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Since its creation in 1933, the Tennessee Valley Authority (TVA) has evolved into the largest steam coal consumer and electric power producer in the Nation. If present plans are completed, it will also be the largest producer of nuclear power. This report, which is the first major review of TVA's power program since 1959, assesses TVA's energy-related problems in terms of numerous national policies related to energy conservation, demand management, expanded use of coal, growth of nuclear power, increased use of renewable resources, and maintenance of environmental quality. Findings/Conclusions: TVA needs different programs and priorities if it is to reflect national energy goals and continue its role as an energy leader and yardstick. Recommendations: In order to improve TVA's planning and decision-making process and to provide criteria by which TVA can be better evaluated, TVA should: (1) prepare a long-range comprehensive plan (minimum of 25 years) with specific short-term goals to be presented to the President and the Congress; (2) prepare several 25-year electricity demand projections emphasizing energy conservation and the use of renewable resources; (3) collect more detailed information on all users and uses of electricity; and (4) undertake a variety of energy supply and demand alternatives which should be included in the comprehensive plan. The Congress should revise TVA's charter to charge the authority with leading electricity-management plans and programs development, encouraging energy conservation and efficient production and use of energy, encouraging renewable resources use, and assuring adequate public involvement in energy planning and policymaking. (Author/SC)

BY THE COMPTROLLER GENERAL

Report To The Congress

OF THE UNITED STATES

8444

Electric Energy Options Hold Great Promise For The Tennessee Valley Authority

Since 1933, the Tennessee Valley Authority has evolved from a multipurpose regional development agency with incidental electric power generation into the largest steam coal consumer and electric power producer. If present plans are completed it will be the largest producer of nuclear power.

This report, the first major review of TVA's power program since 1959, assesses TVA's energy related problems in terms of numerous national policies related to:

- energy conservation,
- demand management,
- expanded use of coal,
- growth of nuclear power,
- increased use of renewable resources, and
- maintenance of environmental quality.

GAO recommends a number of energy supply and demand options that TVA should pursue as a leader of the electric industry.

The Congress should revise TVA's charter to charge the authority with leading electricity management plans and programs development, encouraging energy conservation and efficient production and use of energy, encouraging renewable resources use, and assuring adequate public involvement in energy planning and policymaking.

UNITED STATES GENERAL ACCOUNTING OFFICE

EMD-78-91

NOVEMBER 29, 1978

COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

B-114850

To the President of the Senate and the
Speaker of the House of Representatives

This report recommends many energy supply and demand options that the Tennessee Valley Authority (TVA) should pursue as a leader of the electricity sector. TVA is currently revising its policies and undertaking new programs that reestablish its leadership role. We fully support these actions and would expect that TVA's renewed effort, together with this report, will benefit both the region and the Nation in helping to solve energy-related problems.

To accomplish these goals, we recommend that TVA's charter be revised to charge it with (1) leading electricity management plans and programs development, (2) encouraging energy conservation and the most efficient production and use of energy, (3) encouraging the use of renewable resources, and (4) assuring adequate public involvement in energy planning and policymaking.

We made our review pursuant to the Budget and Accounting Act, 1921 (31 U.S.C. 53) and the Accounting and Auditing Act of 1950 (31 U.S.C. 67).

We are sending copies of this report to the Director, Office of Management and Budget; the Secretary of Energy; the Board of Directors, TVA; Members of Congress; the House and Senate Committees having oversight and appropriation responsibilities for TVA; the House Ad Hoc Committee on Energy; and the Senate Committee on Energy and Natural Resources.

Comptroller General
of the United States

COMPTROLLER GENERAL'S
REPORT TO THE CONGRESS

ELECTRIC ENERGY OPTIONS HOLD GREAT PROMISE FOR THE TENNESSEE VALLEY AUTHORITY

D I G E S T

With the United States involved in an escalating energy problem, this report considers the Tennessee Valley Authority's (TVA's) energy-related issues in the context of its traditional role as an energy leader and supplier of electricity. They are assessed in terms of national policies related to

--energy conservation,

--demand management,

--expanded use of coal,

--growth of nuclear power,

--increased use of renewable resources, and

--maintenance of environmental quality.

The report also discusses options TVA can pursue by undertaking various programs to illustrate their advantages and disadvantages. If the options proposed were to become reality, changes in TVA's charter and its planning system would be required.

CONCLUSIONS

TVA needs different programs and priorities if it is to reflect national energy goals and continue its role from its creation in 1933 as an energy leader and yardstick.

In order to meet electrical demand in the region it serves, TVA has, and is constructing, large central station production units. The region's power needs through the year 2000 could be met with the completion of these plants, coupled with energy conservation, improved power management, and the use of renewable resources. Therefore, time could be allowed for evaluation, development, and testing of alternative options before making additional commitments to large central station units.

There is a critical need for a comprehensive, long-range TVA power program plan extending at least 25 years. TVA's planning has been almost entirely dependent on a single demand forecast for a 15-year period. But this was based on inaccurate and incomplete data, implied that future electricity growth is predetermined when considerable influence is possible, and could not reflect alternative assumptions such as differing real price effects and other variables affecting demand.

Several demand forecasts as a part of a formal long-range plan could help eliminate conflicts in missions and overlapping of services by managers and directors. It could provide goals and priorities and establish a means by which TVA could be evaluated and held accountable.

Such a plan could assess optional courses of action from both a cost-effectiveness viewpoint and in terms of TVA's yardstick function.

The formal plan could be reviewed by as wide a spectrum of regional citizens and institutions as practicable and their comments considered in arriving at a final version. In particular, the Department of Energy's review and comment would be critical to assure consistency with national priorities. TVA could include Energy's comments as an appendix to the final plan together with TVA's evaluation of those comments. When any option TVA selects is a research or development project that involves Federal funds, TVA should make sufficient details available at Energy's request.

TVA could submit the final comprehensive plan to the President and the Congress. GAO could evaluate the plan, monitor its implementation, and report to the President and the Congress periodically. The Congress then would be in a better position to plan hearings as needed.

This should result in better planning and a clear congressional mandate emphasizing the use of conservation and renewable resources.

ENERGY SUPPLY ALTERNATIVES

The following energy supply alternatives were evaluated as options TVA could pursue:

--Industrial cogeneration. Application of available cogeneration technologies and development of new ones by TVA could (1) provide hard data to establish expected high fuel efficiencies, (2) illustrate the benefits of utility-owned systems, (3) indicate the level of social benefits and consequent savings to consumers, and (4) reduce the uncertainty and unfamiliarity regarding cogeneration technology and fuel. The potential for the TVA region ranges from 5,200 to 6,700 megawatts by the year 2000.

--Flue gas desulfurization. Because TVA has agreed under proposed consent decrees to install scrubbers on 3,183 megawatts of its coal-fired units, it could pursue a scrubber program which experimented with an array of flue gas desulfurization systems. Pursuing such a program could exceed least cost strategies by about 7 percent and, therefore, the additional cost could be federally funded.

--Fluidized bed combustion. The future of coal-fired plants in the TVA region depends, to a large extent, on the commercial viability and acceptance of fluidized bed combustion systems in the 1990s. If TVA constructed commercial scale atmospheric fluidized bed combustion it could play a proper and vital role in demonstrating and in resolving the problems of this technology.

--Longwall mining. As the Nation's largest buyer of steam coal, TVA can encourage longwall mining of coal which is faster, cheaper, and safer than underground methods when ecological conditions are suitable. A TVA coal purchasing policy for various mines using

Tear Sheet

this technology could help overcome the high capital cost barriers.

If TVA takes the lead in demonstrating any supply alternatives, the Nation will benefit. Therefore, added costs over and above traditional power costs could be federally funded. These could be based simply on an analysis of TVA's incremental costs for new powerplant construction.

ENERGY DEMAND ALTERNATIVES

By exercising various demand alternatives, TVA could reduce the growth rate of energy demand, make the existing power system more efficient, and defer new generating systems.

Implementing the three residential National Energy Plan programs in the TVA region could save electricity and reduce energy-related costs in area households by as much as $90 million through 1990. (See p. 5-3.)

TVA also could expand its heat pump program to encourage heat pump installation in all new construction. If all electric heating systems installed in new residences were heat pumps, a net savings of $50 million through the year 1990 could be realized.

Electricity consumption is sensitive to price changes. A 1-percent increase in the real price of electricity could lead to as much as a 15.7-percent reduction in residential demand by 2000. If options discussed in the report and other TVA initiatives do not reduce demand adequately, TVA could effect additional conservation savings by applying a surcharge or issuing bonds that would result in similar effects. Money received could then be used as incentives to further conservation and the use of renewable resources.

The power management strategy GAO considered involves influencing electricity demand to maximize the use of base load plants and minimize the use of more expensive peaking generators. These included varying rates to reflect seasonal and time-of-day demands, developing interruptible contracts and services, and matching variable loads in commercial and industrial sectors. Implementing these options would reduce requirements for petroleum distillates, increase load factors on base and intermediate load plants, and lower overall power costs.

The use of solar energy through such applications as solar passive building design, solar water heating, and solar space heating could further reduce demand for electricity.

RECOMMENDATIONS TO THE BOARD OF DIRECTORS, TVA AND THE SECRETARY OF ENERGY

To improve TVA's planning and decisionmaking process and to provide criteria by which TVA can be better evaluated, GAO recommends that:

--TVA prepare a long-range comprehensive plan (minimum of 25 years) with specific short-term goals to be presented to the President and the Congress. This plan should be updated and submitted annually. TVA should obtain review of the draft plan from a wide spectrum of the regional population. The Department of Energy should review the plan to ensure that it reflects national priorities and does not duplicate research and development projects and TVA should include their comments as an appendix with an evaluation of those comments. GAO should evaluate the final plan, monitor its progress, and report to the President and the Congress periodically. The Congress would then be in a better position to plan any needed hearings.

--TVA should prepare several 25-year electricity demand projections emphasizing energy conservation and the use of renewable resources.

--TVA should collect more detailed information on all users and uses of electricity. For example, TVA should survey residential customers to determine patterns of ownership for major household equipment, appliances, and housing units and meter individual appliances in homes throughout the region.

TVA should undertake the following energy supply and demand alternatives, which should be included in the comprehensive plan.

ENERGY SUPPLY ALTERNATIVES

TVA should undertake a major application/demonstration of cogeneration technologies which could include:

--A coal-fired steam turbine system in the several tens of megawatt range.

--A gas turbine system in the 50-200 megawatts range capable of using alternative fuels (for example No. 6 oil, methanol, residual fuel oil, etc.) in a cogeneration mode.

--A gas turbine system capable of using different fuels and designed for installation at smaller industrial locations (to answer important questions on the economies of scale).

--A fluidized bed gas turbine system coal fired, coordinating its effort with the work of American Electric Power Company. In that company's system, steam from the gas turbine is run through a steam turbine to produce additional electricity. However, the TVA demonstration should be of a size to demonstrate the capacity of feeding excess generation to the network and simultaneously producing process steam for industry.

--A fluidized bed gas turbine system fired by biomass, in particular, wood waste. This demonstration could be located at a major wood and paper products complex such as the one in Calhoun, Tennessee. It would show fuel cycles and alternatives to coal and concentrate on industrial and agricultural wastes and perhaps municipal waste.

Federal funding should be requested for those demonstrations that exceed TVA's incremental cost per kilowatt.

TVA should continuously assess the potential for new industry cogeneration projects and support industries with such potential, particularly those in newly developed industrial parks.

In complying with the proposed consent decrees, TVA should follow the maximum demonstration and development of flue gas desulfurization technologies in its coal-fired units, as proposed in chapter 6. Such a program would cost more than simple compliance would require and would entail certain risk. We recommend, therefore, that TVA request an appropriation for this program for those costs over and above simple compliance.

TVA should construct commercial scale atmospheric fluidized bed combustion. Because of the risks inherent in this unproven technology, we recommend that this demonstration be funded the same as the cogeneration technologies above. Upon successful demonstration of this fluidized bed combustion, we recommend that it be used to meet all major TVA power production facilities required through the year 2000.

TVA's future coal purchasing policies should include actively pursuing contracts with coal mine operators who are using longwall mining techniques.

ENERGY DEMAND ALTERNATIVES

Although TVA has recently expanded its conservation and demand management programs, it should extend or undertake the following options:

--Increase efforts to implement the National Energy Plan programs.

--In conjunction with the education and certification of heat pump installation and maintenance, actively encourage installation of heat pumps in all new construction.

--Study and implement seasonal and time-of-day rates.

--Expand the use of interruptible contracts, but offer them on a regular interruption basis rather than an emergency.

--Initiate a program to switch off hot water heaters and larger air conditioners in peak hours.

--Evaluate and pursue opportunities for matching variable loads in the region.

To further decrease electricity demand, TVA should:

--Promote the use of solar passive building design with incentives such as design awards for builders similar to the heat pump and Super Saver home programs.

--Design a strategy similar to the above promotion for solar water heating. In addition, TVA should provide alternatives for making these systems economically competitive for the consumer (such as reduced rates) since they are less costly to the power system than adding new generation capacity.

--In coordination with the Department of Energy, participate in the research and development of solar space heating and cooling for applications in the region.

--If the above options and other TVA initiatives do not adequately reduce demand, TVA should consider applying a surcharge or issue bonds that would result in similar impacts to effect additional conservation savings. Money received should then be used as an incentive to further conservation and the use of renewable resources.

RECOMMENDATIONS TO THE CONGRESS

The Congress should revise TVA's charter to better reflect current national energy priorities. TVA should be charged with

--leading electricity management plans and programs development,

--encouraging energy conservation and the most efficient production and use of energy,

--encouraging the use of renewable resources, and

--assuring adequate public involvement in energy planning and policymaking.

GAO recommends that TVA request certain funds to demonstrate the energy supply projects GAO identified. The Congress should favorably consider those requests.

AGENCY COMMENTS

TVA is revising its policies and undertaking new programs that reestablish its leadership role in the electricity industry. GAO fully supports these efforts and would expect that TVA's renewed role, together with this report, will benefit both the region and the Nation in helping to solve energy-related problems.

Because of items pointed out by TVA and the Department of Energy, GAO revised the report where appropriate. Both TVA and Energy disagree with the need for a revised mandate for TVA at this time. A revised mandate is still recommended, however, because

--TVA's power program now represents over 90 percent of its total assets and its current mandate does not adequately reflect it's power functions and

--although TVA is pursuing the type of options proposed, a congressional affirmation through a new charter would affirm that TVA's programs remain in that direction. A revised charter would better reflect TVA's current and future power responsibilities as the priority it should be for both the the region and the Nation.

Contents

ABBREVIATIONS

AEP	American Electric Power
AMA	American Management Association
DOE	Department of Energy
EPA	Environmental Protection Agency
FBC	fluidized bed combustion
FGD	flue gas desulfurization
GAO	General Accounting Office
GNP	Gross National Product
GRP	Gross Regional Product
kWh	kilowatt hours
MMBTU	million British Thermal Units
MW	megawatts
NCUC	North Carolina Utilities Commission
NEP	National Energy Plan
NRC	Nuclear Regulatory Commission
OMB	Office of Management and Budget
ORNL	Oak Ridge National Laboratories
SIC	Standard Industrial Classification
SO	sulfur dioxide
TVA	Tennessee Valley Authority

CHAPTER 1

INTRODUCTION AND SCOPE

When the Tennessee Valley Authority (TVA) was created by the Congress as an independent Federal corporation in May 1933, the generation of electric power was considered incidental to navigation and flood control. TVA has, however, evolved into the Nation's greatest consumer of steam coal and the largest producer of electricity. If present plans are completed, it will become the largest producer of nuclear power. During the time of this planned conversion, and for an indefinite time thereafter, the United States will be involved in an escalating energy problem. This report examines TVA's responsibilities in terms of national energy goals. Specifically it

--describes the development of TVA's power program between 1933 and 1977,

--assesses its organizational structure, decisionmaking process, and accountability,

--evaluates its longer-range energy plans, and

--identifies and evaluates alternative energy policies.

TVA's energy-related programs are considered in the context of its traditional role as a yardstick supplier of electricity and its unique institutional position. They are assessed in terms of national policies governing conservation, the management of energy demand, the expanded use of coal, the growth of nuclear power, the increased use of renewable resources, and the maintenance of environmental quality. TVA's power program accounted for about 90 percent of its total assets for fiscal year 1977. We briefly examined the interrelationship between power and nonpower activities but did not evaluate its other programs.

NATIONAL ENERGY PERSPECTIVE

During the past four years, the United States has undergone an oil embargo by the Organization Of Petroleum Exporting Countries, and seen international oil prices increase by over 400 percent.

On April 20, 1977, the President addressed a Joint Session of Congress and presented the outline of a National Energy Plan. The Federal Government responded with new regulations, new programs, and new legislation, but the response has not been a clearly enunciated and cohesive national energy policy.

Basic problems remain unresolved. The Nation is more dependent upon foreign energy supplies today than it was 3 years ago, and many renewable energy sources have not been developed commercially at the maximum feasible rate.

In April 1977, the President chose TVA as a national energy demonstration agency. In August, the TVA Chairman of the Board sent the President proposals for specific energy development activities. Many were already underway, and the Chairman proposed to build on that base. He also suggested that TVA serve as a testing ground for energy projects developed in government and industry research programs.

ORGANIZATIONAL AND PROGRAM PERSPECTIVE

TVA is headed by a three-member Board of Directors, appointed to staggered 9-year terms by the President, with the advice and consent of the Senate. The President designates one member as Chairman. TVA's principal administrative officer, the General Manager, is responsible for carrying out Board policies, programs, and decisions.

TVA produces and distributes electricity to some 2.6 million customers, through 160 municipal and cooperative electric systems, in 7 States. It also serves directly 48 large industrial customers and several Federal installations. The Department of Energy's (DOE's) facilities in Oak Ridge, Tennessee, and Paducah, Kentucky, use about 20 percent of TVA's electrical production.

TVA's power operating revenues totaled $2.0 billion in fiscal year 1977. Power bonds and notes worth $5.9 billion were outstanding as of September 1977.

SCOPE OF REVIEW

In performing this study, we discussed energy development strategies with numerous Federal agencies including DOE and the Environmental Protection Agency (EPA). Although we met TVA representatives throughout the region, our primary field work was done at the TVA Office of Power in Chattanooga, Tennessee. We also met with representatives of various State agencies, utilities, coal mining associations, and other interest groups.

