion. In mass combustion, MSW is burned with or without pretreatment or sorting of the inherent waste products. In refuse-derived fuel combustion, recyclable materials and noncombustible materials are frost removed from the MSW. The remaining material is made into pellets.

Waste-to-energy facilities function much like a fossil fuel steamplant. The fuel is burned to heat water, and the steam drives a turbine to generate electricity. The steam can also be used in district heating/cooling systems. SERI estimates that current use of MSW for electricity totals 0.11 quads. Under current programs, that amount is expected to rise to 0.45 quads by 2010 and 0.57 quads if R&D is increased.[112] Most waste-fired capacity is owned by nonutility generators.

Another energy product, methane, can be recovered from MSW for use in natural gas systems via the anaerobic digestion of MSW's digestible components. If the cost of MSW disposal exceeds $40/ton, the net cost of MSW-derived methane may be as low as $3.50/MBtu, making it nearly competitive with the cost of delivering natural gas to the cities.[113]

A less economic recovery of methane is possible from the natural decomposition of MSW in landfills. Currently, 0.01 quad of landfill methane is recovered.[114] For safety reasons, other methane is collected from landfills and flared, because the volume is too low to be economical.

Several problems exist with present MSW approaches. MSW plants have higher capital and operating expenses than those of wood- or fossil-fired plants, mainly due to feedstock processing costs and to later emissions and solid waste disposal.

Some of these costs are balanced by credits for avoiding MSW disposal. Thus, overall costs of power generation average 7 cents/kWh but could alter depending on the economics of particular locales.115

A variety of technology improvements are being sought for reducing the costs of electric power generation and emission control, increasing the attractiveness of MSW as a fuel for electric power-plants. New ways are needed to dispose of dioxins, nitrogen oxides, chlorinated gases, solid residues, and ash. Automatic trash sorting to remove glass, plastics, and other recyclable would improve combustion and reduce disposal problems.

For methane production by anaerobic digestion of MSW, improvements are needed in solids loading rates and digestion efficiency. Also needed are improvements in the stability and control of digester operation. An accelerated program with industry involvement and cost-sharing could reach performance goals if tipping fees for MSW exceed the $25 to $50/ton range.[116]

Extensive commercial use of gasification of MSW may be economical already in areas where disposal costs are high (where tipping fees are above $100/ton at lanfills).

## OTHER FACTORS AFFECTING SUPPLY

### *Environmental Concerns*

Perhaps of greatest concern is the greenhouse effect produced by gases emitted during fossil fuel combustion. These greenhouse gases, which include $C0_2$, methane, $NO_x$, and chlorofluorocarbons, trap heat in the atmosphere preventing its radiation into

[112]Ibid., p. B-20.
[113]Ibid., p. B-7.
[114]Ibid., p. B-8.
[115]Ibid., p. B-6.
[116]Ibid., p. B-11.

space. Global temperatures could increase by 2 to 9 degrees Fahrenheit over the next century if current emission trends continue. The anticipated rise in temperature could lead to devastating changes in climate, agriculture and forestry, and population shifts.

The United States is a major contributor to greenhouse gas emissions. U.S. carbon emissions from energy use account for 25 percent of the world total. Coal accounts for 35 percent of U.S. carbon emissions; petroleum, about 45 percent; and natural gas, about 18 percent.

A recent OTA report, *Changing by Degrees: Steps To Reduce Greenhouse Gases,* concluded that the United States can reduce $CO_2$ emissions by 20 to 35 percent from 1987 levels over the next 25 years but only with great difficulty. There are significant opportunities for reducing $CO_2$ emissions in all sectors. To achieve this reduction, a serious commitment and the implementation of a variety of technical options and policy measures will be required. Emissions reductions may be costly, but no major technological breakthroughs are needed.

The implementation of $C0_2$ reduction measures will have far-reaching effects on the U.S. economy and energy supply picture. The switch to low or noncarbon fuels may revitalize the nuclear option, increase demand for natural gas, accelerate the growth of renewable, and limit production and consumption of coal. Attempts to limit coal use will result in significant social and economic impacts. At the very least, marginal, inefficient mines and coal-fired powerplants will probably close. Unemployment in the coal industry will rise. This will exacerbate economic problems that already beset some coal mining regions, especially Appalachia. Nevertheless, if we are serious about reducing $CO_2$ emissions, coal is the place to start.

The increased use of natural gas can deplete U.S. reserves and strain the distribution system. Prices could rise to very high levels. Also, the increased use of natural gas carries with it the risk of increased methane leakages.