Our alternative demand projections and evaluations are based, in part, on information supplied by a varied group of consultants in the field of physics, economics, law, engineering, and finance.

In the following chapters, we provide a framework within which the likelihood and desirability of other possible futures for TVA can be assessed from a national as well as regional perspective.

CHAPTER 2

TVA's ORIGIN, EVOLUTION, AND CURRENT STATUS

The Tennessee Valley Authority was created in 1933 as a multipurpose regional development agency with missions involving flood control, fertilizer and economic development, improvement of navigation, and the incidental generation of electric power. The success with which TVA pursued these goals attracted world-wide attention to it as a model for developing countries. TVA is the Nation's largest generator of electricity, but some critics believe it has evolved into "just another power company."

CREATION AND ORIGINAL GOALS

On April 10, 1933, President Roosevelt asked the Congress to create "a corporation clothed with the power of government but possessed of the flexibility and initiative of a private enterprise." TVA began life as a corporation with the authority necessary to develop the resources of the Tennessee Valley and adjoining areas, free of the "strait-jacket" which sometimes enfolds the Federal bureaucracy.

The Congress stated its own clear intentions in the TVA Act. The preamble states:

> "To improve the navigability and to provide for the flood control of the Tennessee River; to provide for the reforestation and the proper use of marginal lands in the Tennessee Valley; to provide for the agricultural and industrial development of said Valley; to provide for the national defense by the creation of a corporation for the operation of Government properties at and near Muscle Shoals in the State of Alabama, and for other purposes."

The TVA Board was directed to regulate streamflow primarily to promote navigation and control flood, but also:

> "So far as may be consistent with such purposes * * * to provide and operate facilities for the generation of electric energy * * * in order to avoid the waste of water power * * * [and] * * * to assist in liquidating the cost or aid in the maintenance of the projects of the Authority." (16 U.S.C. 831 h-1)

The original goal of TVA power development was to upgrade an economically undeveloped region. A second goal, based on President Roosevelt's belief that the utility industry had been profiteering, was to establish a "yardstick" standard for evaluating the efficiency of private utilities. The Congress incorporated this principle in the Act (16 U.S.C. 831m), and ordered TVA to report complete information on true costs of producing and distributing electricity.

EVOLUTION OF THE POWER PROGRAM

Section 124 of the 1916 National Defense Act (formerly 50 U.S.C. 79, repealed in 1956) authorized the President to determine the best means for producing nitrates and to build dams and power equipment for that purpose. Two nitrate plants were built at Muscle Shoals and Wilson Dam; one of three dams planned by the Corps of Engineers, were completed by 1925.

Before TVA was created, various attempts were made to find a use for the Muscle Shoals plants. One offer, from Henry Ford, passed the House but was rejected by the Senate. Two development bills passed by both houses were vetoed by Presidents Coolidge and Hoover. Senator George Norris, by amending another bill, sought to create a Federal Chemical Corporation, with a three-man board, to manufacture and sell fertilizer, which also authorized building dams on the Tennessee River and its tributaries for navigation and power. Surplus power--that is, power not needed to produce fertilizer or explosives--was to be sold publicly with preference given to area municipalities. This amendment failed but it foreshadowed the TVA Act by almost 10 years and it described the principle of the Government sale of surplus power later upheld by the United States Supreme Court.

When President Franklin D. Roosevelt came to office in 1932, the principle of unified river management was already defined though there was considerable opposition to selling power in competition with private firms. President Roosevelt took the position pioneered by Senator Norris. On April 10, 1933, he said, in a brief message to the Congress:

> "It is clear that the Muscle Shoals development is but a small part of the potential public usefulness of the entire Tennessee River. Such use, if envisioned in its entirety, transcends mere power development; it enters the wide fields of flood control, soil erosion, afforestation, elimination from agricultural

use of marginal lands, and distribution and diversification of industry. In short, this power development of war days leads naturally to national planning for a complete river watershed involving many States and the future lives and welfare of millions. It touches and gives life to all forms of human concerns."

Although the Act of 1933 clearly put TVA in the electric power business, the Congress' intention concerning the scale of operations remained uncertain. It is difficult to determine precisely when electric power production began to dominate the organization.

In 1939, the Congress authorized TVA to issue bonds for the purchase of transmission facilities to serve 27 counties formerly served by the Alabama Power Company, expanding TVA's potential market. When World War II brought an enormous increase in demand for aluminum production to meet the goal of building 50,000 airplanes annually, TVA's capacity was greatly expanded. It was further expanded when the Manhattan Project began development of the atomic bomb at Oak Ridge, Tennessee.

TVA set new records in dam constuction to meet the power demand of the war effort. By mid-1942, TVA had 12 dams and a steam plant under construction and employment peaked at 42,000. One project which had a peacetime schedule of 5 or 6 years was completed in less than 3 years by TVA crews working around the clock. By fiscal 1945, TVA had increased its generating capacity from less than 2 billion kilowatt hours (kWh) in 1939 to nearly 12 billion kWh of electricity.

Seventy-five percent of TVA's power was used for defense and it was assumed the Valley would be vastly oversupplied after the war, but peacetime needs grew beyond the wartime levels. Industry moved into the region, residential and commercial use climbed, and the atomic installations at Oak Ridge and Paducah grew dramatically. Increasing power generation capacity became imperative, but the potential for further developing hydro-electric projects was relatively small. TVA turned to steam generation. After extensive hearings demonstrated TVA's inability to meet power demands without steam, the Congress approved construction of the Johnsonville Steam Plant, the first of many steam power facilities.

In 1958, TVA's proposals for steam plants raised concern in the private sector. After a year or more of intense debate, the Congress amended the TVA Act (16 U.S.C. 831n-4) to authorize public sale of electric power bonds. The amendment required repayments to the U.S. Treasury sufficient to provide an established return on the Federal investment. It also placed, for the first time, a legal restriction on the geographical area to be served by the TVA power system.

By the end of the 1950s TVA was generating nearly 60 billion kWh of electricity annually--4 times the amount of a decade earlier. During this same period, the average residential power rate dropped to less than half the national average.

During the 1960s, the demand for electricity continued to rise and the generating capacity was increased by about a million kilowatts a year. In 1967, TVA started construction of the world's largest thermal nuclear plant--Browns Ferry in northern Alabama--with a load capacity of nearly 3.5 million kilowatts. As of June 1978, six additional nuclear plants were under construction, or planned, to help meet the region's projected power demands through 1986.

The constitutionality of the TVA Act and the validity of the generation and sale of electric power by the Government have been challenged in a series of court cases, two of which eventually reached the U.S. Supreme Court. In a 1936 decision (297 U.S. 288), the Court held that the Government had the power to sell TVA electricity. It reasoned that the electric energy created by construction of dams was the property of the United States and the Government had power to dispose of that property in the public interest.

TVA's statutory authority to construct steam plants and connect tramsmission lines has been upheld under several separate provisions of the U.S. Constitution: the commerce clause (article I, section 8, clause 3), the war power and defense clauses (articles I and II) and the general welfare clause (article I, section 8, clause 1). TVA's resale rate provisions, its policy of direct sales to industry, and its power of condemnation have also been upheld.

INTERRELATIONSHIP OF POWER AND NONPOWER FUNCTIONS

The preamble of the TVA Act declared a congressional commitment "to improve the navigability and to provide for the flood control of the Tennessee River."

The act discussed a far-reaching program of fertilizer development. It made clear that a primary purpose of TVA was to promote the agricultural and industrial development of the Tennessee Valley, but did not specify the means. The amendments over the years have dealt primarily with the power programs.

The act also authorized TVA to undertake both regional and national programs of fertilizer development, and because there was only negligible effort in the private sector, TVA became and remains the national leader for research and development in fertilizer.

The TVA Act did not establish priorities for economic development of the region. Its lower than average industrial power rates and the Valley's ample water and transportation facilities have attracted industry. The region's industrial growth was about three times the national rate in the years 1958-72.

Within the context of its regional responsibilities, and in addition to its power development role, TVA has always carried on some general, developmental activities. The most noteworthy of these have been in the areas of recreation and community development, waste disposal, manpower training, and agriculture development.

The Congress made it clear that TVA was to operate the Government's properties at Muscle Shoals to promote the agricultural and industrial development of the Tennessee Valley. Although cheap and plentiful electric power aided this effort, some TVA supporters contend that recurring congressional references to the disposal of "surplus power" should make the "power program" subordinate to navigation, flood control, and fertilizer development. However, the production and sale of power have come to dominate program action if not program thinking in TVA and President Carter's request for TVA help was directed at the power program.

COMPARING TVA TO OTHER UTILITIES

The current energy problems and the recent recession have had a profound effect on the utility industry. Decreasing revenues and sharply increasing fuel prices have posed financial difficulties for many utilities.

Other uncertainties have emerged such as licensing delays, pollution controls, the rate of future demand growth, and financing availability, and these have forced many utilities to cancel or delay expansion plans. As a result, the Nation may face electricity shortages beginning in the 1980s.

TVA has been able to deal with these uncertainties primarily because its unique Federal status gives it the flexibility to enter contracts, reinvest revenues, issue bonds, and generally conduct its affairs as the Board of Director deems appropriate.

TVA is also exempt from most Federal, State, and local regulations, and it has not felt many of the financial and regulatory constraints plaguing many other utilities.

The Board of Directors can adjust rates without regulatory review and TVA has maintained the highest possible bond rating. It has access to the Federal Financing Bank, which private utilities do not. As of September 1977, TVA had $5.9 billion in outstanding debt. Of this amount, $3.9 billion had been sold to the Federal Financing Bank. TVA has been able to pursue a vigorous construction program to meet expected electricity demand.

CHAPTER 3

ORGANIZATION AND DECISIONMAKING PROCESS

The TVA Act gave the Board of Directors full responsibility for establishing " * * * a system of organization to fix responsibility and promote efficiency." The intent behind this broad authority was described in the 1933 Conference Committee:

> "We are fully persuaded that the full success of the Tennessee Valley development project will depend more upon the ability, vision, and executive capacity of the members of the board than upon legislative provisions. We have sought to set up a legislative framework, but not to encase it in a legislative straitjacket. We intend that the corporation shall have much of the essential freedom and elasticity of a private business corporation. We have indicated the course it shall take, but have not directed the particular steps it shall make." (H.R. Rep. No. 130, 73d Cong., 1st Sess. 19 (1933).

The President designates the Board chairman, but all three members are equal in voting power. From 1933 to 1938, the Board attempted a commission form of management with members assuming distinct functional duties. While substantial growth took place during these years, some observers believe Board discord nearly ruined the agency.

In 1938, President Roosevelt removed and replaced the Board chairman, and the Board withdrew from functional management and devoted itself to policy formulation. The Board does not have a formal staff directly responsible to it, however, the members do appoint a General Manager who has traditionally come up through the ranks.

THE GENERAL MANAGER

The duties of the General Manager have never been specifically defined by the Congress, but he has become a dominant infuence on TVA policies. He reviews all project authorizations and approves construction projects costing less than $1 million and research projects costing less than $200,000 without review. Proposed projects costing more than those figures are first reviewed by the General Manager, and if he approves them, are submitted to the Board.

The General Manager's responsibilities include executing programs, policies, and decisions adopted by the Board and approving major management methods, organizational changes within offices and divisions, and major staff appointments; reporting to the Board on overall efficiency and effectiveness of TVA operations; and assisting the Board in presenting the TVA budget to the Congress and the Office of Management and Budget (OMB).

The Agency's separate divisions have great measures of independence, but this has also led to problems of duplication and overlap. Division Directors have lacked overall priorities for specific programs because TVA has no comprehensive program definition. This is due to both administrative and political reasons unique to TVA's special Federal status.

OFFICE MANAGERS AND DIVISION DIRECTORS

TVA is divided into offices and divisions. The Office of Power is generally conceded to have the greatest influence on the Board. It operates the Nation's largest utility and controls about 90 percent of TVA's expenditures. It controls 14 of the top 35 administrative positions.

Office managers and division directors are chosen by the General Manager and approved by the Board of Directors. They have great independence and flexibility. Almost two-thirds of them have been appointed within the past 5 years, a situation precipitated by the retirement of executives who joined the Agency in the early 1930s. Two-thirds of the managers and directors have been with the Agency for more than 20 years. Only one top staff person in the Office of Power has worked for TVA for less than 25 years and only five of the Division Directors came from outside the Agency, of which four were recent appointments.

Disagreements are usually settled by the division directors and office managers or by their subordinates. When a difficulty cannot be resolved on the division/office level, the General Manager is notified.

PROGRAM DEFINITION AND REGIONAL PLANNING

Program definition is a chronic TVA problem. Sections 22 and 23 of the TVA Act gave the Agency broad powers for regional development, and the Congress appeared to believe that a master plan for the region might appropriately be developed.

In 1936, in response to a congressional mandate, TVA prepared a "Plan for the Unified Development of the Tennessee River Systems." It called for the improvement of navigation, the development of agricultural and industrial growth through rural electrification. These goals were substantially met during the next 10 years.

However, in a series of actions beginning in 1953, the TVA Board discarded preparation of a comprehensive regional plan and the 1936 effort remained the only unified plan ever developed by TVA.

In 1956, a group of 18 authorities associated with the Agency's development, provided an assessment of TVA's first 20 years. The review, edited by Professor Roscoe Morton, of Syracuse University, found:

> "The chief problem confronting the TVA is the persistent and pervasive issue of program definition. It would not be correct to consider this a new or emerging problem, for the whole history of TVA has been one of constant definition and redefinition of program. Nevertheless, it is incumbent upon the Board of Directors, at the end of 20 years, to take special note of the scope, depth, and balance of the program. Is it broad enough to serve the purpose for which the TVA was created? Does it cover the needs of the region, in terms appropriate to a regional authority? Do its various parts hang together logically or is it, as is sometimes charged, a patchwork program?"

There were both political and administrative reasons for avoiding comprehensive planning and pressures from the Congress and the executive branch that inhibited it. TVA encouraged decentralized planning instead and involved various State and local agencies and institutions in a general cooperative effort but its programs remained ill defined and no schedule of overall priorities was developed to which office and division managers could refer.

In 1969, the General Manager responded to divisional requests and hired an American Management Association (AMA) consultant to develop a TVA planning system. The AMA's recommendations, however, were generally ignored by TVA officials who considered them too academic and inconsistent with TVA's decentralized planning process. In 1971, TVA again confronted the problem and tried to develop a planning system which would be appropriate to its decentralized philosophy--but without much more success.

In 1975, TVA hired another consulting firm to evaluate its corporate planning process. Their report concluded that:

--Most TVA executives wanted more effective planning.

--Many directors thought the TVA planning staff should be working on long-range, Agency-wide goals.

--Approximately half of them felt that a document summarizing such an overall TVA plan would help them better manage their divisions.

--Several managers saw conflicts among TVA's missions and an overlapping of services.

--The performance of operations units is not evaluated in terms of specific plans.

The consulting firm further concluded that for an organization as complex as TVA, a set of overall, specific, and tangible goals was a necessary guide for lower and middle managers.

TVA'S CORPORATE PLANNING SYSTEM

TVA has a planning system that originates at staff level and involves the General Manager, but the Board has never formally endorsed it.

The system is a modified version of a conceptual model designed by G. A. Steiner, based on two approaches to planning: strategic and tactical. Strategic plans are conceived usually as long-range proposals made by top management with few details. Tactical plans comprise ones of short duration, which involve many managers and employees, and control the detailed use of resources.

No strategic planning

TVA does not have an overall strategic plan which considers different long-term scenarios of electricity demand and provides guidelines and priorities for the Agency's divisions. Its system does plan short-term projects.

In the absence of a strategic or long-term plan, TVA's managers are guided by the public speeches of Board members, Board reactions to staff proposals, and by a single demand forecast, which is prepared or amended annually and which attempts to calculate the fluctuations in demand for periods of 15 years. This document is well researched and carefully detailed, but it has serious flaws as a basic planning tool.

It is a "single" overall forecast and it is based on limited assumptions--a single real cost of electricity and a single rate of demand growth are assumed. If either or both of these basic assumptions proves inaccurate, the whole mechanism of scheduling construction and other power-related programs is affected.

A forecast which considered the demand consequences of variations in cost and demand growth would permit long-term planning that was both more economical and more efficient.

The lack of an adequate system of long-term planning has other undesirable results. Executives on the division and office levels do not have an overall plan into which they can fit their own projects in terms of overall agency and national energy goals. It is also difficult for executives below the top level to perceive variations in programs at an early point and to react quickly to changing conditions.

Tactical planning

TVA's decentralized management system places tactical responsibilities on the operating offices and divisions. The process begins at lower levels and culminates in a summary document prepared by the heads of offices and divisions for the General Manager. Each tactical planning paper includes

--a situation assessment,

--a summary planning document,

--a multiyear budget, and

--a program evaluation.

A planning and budget staff analyzes each for conformance with Board policies and consistency with other program goals. The General Manager and his staff members then have a corporate planning meeting with office and division heads and approve programs.

Office and division heads then incorporate the approved programs into their respective multiyear budgets. These budgets are then condensed into a single multiyear budget which is approved by the Board and submitted to the Office of Management and Budget in Washington.

All divisions and offices, except the Office of Power, project program plans at least 5 years; the Office of Power projects its activities for 15 years. OMB requires 5 year intervals to predict budget plans, but in scheduling power-plant construction as much as 15-years leadtime is required.

DEMAND FORECASTING

The demand forecast, which provides predictions of future electrical usage in the region, is the core of TVA's power program. Estimates of cost of operations and revenues from sales--the keys to TVA financial planning--are based on the forecasts. It also provides the basis for determining when, where, and what types of new generating facilities are needed, and for developing conservation and load management programs. The demand forecast is used in numerous internal planning documents and is submitted to other agencies, and used in reports to the Congress. TVA planning centers around TVA's demand forecast.

Forecasting electrical demand is, at best, an inexact science. Methodologies used vary from the simplistic to the sophisticated and the factors and values used vary among different service areas. Forecasters must rely on data in areas such as economic growth, fuel prices and availability, employment, and population shifts, on which many experts disagree.

Two recent documents offer glimpses of the future as seen by TVA. One is TVA's 1977 Load Forecast, which predicts power loads to the year 1992.* The other is a paper prepared by the TVA Office of Power in 1977, which discusses alternative scenarios of power consumption and makes projections to the year 2000. TVA expects the compound rate of growth of total power demand in the region,

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*It has been TVA's practice to prepare only one "official" load forecast.

excluding Federal Government purchases, to be approximately 5.7 percent a year reaching 344.1 kWh by the year 2000. Projected capacity by type, shifts heavily in favor of nuclear by the year 1986.

We have made two alternative demand projections for the TVA system and these are discussed in the following chapter. We also prepared a detailed analysis of TVA's load forecasting process which is included as appendix I.

CHAPTER 4

A PERSPECTIVE FOR LEADERSHIP BY TVA

In this and the following chapters, we discuss options TVA can pursue to meet its traditional goal of providing the region adequate electric power at the lowest feasible cost while, at the same time, serving the Nation by undertaking various programs to illustrate their advantages and/or disadvantages. In recent years, this latter function has diminished in importance with TVA operating much like any other power company.

To provide a context for this analysis, we assessed those options TVA could pursue and quantified those effects, where possible, on TVA's demand forecast* and on two alternative demand projects we prepared.

The various programs we considered for TVA's adoption included:

--Conservation and demand management options, particularly the setting of appliance efficiency standards, and the encouragement of weatherization, heat pumps, industrial cogeneration, and load management.

--A strategy for making coal more acceptable, specifically, flue gas desulfurization (FGD) options, fluidized bed combustion, and longwall mining.

--Solar energy applications for solar passive building design, such as solar water heating and solar space heating.

In quantifying these programs within the framework of TVA's and two alternative projections, we seek to provide plausible pictures of what the results might be if TVA put a new emphasis on national considerations. In the following chapters, we highlight options that are feasible and desirable on either an application or demonstration basis and make appropriate conclusions and recommendations. For purposes of this report, an option recommended for application is one found to be commercially available and cost effective. Those recommended for demonstration are not commercially available and ones which either are not currently cost effective or which entail high risks.

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*The TVA projections are based on TVA's July 1977 Load Forecast.

The data presented in this and subsequent chapters requires three qualifications. First, the effects are only potential and their realization would require action by TVA and other organizations. Second, the data presented reflects only the region's potential not the Nation's. Third, pending energy legislation may effect the impacts we quantified.

This chapter briefly discusses (1) the TVA forecast and our two alternative projections, (2) the supply strategies and their costs necessary to meet these projections, and (3) the effect of our proposed options on those projections. Appendix I discusses the TVA forecast in more detail and appendix II provides a technical description of our projections and their relation to TVA's.

HIGH AND LOW PROJECTIONS OF RESIDENTIAL DEMAND

We first offer a high baseline projection for the residential sector, based on the residential energy use model developed by Oak Ridge National Laboratory. It assumes*

--data on population, households, housing choices, fuel prices, and incomes similar to those used in TVA's forecast;

--no implementation of Government conservation programs, though it does consider certain voluntary household reactions and changes in new construction as the result of recent increases in the price of electricity;

--constant real price** of electricity through 2000; and

--an elasticity*** of electricity demand of -1.0.

Our low baseline projection was constructed by changing the price assumption made in the high projection to a one percent real electricity price increase a year through the year 2000.

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* Appendix II enumerates these and other assumptions.

** Real price refers to a constant purchasing power over the stated time period which essentially corrects for inflation.

***Elasticity of demand is the proportional change in quantity demanded in response to a proportional change in price.

Table 4-1 presents the results of both our projections and TVA's 1977 forecast for the residential sector.

TABLE 4-1

Residential Electricity Use Projections For the TVA Region

Year	TVA forecast	Our high projection	Our low projection
	--------	(billion kWh)	--------
1975	33.2	33.2	33.2
1980	40.1	39.6	39.0
1985	51.4	47.8	45.7
1992	70.2	59.0	53.1
2000	106.1	70.0	59.0

COMMERCIAL, INDUSTRIAL, AND FEDERAL DEMAND

A sophisticated model such as that used in the residential sector does not exist for the commercial/industrial sector. We, therefore, used a simple projection model (see app. II) for our two alternative projections for this sector.

Our Low Baseline Projection assumes:

--A one percent increase in the real price of electricity through the year 2000.

--A lower rate of economic growth; specifically, a gross regional product increase of an average rate of 5.8 percent a year through 1985, which slows to 4.0 percent a year during the 1986-92 period, and drops to about the national rate of 2.7 percent a year through 2000.

--A decline in energy interest of production (ratio of energy use to total output) after 1976 of one percent a year.

The High Baseline Projection used a constant real price of electricity and maintained a growth of 5.8 percent a year through the year 2000.

Uranium enrichment and other Federal consumption is projected at a constant rate of 40.5 billion kWh through the year 2000.* Table 4-2 shows the results of both our projections and TVA's forecast for the commercial/industrial sector and the Federal demand.

TABLE 4-2

Forecasts of Demand For Electricity in the Commercial and Industrial Sector of the TVA Region

Year	Federal Government	Industrial and commercial sector			Total demand industrial and commercial plus Federal Government		
	---(billions kWh)---						
		TVA (note a)	High growth	Low growth	TVA (note a)	High growth	Low growth
1975	20.1	50.1	50.1	50.1	72.1	72.1	72.1
1985	40.5	85.8	86.0	77.3	126.3	126.5	117.8
1992	40.5	125.2	120.5	93.4	165.7	161.0	133.9
2000	40.5	169.1	177.8	107.2	209.9	218.3	148.0

a/See "Industrial and Commercial Energy Consumption," Source book of TVA, Models and Projection Routines, 1977.

COMPOSITE DEMAND FORECAST

Table 4-3 presents TVA's forecast and our alternative demand projections for the total TVA system. Our high projection includes both residential and commercial high projections from tables 4-1 and 4-2 and our low projection includes both residential and commercial low projections. The implicit compound growth rates from 1975-2000 are presented in table 4-4 for each of the projections.

*In forecasting future energy requirements for uranium enrichment, TVA largely depends on DOE. Both TVA and GAO have used the amount of electricity DOE has contracted for through 1985 as a constant demand through 2000.

TABLE 4-3

Projections of Demand for the TVA Power Service Area

Year	TVA	Our high	Our low
	(billions kWh)		
1975	105.3	105.3	105.3
1985	177.7	174.3	163.5
1992	235.9	220.0	187.0
2000	316.0	288.3	207.0

TABLE 4-4

Implicit Compound Growth Rates For Composite Demand Projections 1975-2000

	Percent	
Projection	Without Federal purchases	With Federal purchases
TVA	4.8	4.5
Our high	4.3	4.0
Our low	2.7	2.7

IMPLICATIONS FOR PEAK DEMAND

In the 1977 TVA Load Forecast, peak demand was projected to grow at about the same rate as total demand. Our projection results when following this procedure are compared with TVA's forecast in table 4-5. In our low projection, peak demand in the year 2000 is 37,100 megawatts, which is about 40 percent lower than TVA's. Our high forecast is 51,900 megawatts, which is about 17 percent lower than TVA's.

TABLE 4-5

Projected Peak Demand for the TVA Region

Year	TVA	Our high	Our low
	---------------(Megawatts)---------------		
1975	18,600	18,600	18,600
1985	34,300	31,400	29,400
1992	46,700	39,600	33,600
2000	62,600	51,900	37,100

ENERGY SUPPLY

Our analysis presents a minimum cost strategy for meeting future generating capacity requirements in the TVA region after 1985. It concentrates on the trade-off between coal and nuclear systems and does not include the other programs (such as conservation and solar options) we propose that TVA undertake. It is designed to offer an appropriate context for evaluating those other programs.

Our definition of minimum cost includes economic costs plus other costs such as compliance with existing environmental laws and regulations. We assume that (1) units totaling 3,183 megawatts (MW) of conventional coal fired capacity will be fitted with flue gas desulfurization units, (2) varying numbers of fluidized bed combustion (FBC) units that will be capable of meeting sulfur emission standards, and (3) the seven nuclear powerplants totaling 20,245 MW completed or under construction will be operating by 1987 and any nuclear plants built after 1985 will meet the environmental and safety standards specified for the scheduled TVA nuclear plant at Yellow Creek, Mississippi.

In table 4-6, our earlier demand and peak load estimates are converted to estimates of required dependable capacity, assuming required dependable capacity to be about 22.0 percent greater than expected peak demand.* As shown, TVA's currently projected dependable capacity for the year 1992 and thereafter would be insufficient under its own demand projection. On the other hand, our projections indicate that there could be an excess capability ranging from 6,700 to 24,800 MW in the year 2000.

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*This ratio was suggested by TVA and is within the range generally considered reasonable by the utility industry.

TABLE 4-6

Required Dependable Capacity and Proposed Capacity Addition

Year	Required dependable capacity (note a)			Planned dependable capacity
	TVA	Our high	Our low	
	(megawatts)			
1975	22,700	22,700	22,700	25,100
1985	41,800	38,300	35,900	43,700
1992	57,000	48,300	41,000	55,000
2000	76,400	63,300	45,300	70,100

a/Estimated by us at 1.22 times peak demand.

TVA's expected average costs of generation indicate that through 1985 the nuclear power in the TVA region will cost less than coal-based power. The relative costs after that date are difficult to assess. Any conclusion depends on assumptions made on inflation, powerplant capacities, and other variables.

The extent to which nuclear power can be said to have a cost advantage and the time when application of the fluidized bed technology will make coal a least cost alternative, depend on the assumptions made. For our purposes, we have considered that an online fluidized bed capacity in operation in 1996 represents a least cost choice over the nuclear option. This assumption is based on available timetables for demonstration and commercial availability together with our analysis of projected costs.

We estimated future additions of capacity by supply type. Basically, we have minimized the total cost of the capacity additions in the selected years (1985, 1992, 2000) in terms of the costs of alternative power generation sources and the forecasted levels of demand.

The ratio of dependable capacity to peak demand in the TVA system in 1975 was a relatively high 1.29, but with projected capacity additions, TVA expects this ratio to fall to 1.24 in 1985. Our solutions maintain a desired ratio of dependable capacity to peak demand of approximately 1.22.

It is difficult to project the retirement of existing TVA coal-fired plants. TVA assumes that its Watts Bar coal-fired plant (224 MW) will be operating at a 32-percent capacity factor in 1992, at which time it will be 47 years old. Our baseline analysis assumes that the coal-fired capacity in the TVA region will not be retired prior to the year 2000 and that it will continue to operate at an average 41 percent capacity factor.

Table 4-7 shows our least cost supply strategies for each of the three projections. If our low demand projections are correct, the TVA system would need only to consider replacing existing conventional coal capacity as it is retired and maintain a sufficient dependable capacity to handle peak demand levels. It would essentially need no new expansions beyond its seven nuclear plants through the end of the century.

TABLE 4-7

Minimum Cost Supply Strategy

Year	Dependable capacity Hydro	Conv. coal (note a)	FBC (note b)	Gas turbine and pumped storage (note c)	Nuclear	Peak demand
	----------MW----------					
		TVA's demand forecast				
1975	3,882	16,901	0	2,424	1,762	18,633
1985	3,882	16,741	0	3,944	17,814	34,300
1992	3,882	16,741	0	3,944	32,468	46,700
2000	3,882	16,741	12,047	5,464	38,256	62,600
		High growth demand projection				
1975	3,882	16,901	0	2,424	1,762	18,633
1985	3,882	16,741	0	3,944	17,814	31,400
1992	3,882	16,741	0	3,944	23,723	39,600
2000	3,882	16,741	14,103	3,944	24,666	51,900
		Low growth demand projection				
1975	3,882	16,901	0	2,424	1,762	18,633
1985	3,882	16,741	0	3,944	17,314	29,400
1992	3,882	16,741	0	3,944	17,614	33,600
2000	3,882	16,741	2,800	3,944	18,123	37,100

a/Conventional coal does not include any retirement of existing capacity. Total coal generation in system assumed at 41 percent capacity factor. The reduction after 1975 reflects losses due to adding the scrubbers to 12 coal-fired units.

b/Beginning in 1996, fluidized bed technology is considered more attractive than nuclear.

c/The increases represent the pumped-storage plant at Raccoon Mountain (1,520 MW) and another under consideration for peaking in 1998. Gas turbines were assumed to operate at an annual capacity factor of 3.6 percent in our analysis, similar to TVA assumptions.

If the TVA demand projection or the our high demand projection are correct, TVA should consider the possibilities of full use of the fluidized bed technology in the 1990s. Our strategies use significant numbers of these combustion units towards the end of the century. If fluidized bed units provide greater flexibility and increased reliability, they could allow a reduction in total system capacity relative to peak levels of demand.

The impact of large increases in demand on the required size of the generating system are crucial. The addition of nuclear and fluidized bed capacity under the TVA demand forecast to the year 2000 of 30,058 MW, for example, represents an expansion of 148 percent of planned 1985 levels of nuclear power capacity. The more moderate demand increases given in our high demand projection would require considerably less expansion.

Nuclear systems may retain cost advantages over conventional coal-fired systems with FGD through the end of the century. The future competitiveness of coal depends, therefore, on the commercial viability of FBC systems by the utility industry in the 1990s. A national energy policy based on coal should, therefore, include a program to improve the competitive position of FBC through research, development, and demonstration in the late 1970s and early 1980s. TVA can play an important role in demonstrating FBC in the relatively near future.

Capacity requirements are related to the unresolved question of retirement of older coal-fired plants. Under conditions of low demand, the potential for introducing new technologies is limited to the replacement of facilities. Older plants might be economically retired sooner if an attractive alternative were available, a consideration which should encourage the rapid development of FBC systems.

INTEGRATION OF NEW TVA PROGRAMS FOR THE YEAR 2000

If the proposed coal strategy, industrial cogeneration, and solar programs discussed in the following chapters all succeed, they will lead to a substantial reduction in necessary total system capacity. The power management options in chapter 5 could alter projected peak load.

Implementation of the proposed coal strategy would add an additional 840 MW of net capacity to the TVA system. By the year 2000, the adaptation of industrial cogeneration could reduce required capacity by 3,350 MW and the adaptation of solar energy systems could further reduce it by 1,138 to 1,423 MW, achieving demonstration and/or application of our proposed programs.

Table 4-8 summarizes the possible impact of such programs. Under the TVA demand projection, this implies a 7.0 percent reduction in required dependable generating capacity in the year 2000. The reductions are even more impres ive under the our projections.

TABLE 4-8

Potential Effects of Our Proposed Programs on Projected Required Dependable Capacity in the TVA Region

Year	Projection	Baseline	Baseline and programs	Percentage Reduction
	----------------------	(Megawatts)	----------------------	
1985	TVA	41,800	39,779	4.8
1985	Our high	38,300	36,059	5.9
1985	Our low	35,900	33,659	6.2
1992	TVA	57,000	53,016	7.0
1992	Our high	48,300	44,071	8.8
1992	Our low	41,000	36,771	10.3
2000	TVA	76,400	71,072	7.0
2000	Our high	63,300	57,687	8.9
2000	Our low	45,300	39,687	12.4

Peak load reduction

Table 4-9 shows peak power demands for the year 2000 using a minimum cost projection and a projection adjusted for the coal, cogeneration, and solar options proposed in later chapters. Under the minimum cost strategy, existing hydro capacity, used primarily for peaking, and two pump-storage facilities could handle 9.0 billion kWh. Under our low projection, these two systems would be sufficient for projected peak demands. Under the TVA and our high projections, considerable additional peaking power would be required.

The power management demonstration could be expected to reduce peak power demands by 1.2 billion kWh by the year 2000. If TVA maintains a 3.7 percent capacity factor for its existing gas turbine capacity, an additional 2,513 MW of peaking capacity is required under our high projection to meet remaining peak needs. Under the TVA projection, however, at this capacity factor, a deficit over current capacity exists of 9,609 MW. The options open to resolve this problem if it should occur are (1) an expanded load management program, (2) more intensive use of existing gas turbines (i.e., increase the capacity factors), or (3) purchase additional gas turbines.

The right half of table 4-9 repeats the analysis with the potential capacity adjustments due to the proposed coal strategy, industrial cogeneration and solar systems included. The result is that the proposed load management program is nearly sufficient to meet peak demand with existing capacity under the our high projection. Under the TVA projection, however, a heavy gas turbine demand will remain.

TABLE 4-9

Effect of the Power Management Options and the Proposed Coal Strategy, Cogeneration, and Solar Program on Peak Loads in the Year 2000

	Minimum cost projection			Projection adjusted for coal, cogeneration, and solar programs		
	TVA	Our high	Our low	TVA	Our high	Our low
	(billions kWh)					
Projected peak demand	14.1	11.8	8.4	13.2	11.0	7.5
Less (1) hydro/pump storage (note a)	9.0	9.0	8.4	9.0	9.0	7.5
(2) Power management	1.2	1.2	-	1.2	1.2	-
Remaining peak demand	3.9	1.6	0	3.0	0.8	0
Additional required gas turbines (MW) (note b)	9,609	2,513	0	6,840	44	0

a/Assumes completion of two pump storage facilities.

b/Existing gas turbine capacity is 2,424 MW and assumes a 3.7 capacity factor.

CHAPTER 5

MODIFYING ENERGY DEMAND THROUGH

CONSERVATION AND MANAGEMENT

TVA has added new generating capacity to meet projected increases in demand. It has not fully pursued options which could (1) reduce the growth rate of energy demand, (2) make the existing power system more efficient, and (3) defer the expansion of generating systems until a later date.

Conservation has been viewed as a key component of any solution to the Nation's energy problems. It would require changes in traditional consumer patterns, and greater use of energy efficient materials.

Federal efforts are reflected in recent legislation. The Energy Policy and Conservation Act was passed in December 1975, and the Energy Conservation and Production Act in August 1976. Title IV of the Energy Conservation and Production Act authorized four programs:

--Weatherization assistance to low income, low income handicapped, and elderly persons ($200 million authorized funding).

--Financial assistance to States developing and implementing energy conservation plans ($105 million authorized funding).

--Financial assistance to owners of existing dwellings ($200 million authorized funding).

--Loan guarantees to those implementing energy conservation and/or renewable resource measures in any building or industrial plant ($60 million authorized funding).

The Department of Energy has set conservation goals for industry and is encouraging test innovative rate structures by utilities.

Until March 1977, TVA's energy conservation efforts were mainly educational and demonstrative. Little was done to discourage consumption or conserve energy through more efficient production techniques.