These reduction measures will also result in ancillary environmental benefits that include reducing acid rain, urban smog, ozone depletion, groundwater contamination, and waste disposal. All of these environmental concerns can be addressed or are being addressed by regulations, so the advantages may be marginal. For an indepth analysis of technical and policy opportunities for reducing greenhouse gas emissions over the next 25 years, the reader is referred to the recent OTA report *Changing By Degrees: Steps To Reduce Greenhouse Gases.*

Another environmental concern is acid rain. The combustion of fossil fuels also produces sulfur dioxide and nitrogen oxide. As these pollutants are carried away from their sources, they can be transformed through complex chemical processes into secondary pollutants: sulfates and nitrates. These pollutants combine with water to form acid and fall as rain or other precipitation. Numerous chemical reactions-not all of which are completely understood-and prevailing weather patterns affect the overall distribution of acid deposition.

The best documented and understood effects of acid deposition are to aquatic ecosystems. The sensitivity of a lake or stream to acid deposition depends largely on the ability of the soil and bedrock in the surrounding watershed to neutralize acid. When the waters of a lake or stream become more acidic than about pH 5, many species of fish die and the ecosystem changes dramatically. In addition to the acidification of aquatic ecosystems, transported air pollutants have been linked to harmful effects to terrestrial ecosystems. Broad forested areas subjected to elevated levels of acid deposition, ozone, or both have been marked by declining productivity and dying trees, although it is uncertain how much of this is due to airborne pollutants. For an indepth discussion of acid rain, the reader is referred to the OTA report *Acid Rain and Transported Air Pollutants: Implications for Public Policy.*

*The* new Clean Air Act of 1990 caps utility emissions of $SO_2$ by the year 2000 at 8.9 million tons per year, a 10-million-ton reduction from 1980 levels. The new law also requires annual reductions of nitrogen oxides. Midwestern utilities and those located in Appalachia will be hardest hit by the cap. Most of the heaviest polluters are located in these regions. The biggest cuts in the first 5 years will be made by the heavy polluters. In addition, the law provides for a pollution credits trading system, which helps polluting utilities pay for acid rain cleanup. Utilities can reduce $SO_2$ emissions below their required limit-receive credits. These credits can be sold to other utilities and the cash used to defray costs of emissions control technologies. Credits are also given to "clean" utilities to grow beyond the cap.

The mandated emissions reductions will likely result in increased electricity costs to consumers, particularly in the Midwest, and may financially strain certain vulnerable utilities. Markets may be disrupted by an increase in the demand for low-sulfur coal at the expense of high-sulfur coals. This change in demand will result in increased unemployment in regions where high-sulfur coal is mined. The extent to which utility and industrial users would shift to low-sulfur coal depends on the relative cost advantage of fuel switching as opposed to removing sulfur dioxide by technological means (scrubbers). It is hoped that by providing financial incentives (pollution credits) to defray the costs of pollution control equipment, utilities will not switch to low-sulfur coal and thus save some high-sulfur coal-mining jobs.

## *Obstacles to a Nuclear Revival*

### Public Acceptance of Nuclear Power

Over the years, public concerns about reactor safety, costs, and waste disposal have had an impact on nuclear power will affect energy supply options in the future. The accidents at Three Mile Island and Chernobyl dramatized the hazards of nuclear power. Poor operations at some plants, especially when mishaps or small radioactive releases occur, serve as reminders. Nuclear reactors present risks to the public that are statistically much lower than other commonly accepted facilities such as dams, but the public will not find that credible until safety is no longer a controversial issue. Critics are unlikely to let the controversy die down as long as major accidents cannot be incontrovertibly proved to be of vanishingly small probability. Under present conditions, the public sees little reason to accept a potential risk for uncertain gains.

Utilities are very concerned over public acceptance of nuclear power. Recent public opinion polls have shown a resurgence in the fraction of people believing that nuclear energy will be essential. However, these polls do not tell the whole story since they ask questions only about general approval or disapproval. If a specific site were proposed for a nuclear powerplant, it is likely that the majority of people in the region would be opposed. Furthermore, public support would have to be widespread and with only minor opposition before utilities could be confident that there would be no reversal during construction and the operating lifetime of the plant.

There are many ways in which the public can make its opposition felt. Most directly, referenda have been held to shut down nuclear plants. One has passed on the Rancho Seco Plant in California, though that seems to have been more related to the economics of a poorly operated plant than to concerns over safety. Indirectly, the public also exerts pressure in courts, on local governments that must issue permits, and on state governments which must regulate rates of return on the investment and approve emergency evacuation plans.

At this point it is simply not possible to say with any assurance whether there will be a nuclear revival or what it would take to initiate one. If there is one, it will occur primarily because new plants are safer and cheaper than has been the recent norm and because alternatives are proving inadequate. However, neither safety nor cost will be easy to establish.

If costs and safety of nuclear power can be convincingly made favorable relative to other choices, a revival is quite possible, though by no means assured. This will not happen within the next few years, but by the mid-1990s demand growth is likely to mandate considerable new construction, and the industry will have had time to replace the memories of the present failures with a period of reliable operation and declining costs. Under such conditions, having the option of an economical reactor that has been thoroughly reviewed to minimize the risk of cost escalation or operating problems could prove attractive.