TVA's performance was similar to those of most private utilities. Our evaluation of 28 utilities showed that most began presenting conservation programs in 1970 only as a result of rising energy prices or supply shortages.

Each utility contacted had some type of energy conservation program for residential consumers. Educational materials were sent with utility bills, public inquiries were answered, and, in some cases, long-term financing was provided to insulate customer homes. The results cannot be measured. Home insulation programs are not yet widely accepted. In one city of about 4 million homes, an insulation program involved 2000--or less than 1 percent. DOE-sponsored surveys indicate that residential insulation is increasing but the efficiency of such insulation is not adequately known.

For the TVA region, we considered three conservation alternatives: residential programs, industrial cogeneration, and power management.

RESIDENTIAL CONSERVATION

In this section, we tested the impacts of the three residential programs* proposed in the National Energy Plan (NEP) 1/, the impact of the use of heat pumps, and the impact of increasing the real price of electricity.

NEP proposed residential programs

We believe the NEP goal of insulating 90 percent of all residences by 1985 will be difficult to achieve 2/, particularly in the TVA area where electricity prices are low and winters usually mild. We, therefore, estimated that 56 percent of the single-family units occupied in the TVA region in 1975 and 25 percent of the multiple family units will be retrofit by 1985.

Our baseline projection (High) of residential electricity usage, which assumes that the three NEP programs will be implemented, results in a reduction of use of 3 million kWh by 1990 (to a level of 53.3 billion kWh). This results in a growth rate of 3.4 percent a year as compared with TVA's projection of 4.7 percent a year through 1990.

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*Developing appliance efficiency standards, creating thermal standards for constructing new residences by 1980, and implementing several measures to encourage the insulation of 90 percent of the existing residences by 1985.

These three programs would also reduce energy-related household costs. Discounting all benefits and costs from 1977-2000 to 1977 prices, at a real interest rate of 8 percent, yields a net benefit to the region's households of $90 million. (Fuel bill reductions of $690 million are offset by increased capital costs for improved equipment and structures of $600 million.)

TVA currently has two programs underway that endorse these programs. Its "Super Saver Home" project, in which TVA works with distributors and builders to design and construct energy-efficient residences, helps implement the thermal standards being developed by the Department of Housing and Urban Development.

The second TVA program encourages attic insulation or weatherization for low-income families. TVA first selected 219 families to receive free home insulation or weatherization. Each had to (1) have an annual income of no more than $6,000, (2) own and occupy the home, (3) heat it electrically and have a record of unusually high bills, and (4) sign an agreement to participate in the demonstration program for at at 3 years. TVA contracted to completely weatherize 81 homes and TVA installed attic insultion in 138 homes.

The homeowners agreed to provide information for 3 years on changes in electricity consumption, family living habits, and home comfort. Unfortunately, the 219 homes were not randomly selected nor representative of Valley residences, and it will be difficult for TVA to make valid projections on the basis of this sample.

The plan was expanded in March 1977 to provide interest free loans to owners of electrically heated or cooled residences who agree to insulate them. By 1982, TVA plans to make such loans to about 750,000 customers who heat or cool electrically. Private contractors will install standard R-19 level insulation in these homes (six inches of rockwool or equivalent). TVA expects the cost to average $350 a customer and to be recovered in 3 years through electricity use savings.

Use of heat pumps

The use of heat pumps can cut the energy used in central residence-type heating systems by as much as 50 percent in the TVA region. In winter, a heat pump draws heat from the outside air and circulates it inside the house. Until the outside temperature drops below about 30 degrees Fahrenheit, the only electricity required is the amount needed to run the heat pump's compressor and fan. When the outside temperature is 30 degrees or below, the heat pump requires the help of auxiliary resistance-type heating elements. In the summer, a heat pump reverses the process, exhausting heat from the house, like a central air conditioning system.

TVA has projects which include the education of installation and service people and the certification of dealers who demonstrate proper heat pump installation and maintenance.

Heat pumps require a greater volume of air circulation than conventional heating systems and are not easily installed in existing residences. To measure the effects of a program that encourages TVA customers to choose heat pumps, we assumed that all electric heating systems to be installed in new construction in the region through the year 2000 would include heat pumps with an average 40-percent savings over resistance-type heating systems.

The results showed that energy growth would be cut slightly, from 3.8 to 3.6 percent a year in our high demand projection. Residential electricity use in 1990 would decrease by 1.3 billion kWh, to 55.0 billion kWh. Projected fuel bill reductions due to heat pump usage ($220 million) are greater than the increased capital cost ($170 million) by $50 million.

<u>Impacts of increasing real price of electricity</u>

To a large extent, estimates of future residential electricity demands in the TVA region depend on assumptions made on the future cost of electricity. TVA estimates that the real price of electricity will remain constant over the time period 1975-90. This constancy assumes the use of large nuclear power plants with low operating costs.

Because TVA's estimate of future electricity prices is different from the conventional beliefs in rising prices, our low baseline projection shows an increasing price of electricity at an average annual rate of 1.0 percent a year.* The purpose was to evaluate the sensitivity of residential electricity use to the price of electricity.

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*The DOE projection of future residential electricity prices shows an average growth rate of 1.0 percent to 1990.

With rising electricity prices, residential electricity use would grow at an average rate of 3.1 percent a year, this compared with 3.8 percent under our high projection. Consumption would be 51.6 billion kWh in 1990, 8 percent less than in our high projection and 13 percent less than TVA's projection. This analysis indicates that electricity price changes have important consequences on demand. Table 5-1 and figure 5-2 summarize these effects.

In our low projection, regional household expenditures would increase by $670 million (about $240 a household). This increase would be less than might be anticipated because of certain factors. High fuel prices (compared to the original baseline) would cause consumers to reduce consumption. This would result from systems changes, use of more efficient equipment (with some switching from electricity to other fuels) and changes in behavior (e.g., shorter showers and closer attention to thermostat settings).

Combined impacts on our high and low projections

We next examined the case in which both the heat pump and the three residential programs are implemented. This combined situation reduces electricity growth under our high projection from 3.8 to 3.1 percent a year. Residential electricity would be reduced from 56.3 billion kWh to 51.6 billion kWh in 1990. The combined program would produce a net total savings to the region's households of about $190 million. The savings due to the combined programs would be greater than the sum of separate savings because the NEP appliance efficiency standard would affect gas heating systems. The standard is set at so strict a level that region households would probably shift from gas to electricity when selecting new heating systems and with the heat pump program, they would probably shift to energy-efficient heat pumps rather than resistance heating.

The combination of the three residential and heat pump programs on our low projection would limit growth in residential use to 2.6 percent per year. Residential use in 1990 would total 48 billion kWh--15 percent less than the high projection figure. The net economic savings through 1990 from these programs, $190 million, would equal the saving implied under our high projection. The following table 5-1 and figures 5-1 and 5-2 illustrate the impacts on residential electricity use of these conservation programs on both our high and low projections.

TABLE 5-1

Residential Electricity Use Projections
For the TVA Region

Year	TVA forecast	Our High Projection: Base	Our High Projection: NEP effect	Our High Projection: Heat Pump effect	Our High Projection: Heat pump and NEP effect	Our low projection: Base	Our low projection: Heat pump and NEP effect
	(billion KWh)						
1980	40.1	39.6	38.4	39.0	37.8	39.0	37.2
1985	51.4	47.8	45.1	46.9	44.0	45.7	42.5
1990	63.9	56.3	53.3	55.0	51.6	51.6	48.1
1995		63.0	60.1	61.5	57.7	55.4	51.9
2000		70.0	66.5	68.3	63.6	59.0	55.4

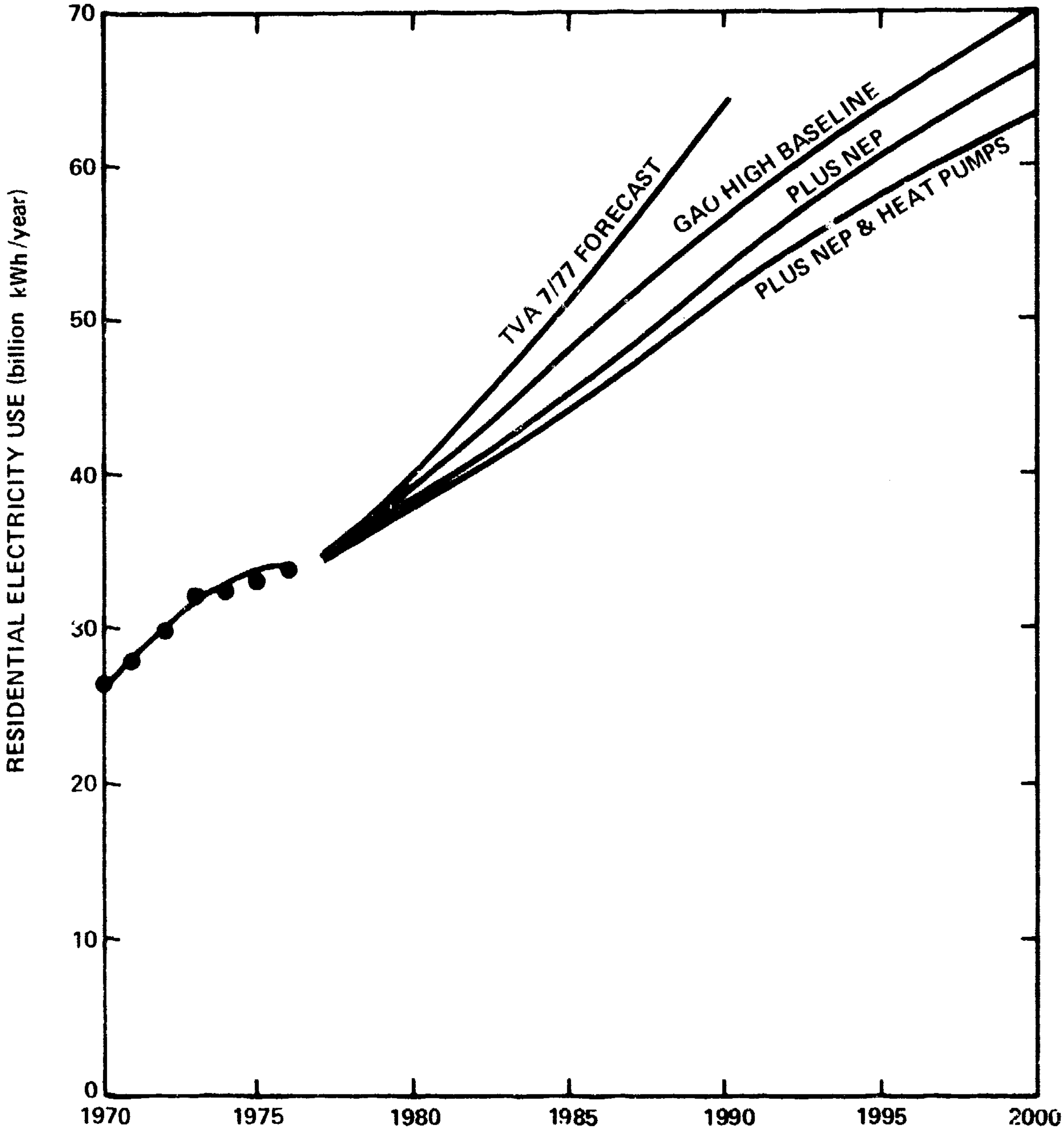

FIGURE 5-1 PROJECTIONS OF RESIDENTIAL ELECTRICITY USE WITH AND WITHOUT GOVERNMENT CONSERVATION PROGRAMS, ASSUMING CONSTANT REAL ELECTRICITY PRICES.

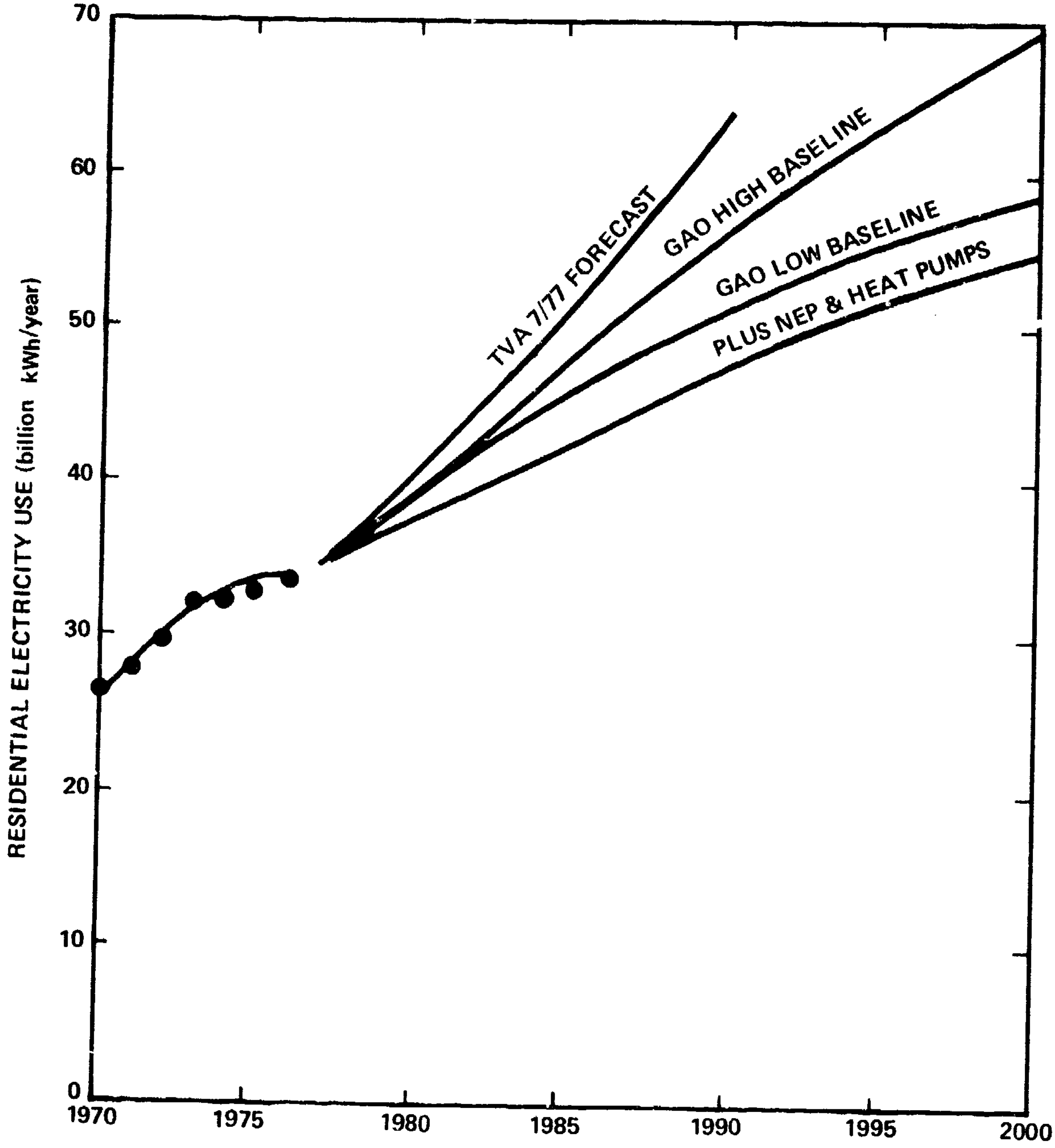

FIGURE 5-2 PROJECTIONS OF RESIDENTIAL ELECTRICITY USE WITH AND WITHOUT GOVERNMENT CONSERVATION PROGRAMS ASSUMING RISING REAL ELECTRICITY PRICES.

INDUSTRIAL COGENERATION

Industrial cogeneration is the generation of electricity and heat as a by-product of the industrial production of process steam. 3, 4/ Cogeneration was once widespread. In 1920, about 30 percent of all U.S. electricity generated at industrial sites was produced through cogeneration. This figure has now fallen to about four percent. 5, 6/

Advantages of Cogeneration

Several feasible cogeneration systems seem economically attractive. 7, 8/ Cogeneration can cut fuel use as much as 50 percent below the level of central power stations. Compared with a nuclear plant coming on line in the 1980s, an oil-fired cogeneration system using gas turbine technology, is estimated to have an average of 12-16 mill/kWh cost advantage nationally. 8/ Cogeneration has several other advantages over central powerplant generation

- --less air pollution generated per unit of usable transformed energy,
- --greater flexibility in siting,
- --greater flexibility in meeting uncertain demand futures,
- --equal or lower cooling water requirements, and
- --reduced total capital requirements.

Potential for cogeneration

The principal reason for the decline of cogeneration systems in the United States has been the relatively low average price of electricity produced at central power stations. This price fell continually until the 1970s. Since the early 1970s, however, the trend in electricity prices has turned upward. The proposed national policy discourages the use of natural gas and highly refined distillates as boiler fuel, and encourages the use of coal, creating opportunities for replacing and modifying boilers. These factors could lead to a wide-spread replacement of single-use steam systems with cogeneration systems.

A cogeneration arrangement between industry and an electric utility for a $15 million coal production of electricity and processed steam was recently announced. 11/ The coal-fired system will be constructed by several industries including Union Carbide, Monsanto, and subsidiaries of Standard Oil Company (Indiana) and the steam produced (3 million lbs/hr) will be used in nearby industrial plants. The electrical power (about 150 MW) will be distributed by the Community Public Service Company of Texas City, Texas.

Table 5-2 presents two estimates of cogeneration potential in the United States The technical potential estimates are the maximum potential for cogeneration power and could equal 200,000 MW by 2000. This would eliminate the need for any new central station generating capacity beyond plants currently under construction or scheduled for replacement, if national demand grew at 3.5 percent a year. 6/ The projection column represents the amount that might actually be on-line in the future. 3,6/

TABLE 5-2

Estimated Potential for Industrial Cogeneration in the United States

Year	Technical Potential (note a) (quads) (note c)	Projection (note b) (quads) (note c)
1975	--	0.8
1985	1-4	1.3
2000	3-10	2.0

a/See footnotes 3, 9. Lower values reflect the potential offset of steam turbine technology only. The higher figures correspond to the combined potential of steam, diesel, and gas turbine cycles.

b/See footnotes 3, 9. The projected values are considerably lower than the technological potential because of combined constraints from institutional conservatism, regulatory barriers, and the lack of sufficiently strong economic incentives. New public policies, such as those proposed in the NEP, could, of course, cause these projections to increase considerably.

c/One QUAD (10 Btu) corresponds to the annual output of about 20,000 megawatts of installed baseload capacity.

The above estimates provide only a perspective and further information is being developed. (A separate GAO study, EMD-78-38, concerning the Nation's conservation efforts was issued June 30, 1978. Another report on the role of cogeneration in the Nation's conservation efforts should be completed in late 1978.)

Barriers to development

In the development of cogeneration systems, the attitude of utility companies is critical. An industrial cogenerator might either have excessive capacity or it might require a back-up source of supply. In both cases, the cooperation of a utility and agreement on reasonable power exchange rates would be required. Neither are likely to be in the utility's best interests if electric utilities continue to have a large excess capacity in the near future. Several other factors contribute to a lack of industry interest:

--Reluctance to generate electricity because of the capital intensity and relatively low rate of return.

--Desire to avoid regulation by State and Federal agencies.

--Current electricity pricing policies which now provide industry the benefits of average cost pricing and in some cases, declining block rates.

--Uncertainty regarding optimum equipment and fuel systems.

--Uncertainty with regard to trained manpower for operations.

--The need for added space for cogeneration facilities and the regulatory requirements that must be satisfied in constructing such new facilities.

Cogeneration systems with boiler sizes greater than 200 MMBTU/hour are the most economical (this limit might decrease with improved technology). With declining block rate schedules, the largest consumer pays the lowest average price for power. Thus, industry-owned and operated cogeneration facilities would compete with utilities on very unfavorable terms.

Factors which contribute to a lack of utility interest include

--a reluctance to employ capital to serve a limited number of steam customers and

--unwillingness to purchase electrical power from sources which they do not own or control.

Most of the obstacles to adopting cogeneration systems result from an assumption of industry ownership. If cogeneration units are owned by utilities the prospects are much more favorable:

--Cogeneration may be economically advantageous to utilities facing construction delays for new capacity.

--Utilities would be able to build plants of an optimum size.

--The regulated utility industry might undertake a cogeneration investment with a lower rate of return.

--Electricity transmission and distribution costs are a major cost factor in cogeneration industry connections with utility grids used solely for contingent and/or periodic power. These are costly because of the low capacity factors. If power is exported to the utility the capacity factor can increase sharply, significantly reducing "standby" costs.

Utility ownership would not, however, resolve uncertainties in fuel choices and technology. More advanced systems such as coal-fired gas turbines (e.g., a pressurized fluidized bed combustor with a directly fired gas turbine and waste heat boiler), are not likely to be available until the mid-eighties. Advanced technology could permit the use of alternate fuels such fuels such as residual fuel oil or biomass.

--A coal-fired steam system requires a greater investment than a gas turbine system.

--The use of coal-fired steam turbines would seem to be in line with the national energy policy encouraging the increased use of coal. Although the high efficiency of the combustion turbine might permit the use of oil or even gas, additional research would be necessary to consider alternative uses of gas. Combustion turbines are also efficient at smaller sizes than are steam turbines (at or below 100 MMBTU/hour).

A cogeneration role for TVA

A major program of industrial cogeneration by TVA would serve national goals in four ways:

- --It would provide hard data to establish expected high fuel efficiency of cogeneration systems.
- --It would demonstrate the advantages and disadvantages of utility-owned industrial cogeneration systems at industrial plants.
- --It would demonstrate the savings in both energy and dollars and social benefits that might result if utilities develop cogeneration.
- --It would reduce the uncertainty regarding cogeneration technology and fuel.

The potential capacity for cogeneration in the TVA region is estimated in table 5-3. Cogeneration is generally considered to be most cost effective at boiler sizes greater than 200 MMBTU an hour. 8/ We have identified 60 boilers this large or larger in the TVA region. Those boilers, with 3.8 boilers per location, averaging 320 MMBTU an hour, should improve the potential benefits of efficient cogeneration. Total steam demand at each site is important because boiler consolidation will likely occur over the next 15 years to take advantage of economies of scale.

TABLE 5-3

Estimated Potential Capacity Through 2000 for Industrial Cogeneration in the TVA Region

Year	Cogeneration (note a) Potential	Equivalent central (note b) Station capacity
	(billions of kWh/yr)	(MW)
1977	7 -14	1,200 - 2,300
1985	13 - 20	2,100 - 3,300
1990	23 - 26	3,700 - 4,300
2000	32 - 41	5,200 - 6,700

a/The following rates of electricity generation per million BTU of steam are used: steam turbine = 50 kWh, gas turbine = 200 kWh, combined gas/steam turbine = 300 kWh, diesel = 400 kWh. 8, 10/ These figures presented in this column represent weighted averages of these technologies. It is assumed that in earlier years greater use will be made of the steam turbine while in later years greater use will be made of the gas and combined turbine systems. For example, the low 1977 estimate assumes all steam turbines while the low 2000 estimate assumes an average kWh/yr per million BTU of steam of 140.

b/This range assumes operation at a 65- to 70-percent capacity factor.

Based on the existing capacity of 200 MMBTU an hour and larger boilers in the TVA region in 1977, the potential capacity for cogeneration is estimated at 7-14 billion kWh/yr. Table 5-3 shows projections of this potential to 2000. In the last column, the potential capacity for cogenerated power in the region is converted into an equivalent central station capacity. Assuming 70-percent capacity factor, the 1977 cogeneration potential in the region could replace at least one large nuclear unit, while by the year 2000 the substitution potential could total 5,200 to 6,700 MW or the equivalent of five large nuclear units.

As in the case of the national data presented in table 5-2, the significant potential for cogeneration does not mean these systems will be installed. TVA is currently conducting a survey to obtain more detailed information. One piece of critical information is the number of boilers fired by oil and natural gas which may shift to coal in the near future. Another is the degree to which cogeneration technology could be applied to current boiler capacities in the 100-200 MMBTU/hour range. The potential for cogeneration might best be realized if TVA worked with new industries as they locate in the region and with existing industries as they expand. New industrial parks could provide the opportunity for optimal cogeneration.

TVA could undertake a major application/demonstration of cogeneration technologies such as:

--A coal-fired steam turbine system in the several tens of megawatt range.

--A gas turbine system in the 50-200 MW(e) range capable of using alternative fuels (i.e., No. 6 oil, methanol, residual fuel oil, etc.) in a cogeneration mode.

--A gas turbine system suitable for installation at smaller industrial locations. This system should be designed so that important questions related to economies of scale can be answered and should also be capable of operating with different fuels. (Demonstration of these developed technologies could be made at one of the large chemical complexes at Decatur, Alabama.

--A fluidized bed gas turbine system coal-fired system could be coordinated with the work of American Electric Power Company (AEP). The AEP system is not designed for simultaneous use of steam by industry. Rather, steam from the gas turbine is run through a steam turbine to produce additional electricity. The TVA demonstration should be in the size range to demonstrate the capacity of feeding excess generation to the network and simultaneously producing process steam for industry.

--A fluidized bed gas turbine system fired by biomass, in particular wood waste. This demonstration could be located in major wood and paper products industrial complexes such as the one in Calhoun, Tennessee.

The principal objective, as opposed to the coal-fired system, would be to develop alternative fuel cycles, particularly concentrating on the use of industrial and agricultural wastes, and perhaps municipal waste.

These TVA projects would make cogeneration more feasible. Each system should be monitored to determine economies of scale, fuel type, operating and capital costs, increases in transmission and distribution costs, and the ability of the systems to fit into the overall TVA power system.

Since the benefits of successful adoption of cogeneration systems are nationwide, any added costs over and above TVA'a traditional power costs could be federally funded. These costs could simply be based on an analysis of TVA's incremental costs for new powerplant construction. Such risk sharing could permit TVA to justify extended efforts using advanced technology.

POWER MANAGEMENT

Demand for electrical energy is variable and utilities have traditionally supplied power through a combination of strategies. These include:

Load-following generation. Base load plants, typically nuclear, coal, or oil-fired, provide a steady source of power. Intermediate load plants, typically coal, oil, gas-fired, or hydroelectric, are turned up and down to match demand. Peaking generation is used to meet short-term, low duty-cycle peaks and include gas or oil-fired turbines, pumped storage, and hydroelectric facilities. The pumped storage method uses base load plant output during periods of low demand to pump water to a higher reservoir, enabling it to be used later for peak demand. Generally speaking, the most expensive power on a per unit of energy is peaking power and the cheapest power is base-load power.

Power pooling. When other utilities have different seasonal demand peaks it is possible for utilities to exchange power to better use spare capacity on the one hand and to avoid the need for additional capacity on the other.

Scheduled maintenance. During seasons of low demand (spring and fall) major maintenance and repair operations take place, enabling the utilities to maintain higher operating loads during the rest of the year.

Load Management. In contrast to the other strategies, there are mechanisms to shape (flatten) the time-dependence of load so that costs to both producer and consumer are minimized. Such strategies have received relatively little attention by U.S. facilities until very recently.

The first three mechanisms have been the key to TVA plans for meeting electricity demand. In this section we review TVA's power supply methods and discuss additional efforts to improve performance through load management.

Current TVA power management

Because power purchases in the TVA region are heavily dominated by industrial customers that consume power at a constant rate, the time variation of TVA's load is relatively small compared to other utilities. Figure 5-3 shows the typical time dependence of TVA's load for a winter and summer day. Figure 5-4 illustrates the annual variation in load. On Figure 5-5, about 79 percent of TVA's demand is shown to be base load, about 17 percent is intermediate load, and about 4 percent is peak load. As a consequence of this unusually favorable load pattern, TVA's average annual load factor totals 67.7 percent with an average plant capacity factor of 52.3 percent. These figures compare favorably with national averages of 62 percent and 49 percent, respectively.

The most significant power management activities currently used by TVA are:

Load following plants. TVA's present mixture of base, intermediate, and peaking capacity will be augmented over the next several years with several nuclear plants and a large pumped hydro storage facility. The new nuclear plants, which were initiated several years ago, should provide additional power at relatively low cost and enable TVA to slow the rise in electrical rates. The pumped hydro facility under construction at Raccoon Mountain will enable TVA to cut back the use of (distillate fuel) peaking turbines. There are several limitations to pumped storage--site availability, a 30-percent energy loss during processing, and capital costs--that must be compared with alternative opportunities to shift electrical demand loads for the same results.

Power pooling. TVA, a winter peaking system, has interchanged agreements with several utility groups whose peaks occur in the summer months. TVA has an arrangement with Mississippi Power and Light Company for the exchange of 1,500 MW of power when needed. In addition, exchange arrangements have been made with the Southern Company for 300 MW and the Central Illinois Public Service Company,