### Financial Risks

The investment community provides another important disincentive for nuclear power. Investors generally believe nuclear to be much riskier than other options, based on the tribulations of utilities such as Public Service of New Hampshire, Long Island Lighting, the Washington Public Power Supply System, and General Public Utilities. Traditionally, regulated utilities provided limited profits, but also low risks. Some utilities have found their massive investments to be useless when they could not finish a plant because it proved to be unnecessary or too expensive, or failed to get a license, or were shut down for safety inadequacies. Some investors now refuse to buy stock or bonds in a utility building a nuclear plant, while others demand a large risk premium.

Very few people involved in operating nuclear powerplants believe that nuclear plants represent a significant hazard to the public, but failed construction projects and plants damaged by moderately serious accidents, e.g., Three Mile Island, pose important financial risks for the utility.

*Capital Costs—A* recent industry study predicted that a new nuclear plant would cost $1,400/kWe compared to $1,220 for a coal plant and $520 for a gas combined cycle plant. The levelized costs for the power would be 4.3 cents/kWh for nuclear, 4.8 for coal, and 6.1 for gas.[117] These figures are not verifiable because no plant has been started recently or under the conditions assumed in the analysis. In addition, industry has been generally optimistic on cost estimation, sometimes spectacularly so. Nevertheless, it suggests that nuclear power can still be competitive if the problems of the past can be avoided.

### Nuclear Waste Disposal

Concerns about nuclear waste disposal also will have an effect on energy supply adequacy. The lack of proven technology and a known site for safely sequestering nuclear wastes has been one of the major factors behind opposition to nuclear power. To many people, it seems irresponsible to build reactors before we could be sure that waste products would never be a threat. The period required before the radioactivity of spent fuel decays to completely innocuous levels[118] is many times longer than recorded history, and no one can envision all the problems that might arise so far in the future. The many false starts, delays, and problems that have been encountered in the program to develop a nuclear waste disposal facility underscore the uncertainty of success.

Nuclear proponents point out that the need for waste disposal has always been recognized, and that the technical problems are not as formidable as they appear. Nuclear wastes are difficult to contain because they generate heat. The short- and mid-term components that produce almost all the heat largely decay within 200 years. After 1,000 years, virtually no radioactive material is left but plutonium and traces of a few other long-lived components. The waste can be stored in geological formations that have been stable for many millions of years, and even if conditions change, any leakage will be very slow (the long-lived wastes are largely insoluble in water and too heavy to be easily windblown). Such leakage should pose essentially no threat to people or the environment, especially in comparison to chemical wastes and other risks. In any case, the problem must be solved whether we build more reactors or not, because of all the waste that has been produced already in the commercial and weapons programs.

Yucca Mountain, part of the Nevada Test Site for nuclear weapons, has been selected as the site for the first Federal high-level waste repository. The climate is extremely dry, and the water table is about 1,000 feet below the proposed waste storage level, limiting the likelihood of leaching. The area is very thinly unpopulated, minimizing the number of people who could be at risk. Extensive testing and detailed analyses necessary to validate this selection are underway.

In addition to the natural protection of deep burial in a stable formation with little groundwater seeping down through the site, various manmade barriers will be applied to ensure protection, especially during the earlier, rapid decay rate stages. Waste can be blended into material, e.g., borosilicate glass, which hardens into a very stable mass. Vitrified wastes (or spent fuel) can also be encased in casks made of materials impervious to any plausible chemical or mechanical agent.

Other sites and different geological formations are probably also feasible. Yucca Mountain was chosen as much for political reasons as for technical.[119] Proposed nuclear waste disposal sites engender intense opposition (though sometimes also local support for the considerable economic benefits they can offer) which may be out of proportion to the risk entailed but can be just as difficult to overcome. Most experts are confident that nuclear waste can be safely contained, but a great many people are unwilling

[117] U.S. Council for Energy Awareness, "Advanced Design Nuclear Energy Plants: Competitive, Economical Electricity," January 1991.

[118] Plutonium has a half-life of about 24,)()() years, and about eight half-lives or 200,000 years are required to reduce the radioactivity to the level of the original ore.

[119] Luther J. Carter, *Nuclear Imperatives and Public Trust* (Washington, DC: Resources for the Future, 1987).

to accept these assurances. The risks to the local population are small, but they are not zero. Careless practices in the past that resulted in releases of radioactivity, and false starts such as the proposed site at Lyons, Kansas, ensure that the public will not blindly rely on the experts. Siting will be much easier if the program can establish a reputation for fairness and responsiveness to local needs. More high-level disposal sites will be needed, especially if nuclear power is to grow.