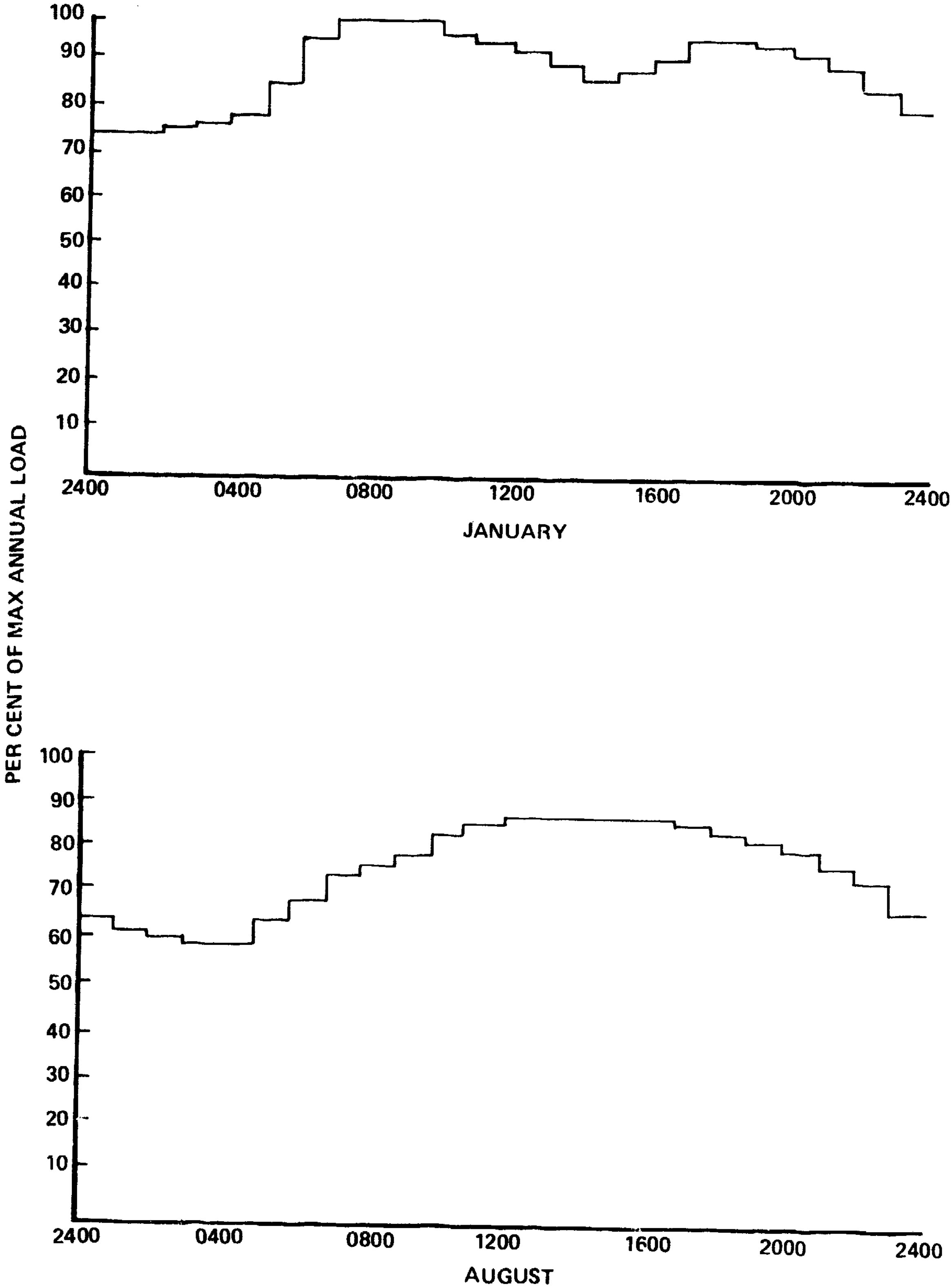

FIGURE 5-3 TYPICAL DAILY LOAD PROFILE

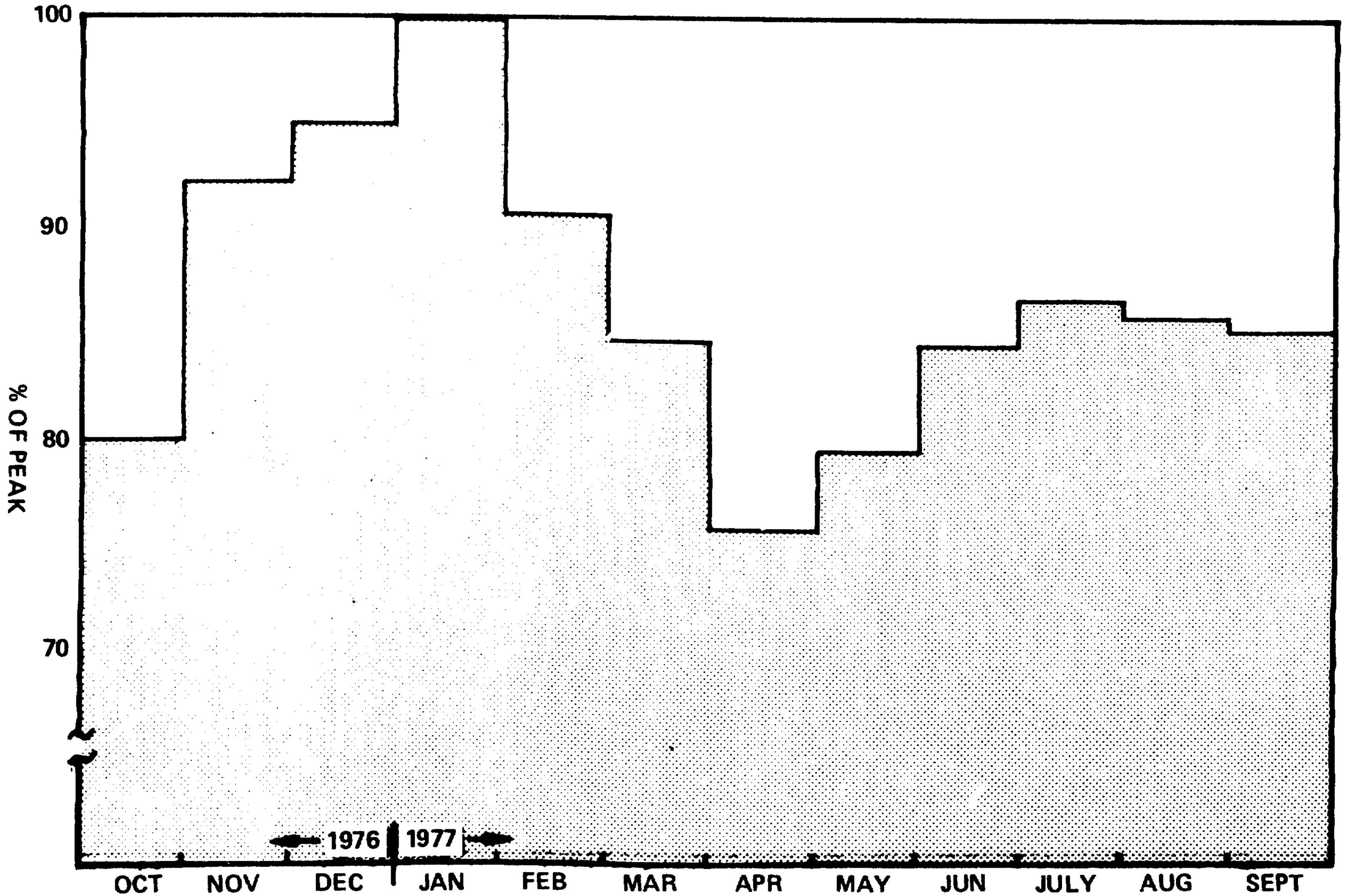

FIGURE 5-4 ANNUAL NET SYSTEM LOAD

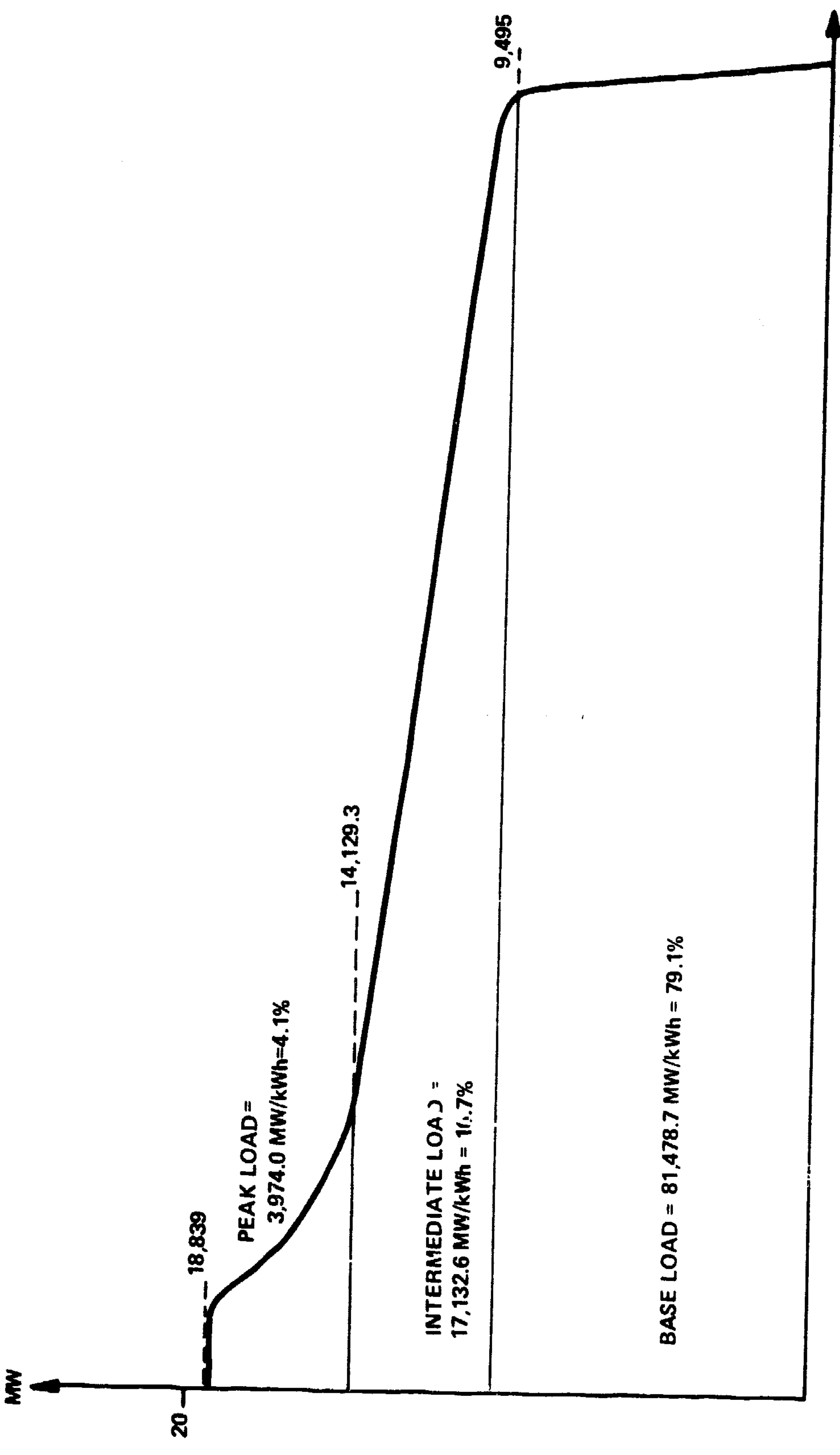

FIGURE 5-5 1975 LOAD DURATION CURVE
NET GENERATION = 102,585.3 kWh

Illinois Power Company, and Union Electric Company for 250 MW. This total interchange power of 2,050 MW is considered by TVA to be firm generating capacity during its peak season and is so counted in all generation planning studies.

However, exchange reductions are anticipated in the near future. At the beginning of the winter exchange period in 1979, the interchange agreement with Mississippi Power and Light Company will be reduced to a 1,100 MW level while the agreement with the Southern Company will be reduced to 220 MW. These changes will reduce the amount of exchange power on the TVA system from 2,050 MW to 1,580 MW. In addition, after the beginning of the winter exchange period of 1980, the interchange level with Mississippi Power and Light will be further reduced to 700 MW and the agreement with the Southern Company will drop to 140 MW, lowering the amount of interchange power from 1,580 MW to 1,100 MW. Interchange agreements are being reduced because TVA's summer peak is increasing; thus the differential between winter and summer peaks is diminishing.

Load management. TVA has only one significant activity in this area, consisting of certain power contracts which allow interruption of service. The majority of TVA's contracts for interruptible power allow for up to 3-percent disruption during a 10-year contract period. The agreement allows breaks to be made at undetermined times with advance notice of as little as 5 minutes. The discount offered from the current firm rate is about 8 percent. TVA currently has about 800 MW of interruptible power under contract.

Unfortunately, the timing and magnitude of peakshaving through such interruptible agreements is limited. The contracts are clearly designed for providing TVA with an improved capacity to respond to emergency situations. In other words, the contracts should enable TVA to operate with a lower reserve margin than otherwise requested.

The prospects for expanding such minimum discount contracts in the future are limited because of (1) the cost and technical difficulty with which many industrial and commercial customers respond to interruptions (2) the relative low value of electricity costs as factors in production, and therefore the relatively low priority given to a contract that offers only small savings and (3) complementary labor problems. The substantially higher cost of peak power may enable TVA to offer more than an 8-percent discount and consequently expand the amount of interruptable power--on a regular or emergency basis.

Time-of-day pricing. In one small study, 100 existing water heaters from each of four different distributors will be controlled along with space conditioning (air-conditioning and heating systems) using radio control. In addition, 25 120-gallon water heaters purchased by TVA will be installed, controlled, and monitored in randomly selected homes. The purpose of the study is to determine the amount of peak reduction which may be attained on the system and if the water heaters can be charged enough during offpeak hours to supply hot water during other hours. This information will allow TVA to determine whether or not the customer could benefit from a time-of-day rate in conjunction with the water heater (or perhaps the purchase of a larger water heater) as well as the benefit on the whole system.

A small TVA program analyzes the time-dependence of residential loads. This program applies time-of-day rates to 100 residences with a control group of an additional 100 homes. This short-lived program will do little more than explore the consumer's willingness to change personal energy habits in order to save money. It may even produce erroneous data and hamper TVA's proper evaluation of time-of-day pricing. The program does not touch the basic issue of technological responses. TVA declined DOE's offers of both technical and financial assistance as early as January of 1977. 12/

The 1 year examination ignores the most significant benefit of peak pricing--the developing of product designs to reduce peak demand. For example, water heaters account for about 24 percent of power use among TVA's residential customers. Peak pricing could stimulate investment in larger, better insulated heaters which could be turned on and off during peak hours. FEA witnesses before the Public Service Commission of New York estimated that a system with 2 million water heaters could, through an interruption during peak hours, reduce its peak load by 2,000 megawatts--more than the capacity of the Kingston steam plant. 13/

Other utilities are conducting tests which surpass TVA's past efforts. Georgia Power Company has an $850,000 peak pricing study involving 3,000 homes. It includes a visible and audible signal to tell the consumer when peak pricing time is coming. It may also include an optional device which would automatically remove heavy electric loads from the customer's system during peak demand periods. Georgia Power began a 300-home demonstration program more than 3 years ago in which thermostats automatically shut down air conditioners for 15 minute intervals during the summer peaking times. It found that by sequentially switching units on and off, it shaved demand by 1.4 kilowatts for each air conditioner. 14/

A similar project by Arkansas Power and Light indicated savings of as much as 4.17 kWh per central air conditioned residence. Such a reduction can produce significant savings because control equipment is less expensive than generation equipment and fuel. During winter's coldest day in 1975, Buckeye Power of Ohio cut back water heaters in 10,000 homes for 3-1/4 hours, with a shaving of about 14 MW during the peak hour, a cost of only about $65 per kilowatt saved. Buckeye Power now has about 35 MW of curtailable water heater load on about 32,000 customers. Residential customers of the Green Mountain Power Company (Vermont) expressed universal satisfaction with the off-peak rate, and have been able to reduce their bills by an average of 15 percent. 15/

Demand management strategy for TVA

Effective load management can produce savings for both the utility and the consumer. 16, 17/ One strategy is to influence the demand to minimize the use of peak generators which are large and inefficient consumers of gas and petroleum distillates.

With successful load management, savings can more than offset its cost. 18, 19/ For example, TVA's newest nuclear generating plant (Yellow Creek) will have an investment cost of at least $837 a kilowatt. The cost of programs which reduce peak demand is less than the cost of new construction.

Load management also saves gas and petroleum distillates. The net shift of demand from peak times to base-load time would permit the use of nuclear and coal fuels in place of distillates. The move could also decrease the need for pumped storage, saving saving the attendant energy losses (30-35 percent) and the investment costs in capital and land.

It is appropriate that the rates reflect the increased cost of producing power during peak hours (and seasons). 20/ The existence of time-dependent rates can result in consumer adjustments decreasing peak loads. Special rates can be established for customers who are willing to be interrupted for varying periods of time on either regular or irregular bases.

Seasonal and time-of-day rates for a broad range of customers can induce a significant reponse if the rates reflect the cost difference between base and peak power--about a factor of three. Such a response would be enhanced if TVA, and its power distributors, provided technical and financial assistance to customers purchasing rate responsive equipment (e.g., timed water heater switches, automatic "lock-out" switches for major appliances, stored heat, and cool systems). TVA could encourage the cooperation of power distributors by fixing higher charges for peak hours of demand in their wholesale power contracts. It would then be economical for the distributors to install time-of-day rate meters and other equipment to level the load.

Since TVA experiences a higher peak demand in the winter, it would seem logical to use higher rates during that season as well as daily peak day/night differentials around the year.

Presently, TVA's reliability criteria (loss of power on 1 day in 10 years) is used to develop contracts with its interruptable customers. TVA's present interruptable contracts are designed to meet only unanticipated, irregular, and abnormal conditions. While such agreements are helpful in contingency planning, TVA could also offer lower rates for special time-of-day curtailment--during daily peak load hours in summer and winter. Ripple control systems which invite the use of the most attractive rates, should be applied to a wide range of customers.

Interruptible contracts can also provide for regularly switching off certain equipment (such as water heaters) during peak load hours. The inherent storage capacity of water heaters permits this action with little attendant customer inconveniences. Interruptible contracts can provide temporary utility-controlled cut-offs of certain equipment, such as air conditioners, compressors, and irrigation pumps. Arkansas Power and Light Company has demonstrated the considerable savings available from remote, temporary shutdowns of the air conditioning and irrigation pump loads. 14/ It was found that air conditioner compressors could be switched off for 25 percent of the time during system peak demand without noticeable discomfort by consumers, except those located in very poorly insulated buildings.

Table 5-4 illustrates the potential benefits of interruptible actions. Using a combination of remote control and timer equipment, we calculated the effect of installing load interruption capability in at least 50 percent of all electric water heaters in the region by 1985. The resulting decrease in peak load would equal about 1,000 MW of residential savings plus about 500 MW in the commercial and small industrial sector.

TABLE 5-4

Benefits of Load Management: Interruptible Options for the TVA System (1985)

	Scenario		
	TVA	Our low	Our high
Winter peak required capacity			
Without load management (MW)	34,300	29,900	28,200
With load management (Time controls on water heaters)(MW)	32,470	28,070	26,370
Savings (MW)	1,830	1,830	1,830
Savings in capital investment eschewed (millions dollars)	$300	$300	$300
Summer peak required capacity			
Without load management (MW)	34,300	29,900	28,200
With load management (time controls on water heaters and air conditioners)(MW)	31,860	27,460	25,760
Savings	a/	a/	a/

a/No savings would result from reduced summer demand; the chief advantage would be the ability to schedule annual maintenance for capacity totaling 2,440 MW during this time.

We also projected the impact of installing remote controls on at least 50 percent of all air conditioner compressors of size equal or greater than 15,000 BTU per hour by 1985. The resultant decrease in peak load from the residential sector alone would be about 300 MW if we assume that a maximum of 25 percent of controllable units can be turned off at any given time during a peak load period. Peak demand savings in the commercial sector could further amount to an additional 200 MW.

The peak demand in summer 1985, could be reduced by some 2000 MW by these two actions alone; the winter peak could be lowered by 1,500 MW. Since the winter peak is highest in the TVA system, it remains the most critical figure. Because instantaneous demand requires an equivalent amount of capacity plus a safety margin of 22 percent, 1,830 MW of capacity could be eliminated in 1985. The cost of this much capacity, even at $200 per kWh would total $300 million, compared with $94 million for the alternative load control (assuming $100 per

per unit of installation). 18/ Although the reduced summer peak would not affect the total need for generating capacity, lowering the peak by 2,440 MW during summer months would allow more flexibility for normal maintenance of powerplants. Winter peak demand management thus offers better system-wide control as well as significant savings in capital investments.

There is inadequate energy demand data for the TVA system to project future industrial needs satisfactorily and we cannot, therefore, estimate the potential savings which could be achieved by matching time-varying residential and commercial loads with variable industrial loads. The potential for reducing peak demand by interrupting industrial customer's supply (whose processes would not be detrimentally affected) is probably great, but we lack information to make even preliminary estimates. TVA could determine this potential and offer industrial customers incentives such as reduced off-peak rates.

Variable loads can be matched to effectively level demand. Some industrial processes can be operated over a relatively wide variation of electrical power input and under certain conditions, a varied load could be joined with a more conventional load to make a total demand constant. Texas Power and Light Company and the Aluminum Company of America recently agreed to such a plan 21/ in which each shares the capital costs of a plant and shares the electrical output. During the utility's peak needs, the Alcoa demand will be reduced and when the utility demand is minimum, Alcoa's consumption will increase. The overall demand from the plant will be nearly constant. TVA could seek out similar opportunities.

The options described above would

--decrease need for petroleum distillates,

--decrease need for additional peak generators and pump hydro storage facilities,

--increase load factors on base and intermediate load plants,

--increase utility and distributor capital investments for meter and control systems,

--increase investment and maintenance of customer-owned load management devices, and

--lower overall power costs.

FOOTNOTES

1/The White House, "The President's Energy Program", April 20, 1977; also Executive Office of the President, "The National Energy Plan," April 29, 1977.

2/U.S. General Accounting Office, "An Evaluation of the National Energy Plan," EMD-77-48, July 25, 1977.

3/"Industrial Energy Center," a report prepared for the Office of Energy R&D Policy of the National Science Foundation of the Dow Chemical Company, the Environmental Research Institute of Michigan, Townsend-Greenspan and Company, Inc., and Cravath, Swaine, and Moore, June 1975.

4/Sander E. Nydick et al., "A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries," A Report by Thermo Electron Corporation to the Federal Energy Administration, May 1976 (FEA Report #TE5429-97-76).

5/"Overview of Trends on the Electric Utility Industry," Westinghouse Corp. (March 1976).

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9/"The Potential for Cogeneration Development in Six Major Industries by 1985," Draft Final Report to FEA (Resource Planning Associates, Sept. 1977).

10/"The Potential for Electricity Generation as a By-Product of Industrial Steam Production in New Jersey," Report for the New Jersey Cabinet Energy Committee by R. H. Williams (Princeton University, June 1976).

11/The Oil and Gas Journal, April 3, 1978.

12/Letter dated 25 January 1977 from Martin Seneca, Jr., Assistant Administrator, FEA, for Conservation and Environment to A. J. Wagner, Chairman, TVA Board of Directors.

13/Statement of T. Laaspere before the Public Service Commission of New York, Case #26806, August 11, 1975, page 17.

14/"Peak Load Control Study - Summer of 1975," prepared by Arkansas Power and Light Co., Distribution Standards Section(October 6, 1975).

15/"An Analysis of TVA's Proposed Time and Day Rate Test," by N. McBride, (East Tennesseee Research Corporation, Jacksonboro, Tennessee, 1977).

16/See, for example, "Opportunities and Incentives for Electric Utility Load Management," report prepared for FEA Office of Industrial Conservation Programs, by Gordian Associates, Inc. (1975).

17/"The Challenge of Load Management: A Convergence of Diverse Interests," FEA Office of Utilities Programs (June 1975).

18/"Evaluation and Classification of Load Management Equipment," FEA Office of Conservation FEA/D-77-209 (June 1977).

19/"Time-of-Day Meterings: A Perspective of Peak Load Pricing," Electric Forum Magazine (Fall, 1975).

20/See, for example, "Electric Utility Rate Design Study: Rate Design and Load Management," Electric Power Research Institute (October 1976).

21/Private communication from C. W. Garrard, Jr., TUSI (Dallas) August 1977.

CHAPTER 6

THE PROBLEMS ASSOCIATED WITH

GENERATING ELECTRICITY

The many problems now associated with the generation of electricity makes the difficult choice between nuclear or coal fuel one of identifying the lesser of two evils.

NUCLEAR PROBLEMS

The eventual acceptability of nuclear power will depend on demonstrated solutions to such problems as radioactive release hazards, radioactive waste disposal, uranium availability, decommissioning, and capital cost escalations.

Radioactive release hazards

The most serious nuc ear accident envisioned is the instantaneous rupture of le largest coolant pipe which could result in a reactor core meltdown and a release of radioactive materials. The most thorough analysis of the probability of a reactor accident and its consequences is summarized in NRC's October 1975 Reactor Safety Study, commonly known as the Rasmussen Report, which found the risk of a major nuclear accident to be very small and well within the bounds of public acceptance. However, critics of the report say its accident probability assessments are speculative and that it neglected the potential for and effects of possible sabotage.

A 1977 report by the North Carolina Utilities Commission (NCUC) stated that over 1,000 reactor-years of worldwide operation without a core meltdown provides reassurance that the risks are minimal. The NCUC concludes that though the possibility of sabotage should not be discounted, there is no evidence that nuclear plants are more probable targets than facilities such as dams or skyscrapers. 1/ TVA agrees with the Rasmussen Report and NCUC's assessment. Nevertheless, the public's fear of a major accident must be overcome if nuclear power is to become a major source of energy.

Our April 7, 1977, report, "Securities at Nuclear Powerplants--At Best, Inadequate" (EMD-77-32), focused on the vulnerability of the commercially owned nuclear powerplants to sabotage, and the effectiveness of NRC to protect agair it. Our overall conclusion was that NRC has not operated effectively in the security area and, as a result, security systems at most powerplants would not be able to withstand sabotage attempts now considered minimum by NRC.

Regulations recently issued by NRC should remedy many of the shortcomings that now exist. However, because the regulations allow the utilities up to 1-1/2 years to comply with several significant provisions involving construction or installation of equipment, we believe immediate actions are necessary to increase interim protection at powerplants.

Radioactive waste disposal

During the atom splitting process, or nuclear fission, a commercial reactor or a reactor designed to create weapons-grade plutonium creates dangerous by-products. These wastes are classified as high or low level. The first is extremely radioactive and must be permanently isolated through techniques which would not require human surveillance for very long periods of time--from centuries to millenia.

The 65 commercial nuclear powerplants licensed to operate have stored spent fuel temporarily on site or at commercial storage facilities. The powerplants have a fixed capacity, and only one commercial facility is currently accepting fuel for storage. The problem is so critical that 44 nuclear plants at 33 sites have applied for or obtained permission to increase their onsite storage capacity. The lack of storage space for normal discharges in 1977 caused 6 reactors to operate without a full core reserve and could result in one reactor being shutdown in 1978 and as many as 12 by 1983.

DOE has begun a program to demonstrate, by the mid-1980s, the feasibility and safety of placing high level radioactive waste in deep geological formations. As we pointed out in a recent report, "Nuclear Energy's Dilemma: Disposing of Hazardous Radioactive Waste Safely" (EMD-77-41, September 9, 1977), progress has been negligible and program goals seem overly optimistic. There are many unsolved social, regulatory, and geological obstacles.

TVA and many other utilities believe radioactive wastes can be managed in a safe and environmentally acceptable manner. TVA officials feel the Federal failure to establish permanent disposal facilities has led to a public misconception concerning the Nation's ability to manage these wastes, which makes it difficult to plan for additional nuclear plants.

Uranium availability

Because the increasing concern about the adequacy of uranium supplies by the late 1980s, utilities have tried to contract for long-term deliveries but the scarcity of developed reserves in the United States limit long-term sales. As of January 1, 1975, arrangements had been made for meeting only the first core uranium fuel requirments for 61 percent of the reactors under construction or on order. Fuel arrangements beyond 3 years of operation are largely unsettled. TVA has negotiated for enough uranium to provide an adequate supply until 1984 and 65 percent of its needs through 1990. Requirements beyond 1990 are expected to be met by mining TVA owned and leased uranium reserves and through additional purchases.

TVA has mineral rights contracts covering about 600,000 acres in Michigan, New Mexico, South Dakota, Utah, and Wyoming. TVA's interests range from 25 to 100 percent and, in some cases, include options to obtain additional interest or purchase a larger shar of production.

Uranium enrichment operations

Before uranium can be used as a fuel for nuclear powerplants, it must undergo a complex process called enrichment. This process converts natural uranium into a mixture richer in the isotope uranium-235. An adequate supply of enriched uranium is essential to the continued growth of nuclear power.

There are three uranium enrichment plants in the United States, all owned by DOE. They provide enrichment services for all U.S. nuclear reactors, all Government research and weapons programs, and most foreign reactors. The future of uranium enrichment in the United States has been a controversial issue for the past several years. The debate over whether the next plant should be Government or privately owned received considerable attention. But on April 20, 1977, the President announced that the Government would build an addition to its Portsmouth, Ohio, plant using a new centrifuge process which is projected to require only 10 percent of the power requirements of the gaseous diffusion process. The expansion effort, however, will still require large quantities of electricity that suppliers may have difficulty providing. Actual capacity, therefore, could vary--depending on the electrical power supply.

DOE is currently obtaining electrical power for the enrichment plants from three suppliers--TVA, Electric Energy Incorporated, and Ohio Valley Electric Company. TVA has contracted to provide power to the Paducah, Kentucky, and Oak Ridge, Tennessee, plants into 1990, but some power through 1984 is under a "best-effort" contract that ties delivery to TVA's generating capacity. Electric Energy Incorporated also supplies power to the Paducah facility. Ohio Valley provides power to the Portsmouth plant under a contract which extends through March 1979. DOE plans to negotiate a second contract that will cover deliveries through the 1990s. The power for the centrifuge facilities is not yet under contract, but DOE does not anticipate any problems in purchasing this power.

DOE provides only the enriching services; customers must provide the uranium. As noted earlier, DOE's estimates of economically recoverable domestic uranium resources show that U.S. utilities will be heavily dependent upon unproven but expected uranium deposits. If these deposits are not as productive as expected, the uranium supply could fall short of demand.

Reprocessing

Reprocessing would involve removing spent fuel from nuclear reactors and reprocessing it to recover usable uranium and reactor-produced plutonium. According to an NRC estimate, commercial spent-fuel reprocessing could reduce the domestic uranium demand by about 22 percent through the year 2000.

There are no commercial spent-fuel reprocessing plants operating in the United States today. On April 7, 1977, the President announced that commercial reprocessing would be indefinitely deferred because of its proliferation implications. Therefore, it is unlikely that reprocessing will have any impact on the demand for uranium in the near future.

Decommissioning

Nuclear power reactors, which have an estimated operating life of about 40 years, involve major decommissioning problems because of their enormous size and their high levels of induced radioactivity. There are generally four recognized methods: dismantlement, entombment, mothballing, and a combination of either entombment or mothballing with subsequent dismantlement.

Dismantlement involves the total removal of the facility from the site to radioactive waste burial grounds. The land is then restored to its original condition and released for unrestricted use. The largest problem involved in immediate dismantlement is the protection of the workers and, therefore, much of the cutting of reactor parts must be done by remote-controlled, underwater, equipment--a costly and time-consuming process.

Entombment consists of sealing the reactor with concrete or steel after all liquid waste, fuel, and surface contamination have been removed and sending it to fuel storage facilities where security systems protect against intrusion. This approach requires annual checking for radiation leaks and periodic maintenance to insure the integrity of the entombed structure.

Mothballing is simply removing the fuel and radioactive waste and then placing the facility in protective storage. A mothballed facility requires a security intrusion system, annual radiological surveys, and periodic maintenance.

The fourth method is a combination of either mothballing or entombment with subsequent dismantlement. This approach offers the advantage of placing the facility in an entombed or mothballed status for about 65 to 110 years--until the induced activity decays to a level which permits dismantlement without undue radiation dangers. The entombment and mothballing methods and, to a lesser extent, the combination methods, would limit the use of the affected land. TVA and other utilities believe that the technology exists to decommission nuclear plants safely.

In a June 16, 1977, report to the Congress, "Cleaning Up the Remains of Nuclear Facilities--A Multibillion Dollar Problem" (EMD-77-46), we supported the combination of mothballing and delayed dismantling. The Atomic Industrial Forum estimated this method, including security forces, would cost $35.8 to $39.4 million in 1975 constant dollars. We concluded that the cost of decommissioning should be paid by the current beneficiaries instead of future generations, and we recommend that DOE make advance planning for decommissioning mandatory at the time of licensing, including provisions for funding.

TVA has not prepared a specific plan for decommissioning its plants, and it is not accumulating funds specifically for decommissioning. The normal depreciation rate has been increased to cover the anticipated cost of decommissioning, but the revenue is reinvested in the TVA system. A decommissioning proposal will be prepared and submitted to NRC for approval near the end of the plants' useful lives.

<u>Capital cost escalation</u>

TVA's experience in constructing nuclear plants has been similar to other utilities. As shown below, the total cost of TVA's first five nuclear plants has risen from the estimated $3.3 billion to $7.9 billion, an increase of 139 percent. The costs of the remaining two plants have risen about 13 percent and, based on previous experiences, their costs will continue to rise.

TABLE 6-1

Capital Cost Escalations of TVA's Nuclear Plants

Nuclear plant	Original estimate	1977 estimate	Cost increase	Percent increase
	------	(millions)-	-----	
Browns Ferry	$ 392	$ 920	$ 528	134.7
Saquoyah	336	1,100	764	227.4
Watts Bar	500	1,075	575	115.0
Bellefonte	650	1,300	650	100.0
Hartsville	1,425	3,506	2,075	145.6
Total--First five plants	$3,303	$7,895	$4,592	139.0
Phipps Bend	1,600	1,800	200	12.5
Yellow Creek	1,900	2,150	250	13.2
Total--all plants	$6,803	$11,845	$5,042	74.1

Source: TVA

The increases shown in table 6-1 result from the combined effects of delays in project operation schedules, regulatory additions, extreme inflation, and higher interest rates. Any reductions in the present 10-year cycle would reduce capital costs and enable TVA and other utilities to begin recovering the cost of their plants.

NRC has implemented some administrative changes. DOE has introduced legislation intended to reduce nuclear plant leadtime to about 6 years. But in a report to the Congress, "Reducing Nuclear Powerplant Leadtimes: Many Obstacles Remain" (EMD-77-15, March 2, 1977), we concluded that NRC's efforts have had little impact and that proposed programs will not appreciably reduce the present 10-year leadtime. In fact, we believe that both DOE and industry will have difficulty in maintaining the current timeframe.

PROBLEMS WITH COAL

The NEP anticipates an annual coal production of 1.2 billion tons by 1985, up from 665 million tons in 1976. Greater use of coal will entail some compromises. There are tradeoffs to be considered, balances to be struck, and prices to be paid. In the following sections we discuss

--the potential limitations of supply,

--the environmental effects of extracting coal, and

--the effects of burning coal on air quality.

TVA is the largest single purchaser of steam coal in the United States and it currently burns about 38 million tons of coal a year, about 10 percent of the total tonnage burned by domestic power producers. It has acquired mining rights to about 730 million tons of recoverable coal, and has several coal companies currently under contract to mine them.

Environmental effects of extracting coal

Both surface and underground mining disturbs the surface, produces wastes requiring disposal, affects water resources, and exposes materials that produce acids when combined with air and water. In surface mining, the major problem is surface disruption. Reclamation normally involves smoothing out piles of overburden and attempting to revegetate the area. Comprehensive programs include restoring the surface topography, replacing the mined topsoil, and fertilizing and revegetating the land--in short, returning the land to some productive agricultural, commercial, residential, or recreational use. The problems associated with underground mines are somewhat different. Reclamation is directed toward controlling subsidence and mine drainage, disposing of waste materials mined with the coal, and extinguishing coal fires.

TVA began including reclamation provisions in its contracts for surface-mined coal in 1965. These provisions were strengthened in 1968, 1970, and 1971. Because it is one of the few major purchasers to require reclamation, TVA has advocated Federal control of reclamation. In August 1977, the Surface Mining Control and Reclamation Act (Public Law 95-87) was passed, establishing a nationwide program for protection from the adverse effects of surface coal mining. The requirements of the act are not significantly different from TVA's contract provisions except that they require that the land be returned to approximately its original contours. TVA took the position that the future land use should be considered and that contour changes should be permitted if a desirable use requires it.

Current technology and planning cannot solve all the after effects of mining economically; specifically acid mine drainage, land subsidence, denuded lands, and hydrologic disturbances. Given the specific level of coal development that may be necessary to meet energy needs, the Nation must decide to what degree these environmental consequences will be acceptable.

Air quality

Coal combustion emits a number of substances that, at certain levels, have been associated with increased incidences of respiratory disease and related deaths, crop damage, the loss of domestic animals and wildlife, and the deterioration of building materials. At present, Federal and State laws seek to control only certain coal pollutants: sulfur oxides, nitrogen oxides, and particulate matter.

The disposal of large volumes of sludge collected in stack gas scrubbers which control sulfur dioxide emissions is an added problem. In our work on coal development, we estimate if controls are used, about 230 million tons of solids could result in 1985. 2/

There are also certain coal emissions not currently regulated which may be regulated in the future. The particulate control technology presently in use is only partially effective in preventing the escape of fine particulates (1 micron or smaller) which are widely believed to pose a special health hazard because of their ability to penetrate the respiratory system. Present regulations do not control other probably dangerous pollutants such as the trace elements of mercury, lead, beryllium, arsenic, fluorine, cadmium, and selenium emitted in coal combustion.

Most acidic sulfate air pollution is attributed to coal combustion. Control may involve not only regulating sulfur dioxide particles but also controlling its precursors, such as fine particulates and nitrogen oxides. EPA projects the sulfate levels in 1990 as similar to those of 1975--a level which still may cause serious health problems as well as the acid rains which harm plant and animal life.

In 1976, nine TVA-owned coal-fired powerplants failed to comply with the clean air regulations. 3/ Six related actions resulted in proposed Consent Decrees * which will rectify this situation. As of September 1978, the proposed decrees indicate that TVA

--admits the longstanding violations,

--agrees to the final sulfur limitations summarized (by powerplant) in table 6-2,

--agrees to a firm schedule of interim controls,

--subjects itself to specific sanctions for failing to meet any of the requirements of the decrees, and

--consents to build FGD scrubbers and/or use lower sulfur coal for 3,183 MW of its coal-fired plants.

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* State of Alabama ex rel Baxley, et al. TVA, et al., Civil No.: 77-P810-NE (N.D. Ala.). Tennessee Thoracic Society, et al. v. Wagner, et al., Civil Nos.: 77-3285, 3388, 3389, 3390, 3394 - NA-CV (M.D. Tenn.).

TABLE 6-2

Elements of the Proposed Settlement (note a) of the Clean Air Action Brought Against TVA by Nine Environmental Groups:

Emission Limitations and Schedules

Powerplant	Final limit (Pounds of SO2 MBTU)	Date of compliance	Compliance method
Allen	4.0	2/01/79	Eastern medium sulfur coal
Colbert	4.0	8/01/79	Eastern medium sulfur coal
Cumberland	5.0	11/15/81	Coal washing
Cumberland	4.2	12/31/82	Number of modules to be determined; (note b) coal washing
Gallatin	5.0	11/01/78	Eastern medium sulfur coal
Johnsonville	3.4	12/01/82	Five 150 MW scrubbers (one module will be redundant) eastern medium sulfur coal
Kingston	2.8	7/01/79	Eastern medium sulfur coal
Paradise			
Unit #3	5.7	6/01/81	Coal washing
Unit #1	0.9	4/01/82	Coal washing, 6-150 MW scrubbers (one module redundant)
Unit #2	0.9	7/01/82	Coal washing, 6-150 MW scrubbers (one module redundant)
Plant	3.1	7/01/82	Coal washing, 12-150 MW scrubbers (two modules redundant)
Shawnee	1.2	10/01/81	Eastern low sulfur coal
Widow's Creek	1.2	9/01/81	4-144 MW scrubbers on unit 7; (note b) eastern low sulfur coal on units 1-6

a/Proposed settlement by Consent Decrees.

b/One 5[illegible]-MW scrubber is already installed at Widow's Creek.

Source: TVA

Carbon dioxide also remains unregulated. Its build-up could cause global weather changes. If the use of coal continues to grow the climatic effect may be an important problem during the next 50 years.

There are serious questions about the wisdom of an increasing reliance on coal and the uncertainty is magnified by the lack of substantial knowledge of the long-t[illegible] effects of trace elements and other currently uncontrolled emissions.

PROPOSED ROLES FOR TVA

Using TVA's demand projections, power capacity must be added despite the problems associated with nuclear and coal fuels. TVA already has 12 conventional coal-fired plants in operation. These facilities and TVA's expertise, make the agency an appropriate national leader in demonstrating ways to reduce the adverse effects of producing electricity from these sources.

The NEP indicated a greater reliance on coal in the future. TVA, which consumes about 14 percent of the coal used to produce electricity in the United States, offers an excellent testing ground for developing solutions to the serious problems associated with the mining and burning of coal. However, such technologies as advanced flue gas desulfurization would involve various risks and TVA might require outside funding.

This section [illegible]usses levels of funding necessary for demonstrating several important fuel options and the effect of each on primary energy requirements and on the environment. Several innovations could make coal more acceptable to the general public:

--Bringing existing coal-fired plants into compliance with the Clean Air Act.

--Installing FBC in order to precipitate the electric industry's acceptance of FBC.

--Negotiating coal contracts to produce a percentage of TVA's coal requirements by 1985 from mines employing underground longwall mining technology in order to speed the acceptance of this safer, more efficient mining method.

As specific options for TVA, we will consider:

--The cost of complying with the Clean Air Act using three scrubber strategies at existing TVA coal-fired plants.

--The demonstration of FBC capacity by 1985.

--The costs and benefits of a major commitment to FBC after 1987.

--The costs and benefits of creating a market for underground longwall mined coal.

Scrubbers: a performance history of flue gas desulfurization technology

EPA has described several systems for scrubbing sulfur from the flue gases of coal and oil-fired powerplants. In the United States, there are 30 operating FGD systems and 86 under construction or planned. In Japan, 333 systems have been installed although most of these are on small oil-fired plants. All FGD systems produce waste, usually in the form of sludge, which must be solidified and disposed of. Sometimes the solidified sludge waste is usable as a landfill, although care must be taken to prevent leaching.

A variety of problems have plagued lime and limestone FGD systems: scaling, plugging, corrosion, and erosion of equipment parts. EPA believes that these problems can now be controlled. Lime and limestone systems now average 80-percent reliability with 80-percent sulfur dioxide (SO) removal efficiency. EPA points out that a 65 MW retrofit unit at the "Paddy's Run" station of the Louisville Gas and Electric Company has a reliability of nearly 100 percent. The excellence of this performance is partially due to the coal-fired plant, which burns 3.5 to 4.0 percent sulfur coal, mainly for peaking power, leaving it frequently shutdown. This procedure allows regular maintenance work on the scrubber, a critical factor in FGD performance.

EPA also points to the 820 MW scrubber at the new La Cynge station of Kansas City Power and Light as a large operating system with very good operating experience. This system is composed of seven modules which have an average reliability of 83 percent and a scrubbing efficiency of up to 80 percent. Maintenance remains a major problem with limestone scrubbers. Improved design should increase the reliability and efficiency of [illegible] scrubbers. Among the possible changes are using [illegible] resistant alloys or rubber linings in equipment and adding an extra module in order that one module can always be off-line for maintenance work. 4/

Options for FGD systems at TVA

A strong case can be made for TVA's demonstrating new FGD technology.