Disposal of intermediate and low-level radioactive wastes may prove to be more troublesome in the long run because the volumes of materials are very much larger and the number of disposal facilities to be licensed and monitored is much greater. However, much of this material comes from research or medical purposes, not nuclear powerplants. Thus it is imperative to solve the problem whether or not nuclear power resumes growth.

### *Electric and Magnetic Fields*

If electric and magnetic fields do prove to pose a risk to human health, the implications for the electric power industry will be great. Already, health effects are one of the most prominent concerns raised by people living near existing or proposed transmission lines. Several States have experienced increasing pressure to take regulatory action to protect citizens from the possible hazards posed by power frequency fields. By January 1989, seven States (Montana, Minnesota, New Jersey, New York, North Dakota, Oregon, and Florida) had already set limits on the intensity of electric fields around powerlines. Florida is the only State to adopt standards to limit the amount of both electric and magnetic fields.

Most of what we know today about the effects of exposure to these fields comes from three types of studies or experiments: Cell-level experiments, whole animal experiments, and epidemiological studies. Until relatively recently, there was little or no scientific evidence that electric and magnetic power frequency fields could pose a threat to human health. However, laboratory studies have now demonstrated that fields have effects on living cells and systems. Scientists are still investigating whether these effects have public health implications. In addition, several recent epidemiologic studies have suggested an association between exposure to power frequency fields and cancer. While these epidemiologic studies are controversial and incomplete, they do provide a basis for concern about the effects from exposure.

The research results to date are complex and inconclusive. Many experiments have found no differences in biological systems that have been exposed to fields and those that have not. It still is not possible to demonstrate that such risks exist, and they may not. However, the emerging evidence no longer allows one to conclude that there are no risks.

It is important to remember that exposure from transmission lines is one perhaps minor source. Exposure to local electric distribution lines, appliances, lighting fixtures, and wall wiring are more common and could play a more significant role in any public health risks. The OTA background paper *Biological Effects of Power Frequency Electric and Magnetic Fields* provides an indepth review of existing scientific evidence on biological effects and discusses policy responses to risk management.

### *Electricity Demand Uncertainty*

Major shifts in electric power usage patterns have bedeviled utility planners and energy forecasters since events of the 1970s and 1980s made previous assumptions about inflation, consumer behavior, and economic growth obsolete. Throughout the past decade, the electric power industry has been saddled with expensive excess capacity as powerplants ordered in the 1970s came on line and demand growth fell below expectations. In the 1990s, the industry's problems with excess capacity appear to be receding, and in some regions of the country, reserve margins are tightening to the point that some industry analysts are warning of shortages.

overall reserve margins are expected to decrease over the next 10 years. One of the results of lower capacity margins is that some utilities will have less flexibility in dealing with more severe situations. Another result could be greater reliance on older units, which in turn will increase maintenance requirements and result in more outage time. A number of factors could easily change supply adequacy or excess capacity into a shortage situation. Among the most important of these are delayed capacity additions and higher than predicted growth rates.

Among the analysts that have examined these prospects, there is some disagreement about when and where additional generation is needed. The disagreements are rooted in uncertainty over future growth in demand and the cost and performance of existing and planned capacity. In the face of the considerable uncertainties, conflicting views about which risks to take and who must bear those risks are inevitable. In recent years, few utilities have been willing to commit to construction of new baseload capacity, in spite of the continued aging of the existing generating plant stock and predictions from some industry and government planners that the country faces possible shortages in the early to mid- 1990s. Meanwhile, the flow of new plant additions by utilities entering service as a result of orders placed in the 1970s is slowing to a trickle, although capacity additions by nonutility generators are increasing.

### Nonutility Generation

Increases in nonutility generating capacity have been significant in recent years. The growth in cogeneration and small power production facilities has, to some extent, offset the slowing of utility construction of new capacity. According to the Edison Electric Institute, electricity sales to utilities from nonutility sources increased sixfold from 1979 to 1986 and 33 percent in 1988 and 1989.[120] Almost all of the sales have been to the investor-owned segment of the industry.

Also, nonutility generation is an important source of electricity in some States (California, Louisiana, Texas, Maine, Alaska, Hawaii) and is starting to become a national factor. Moreover, several regions, including New England and the Mid-Atlantic, will increasingly depend on nonutility generation additions to ensure supply adequacy or offset capacity shortfalls over the next 10 years.

A wide range of technologies can be used to cogenerate electric and thermal energy, e.g., steam turbines, open-cycle combustion turbines, combined cycle systems, and diesels. Much of the investment in new generating technologies, particularly cogeneration, has come from nonutility generators. For more information about cogeneration technologies, the reader is referred to the OTA report *Industrial and Commercial Cogeneration.*

[120] Edison Electric Institute, op. cit., footnote 65.