--TVA has to build scrubbing units on 3,183 MW of its coal-fired capacity.

--The proposed Consent Decrees indicate economic benefits to TVA totaling $260 million as a result of noncompliance. TVA tentatively agreed to construct 600 MW of scrubbers (five 120 MW modules) at its Cumberland Steam Plant.

--TVA electric rates have been lower than would have been the case had TVA complied with the Clean Air Act.

TVA could best serve the national interest (1) by choosing the most environmentally benign FGD systems, in spite of likely higher costs, thus setting the standard for utilities performance or (2) by demonstrating a wide array of FGD technologies, and thus helping develop or prove the reliability or benefits of these new systems. Several criteria must be applied in evaluating FGD systems, including

--cost,

--efficiency,

--reliability,

--energy intensity,

--by-product production (i.e., does the scrubber produce a salable end product or waste which must be disposed of, and can be environmentally damaging),

--utility experience with scrubbers, and

--reducing agents used to remove SO.

Table 6-3 describes the capital investment and operating costs (which includes amortized capital costs) of the leading FGD technologies. Note that the nonregenerable systems, which produce large amounts of potentially toxic sludge which must be disposed of, are the least expensive. Table 6-4 compares the relative advantages of several promising FGD technologies.

TABLE 6-3

Capital and Operating Costs of the Leading Flue Gas Desulfurization Technologies (For Existing Powerplant Retrofit)

Non-regenerable systems	Capital cost ($/kW)		Operating cost (mills/kWh)		By-product
	200 MW	500 MW	200 MW	500 MW	
Limestone	76.4	62.2	4.06	3.39	Sludge
Lime	87.6	70.0	5.11	4.15	Sludge
Double alkali	60.0	50.0	3.00	2.50	Sludge and gypsum
Regenerable systems					
Sodium sulfite	118.0	86.7	7.76	6.34	Elemental S, H_2SO_4 or liquid SO
Magnesium oxide	96.1	69.9	5.18	9.01	H_2SO_4
Aqueous carbonate (note a)	100.0	100.0	5.00	5.00	Elemental S
Aqueous Potassium (note a)	100.0	100.0	5.00	5.00	Elemental S
Copper Oxide (note a)	100.0	100.0	5.00	5.00	Elemental S

a/The capital costs are unknown but are not expected to exceed $100/kW and may in fact be considerably overstated. The operating costs are estimates only.

Source: James Herlihy, Flue Gas Desulfurization on Power Plants, Status Report, Washington, D.C., April 1977, and personal communication with EPA research staff, Research Triangle Park, North Carolina, April 1978.

TVA's new scrubber units will be chosen from among the systems described in table 6-4. For illustration purposes, the scrubbers TVA will need could be of the following number and size. Application could actually be of any combination of units that total 3,183 MW.

	Number	Size
	5	120 MW
	4	150 MW
	2	704 MW
	1	575 MW
Total	12	3,183 MW

TVA's approach to this massive building program can have a great influence on the future of FGD in American utilities. TVA could pursue three strategies to accomplish the above example.

The first, aimed solely at minimizing the cost compliance, would probably dictate a choice of double alkali systems for all units.

The second, providing maximum environmental protection (highest SO2 removal efficiency, avoidance of sludge on solid waste disposal, etc.), would call for the construction of magnesium oxide or sodium sulfite systems.

The third, providing the greatest development benefit to FGD technology, would have TVA building the widest array of scrubbing systems, including some which have yet to be proven on a 100 MW scale.

Table 6-3 provides cost estimates (capital and operating, as well as by-product credits) with which the three aforementioned strategies can be evaluated. Table 6-5 describes how the three strategies could <u>possibly</u> be composed in terms of the types of FGD units chosen along with the capital investment and annual operating costs. Note that the capital costs are amortized and included in the operating costs.

TABLE 6-4

Advantages and Disadvantages of Leading FGD Systems

System	Advantages	Disadvantages
Lime and Limestone	Low capital and operating costs	Sludge by-product
	Greater operating experience	Corrosion and erosion of scrubber equipment
Double alkali	High SO removal efficiency	Sludge and cake by-product
	High reliability	Little large-scale experience
	Adequate small-scale operating experience	
	Low(est) capital and operating costs	
	Most benign solid waste by-product	
Magnesium Oxide	Lowest capital and operating costs of the "recovery" or "regenerable" systems	Less experience than with lime and limestone systems
	Saleable by-product (sulfuric acid)	Uncertainty with regard to sulfuric acid market
	Very little sludge or cake to be disposed	Storage problems associated with sulfuric acid
	Greater experience (compared with other "recovery" systems)	Necessity of having regeneration facilities located nearby, or firm regeneration contact with stable company
	High SO removal efficiency	
Sodium sulfite (Wellman Lord)	Salable, easily stored by-product (elemental sulfur)	High cost
	High SO removal efficiency	Little experience on coal-fired powerplants
	High reliability (as experience in oil-fired powerplant applications)	Elemental sulfur reduction process (as currently practiced) requires natural gas
	Could potentially use carbon monoxide, coal, or other reducing agents for SO reduction to sulfur	

System	Advantages	Disadvantages
Aqueous potassium	Salable, easily stored by-product (elemental sulfur)	Has been tested only on 10 MW scale
	High SO removal efficiency	Regeneration process has been tested only on a laboratory scale
	Has been selected for small scale demonstration by EPA	
Aqueous carbonate (Atomics International)	Salable, easily stored by-product (elemental sulfur)	Coal is not a good re-reducing agency
	Economical petroleum coke is the reducing agency	
	Reduces all sulfates, thus diminishing water pollution	
	No corrosion problems have been reported	
	Significantly reduces SO particulates, and halogen gases	
	Relatively energy efficient	
Copper oxide	Can produce elemental sulfur	Engineering complexity
	Hydrogen or carbon monoxide may be used as reducing agents	High energy intensity
	Has been chosen for demonstration by EPA	Very little experience
		A large quantity of hydrogen gas for reduction is required

Sources: EPA, Herlihy, op. cit., T. Devitt, et al., "Flue Gas Desulfurization Systems Capabilities for Coal-Fired Steam Generators," prepared for U.S. EPA, Research Triangle Park, North Carolina, preliminary draft, November 1977; and "Flue Gas Desulfurization Systems: Design and Operating Parameters, SO Removal Capabilities, Coal Propertise and Rehead," Draft, Bechtel Corporation, prepared for U.S. EPA, Research Triangle Park, North Carolina.

TABLE 6-5

Three Strategies for Clean Air Compliance at TVA:
Least Cost, Maximum Environmental Protection
and FGD Demonstration

FGD Components	Total capital cost	Total annual operating cost (note a)	Annual (note b) by-product (cost) value
	---------millions of dollars-----------		
Least Cost			
All units, double alkali			
120 MW (5 units)	36	10.3	(4.8)
150 MW (4 units)	36	10.2	(4.8)
704 MW (2 units)	70	20.0	(11.2)
575 MW (1 unit)	29	8.2	(4.6)
Total	171	48.7	(25.4)
Maximum environmental protection			
Sodium sulfite scrubbers			
120 MW (5 units)	59	26.5	1.8
150 MW (4 units)	59	26.5	1.8
Magnesium oxide scrubbers			
704 MW (2 units)	98.4	50.8	8.9
575 MW (1 unit)	40.2	13.1	3.5
Total	256.6	116.9	16.0
FGD demonstration			
Aqueous carbonate 120 MW (1 unit)	c/12	d/2.4	.36
Copper oxide 120 MW (1 unit)	c/12	d/2.4	.36
Aqueous potassium 120 MW (1 unit)	c/12	d/2.4	.36

TABLE 6-5 Continued

FGD components	Total capital cost	Total annual operating cost (note a)	Annual (note b) By-product (cost) value
	---------millions of dollars-------------		
Sodium sulfite 120 MW (1 unit)	14	5.3	.36
Limestone 120 MW (1 unit)	9	2.8	(.96)
Magnesium oxide 150 MW (4 units)	58	13.7	.90
Double alkali 704 MW (2 units)	70	20.0	(13.6)
Sodium sulfite 575 MW (1 unit)	50	20.7	1.7
Total	237	69.7	(8.12)

a/Includes amortized capital investment.

b/A cost is the charge for disposal of sludge; a value is the dollar value of a salable by-product. Elemental sulfur is assumed to sell for $40/ton; sulfuric acid for $25/ton.

c/These costs are unknown. It is not expected that they will exceed $100/kW, however, in fact, they may be considerably overstated.

d/Estimates only.

Source: See table 6-4 and Wade H. Ponder, Richard D. Stern, Industrial Environmental Research Laboratory, EPA Research Triangle Park, North Carolina, and Gerald G. McGlamery TVA, "SO2 Control Technologies, Commercial Availabilities and Economics," August 1976.

The net costs of the three strategies over 20 years (the assumed life of FGD systems) would be about $1.5 billion for the Least Cost, $2.1 billion for the Maximum Environmental Protection, and $1.6 billion for the Demonstration.

As a national yardstick and leader, TVA's most productive action would be to follow the maximum demonstration and development of FGD technology. Demonstration of the more advanced FGD technologies could require more time than anticipated or could prove to be unacceptable. Therefore, TVA might not meet the compliance dates of the proposed consent decrees. Because of the desirability and need for this demonstration program, TVA could negotiate specific allowances with the courts and plaintiffs to recognize and make suitable exceptions for developing advanced FGD systems. The added cost above that of the Least Cost strategy should be paid from appropriated funds because of the benefits to be derived by the Nation and the potential risks to TVA.

Fluidized Bed Coal Combustion

The most significant contribution TVA could make in the area of coal combustion would be to encourage widespread acceptance of fludized-bed combustion. FBC offers the possibility of cleaner and more efficient coal combustion for electrical generation. As mentioned previously, the adaptation of flue gas desulfurization technology to existing TVA coal-fired capacity would reduce the effective capacity of the TVA system by nearly 160 MW. Replacement of this lost capacity by federally subsidized fluidized bed boilers could be very attractive to both TVA and the Nation. In the following pages we will discuss FBC technology and estimate the costs and benefits of fluidized-bed boilers in the 1985 time range and to the year 2000.

Fluidized-bed combustion burns a fuel which has been mixed with some inert material and expanded (fluidized) into a relatively thick layer by the passage of air through it. The air flow rate and the particle size of the solids determine whether the bed stays fixed as a porous layer or behaves like a boiling fluid. At higher air velocities, the solids remain suspended in the gas stream and are carried out the furnace. When the gas flow rate reaches the critical point, the "fluidized velocity," the pressure drop across the bed is equal to the weight per unit area of bed. At a gas velocity of three to five times the fluidized velocity, the bed behaves like a violently boiling liquid. The boiling action provides a higher degree of particle mixing and circulation with the exposure of a large surface area by the particles. Thermal equilibrium between the gas and the particles is reached rapidly.

The fluidized-bed combustion system employs coal particles and limestone sorbent. Air for combustion is blown into the chamber from the bottom at such velocities that the solid particles behave as a fluid and mix homogenously as the reaction occurs. The limestone, or dolomite, reacts with the SO2 produced during the combustion to produce calcium sulfate which is removed with the ashes. This eliminates the need for removal of sulfur oxides from the stack gases, encouraging the use of high sulfur coal located near major consuming centers.

The fluidized-bed reactor has other advantages which are less obvious. Heat transfer to tubes immersed in the bed is very efficient; therefore, the combustor units can be smaller than boilers using air-supported combustion.

The alkaline waste of coal ash and spent limestone, partially converted to calcium sulfate has the potential application of a soil conditioner. The waste is reported to have excellent self-setting properties which would minimize the water penetration and reduce leaching of a refuse dump. The waste can be used as a soil conditioner or the lime regenerated from the waste by several methods. The recovered SO2 can also be used for production of sulfuric acid if a commercial market exists.

Fluidized-bed combustors are distinguished by two varieties: "atmospheric" combustors where the air is supplied to the bed near atmospheric pressure and "pressurized" combustors where the air is supplied at up to 10 atmospheres. In the pressurized version, the bed is much thicker and the increased air flow comes from a compressor powered by a gas turbine driven by exhaust gases. Tests conducted thus far indicate that corrosion and ash deposits on the turbine blades are manageable problems. A cyclone separator reduces the ash content of the gas and recycles charcoal to the combustor. Electricity, in either case, would be generated by a conventional steam turbine and alternator combination.

Fluidized-bed combustors have been used commercially for roasting pyrite ores of various types as well as for burning low-grade waste such as sawdust and sewage sludge. Despite the operation of a number of experimental steam boilers over the past 20 years, there are no operating commercial electric generating plants now utilizing fluidized-bed combustion. A demonstration plant of 30 MW has been built at Riversville, West Virginia, and is now in the testing and operating stage.

The U.S. fluidized-bed combustion program is being conducted largely by DOE, with some involvement by private industry, universities, and international groups.

According to the following excerpt 5/, the U.S. FBC program presently is geared to <u>industrial</u> application by about 1985.

> "The current technical program of ERDA in fluidized-bed combustion seem to be adequate to allow implementation of the process by industrial users by the year 1985. This is contingent on the continued technical success of the fluidized-bed combustion technique through the demonstration stage. In order for fluidized-bed combustion to be implemented as a source of power and steam by industry, the process must first prove itself to be absolutely reliable; and secondly, it must have a competitive edge over other coal utilization processes, both from an operating and capital-cost standpoint. These, of course, must be shown in a timely manner at an early date because timing is of utmost importance."

Another recent paper 6/ for the National Coal Policy Project recommended that

> "(FBC) be sped up as much as possible * * * [and that] * * * functional (FBC) demonstration plants * * * be built as soon as possible to show [illegible]ility to the industries involved."

The paper estimated that atmospheric fluidized-bed systems would be commercially available by 1984, but that pressurized systems would not be available commercially until 1988. TVA could do much to speed the acceptance of FBC.

In constructing commercial scale atmospheric FBC in the TVA system by 1985, TVA could help resolve problems of the technology such as:

--Feed system breakdowns in both atmospheric and pressurized beds.

--Fouling, corrosion, and erosion of parts of the gas turbine of pressurized beds. Materials and equipment that can hold up under exposure are yet to be developed.

--Difficulties in load following capabilities and in the ability to turn the beds down.

--Early cost comparison of FBC and conventional coal-fired capacity with FGD.

Because of the unresolved problems, purchasing unproven commercial scale technology would present a risk of sizeable proportions to TVA customers and could, therefore, be funded similar to the cogeneration projects described in chapter 5.

Long-range commitment to FBC

The successful demonstration of commercial scale fluidized bed combustion by 1985 could serve not only to create a climate of confidence in the electric utility industry but provide information for making possible a full scale commitment by TVA to FBC technology.

Coal purchasing policies--
longwall mining

Surface mineable coal accounts for only about 5 to 15 percent of the recoverable U.S. reserve, but accounts for more than half of the current coal production. President Carter, in his NEP expressed a desire to have the coal mining industry place more emhasis on underground mining. The most promising technique is longwall mining.

It involves a panel of underground coal usually about 450 feet wide, 5,000 feet deep, and 30 inches to 8 feet high. Huge drum-shaped cutting heads called shearers travel the length of the coal seam's face, grinding out coal and dumping it onto a conveyor which hauls it outside. The miners work under a protective canopy of steel supported by jacks or props. As the shearers complete a pass, they, with the conveyor and canopy, are moved forward and the roof behind caves in. Longwall mining is faster, cheaper, and safer than other underground mining methods. The coal-recovery rate is much higher and the product is cleaner.

Longwall mining is used almost exclusively in underground mines in Britain, West Germany, Poland, and elsewhere. The first modern working face was installed in the U.S. in 1960 but its growth here has been slow. According to Coal Age 7/, longwalling accounted for less than 4 percent of underground production in the United States during 1975. This figure is expected to move upward to 15 percent by 1985.

Longwall mining is very promising because (1) productivity per worker is greatly increased, (2) the percentage of coal recovered is greatly increased, and (3) health and safety of miners is enhanced by better ventilation and better roof supports. The primary barrier to longwall mining is an initial capital cost, of up to $10 million. Another obstacle, particularly in urban areas, is land subsidence.

Where good physical conditions exist, longwalls produce 70 to 90 tons per worker day compared with averages of 10 tons in conventional room-and-pillar mines and 36 to 45 tons in surface mines. The effect of this tremendous increase in productivity is to cut labor cost proportionately. Recovery as high as 90 percent has been projected by the Bureau of Mines and 70 to 80 percent is now common on 500-foot faces. This compares with a recovery rate of about 55 percent from the average room and pillar mines. (Because of the vast investment required to develop and extract coal reserves, any increase in the recoverable tonnage will lessen the investment per ton.)

An official of the U.S. Mining Enforcement and Safety Administration evaluted the health and safety benefits of longwall coal mining in the following words:

> "Longwalling is the easiest way for an operator to get in compliance with the law, and to stay in compliance. It solves the roof problem and it's a big boost for good ventilation. When an operator has those two conditions under control, he's well on his way to meeting all the relevant safety laws of the land."

The improved ventilation of longwall mining reduces the incidence of respiratory diseases. An analysis of Pennsylvania Mine Corporation's records shows that longwalling accounted for 30-percent production but only 16.2 percent of the injuries, which were notably less severe than injuries in room-and-pillar mines. National statistics are similar.

One of the most formidable obstacles to longwall mining is the capital cost. If development work is included, initial investments often reach $10 million. Of this amount, equipment costs about $3 million with a useful life of about 15 years and the remainder is for mine development. One rule-of-thumb suggests that only mines capable of producing one million tons per year should be considered for longwalling. The size must permit processing to keep pace with extraction.

Surface subsidence can be a major problem in longwalling in areas that are becoming increasingly urbanized. An offsetting factor, however, is the fact that longwall mining can produce a more uniform and predictable subsidence than room-and-pillar mining. The uniformity of subsidence due to completeness and spread of extraction and the predictability of setting, also eliminate the time bomb problem of unexpected subsidence occurring long after mining has ceased.

However, many U.S. coal operators have reservations about being able to manage underground mines of the size needed. Two longwalls operating 70 to 75 percent of the available time could push some companies to the limit.

TVA could boost longwall mining by favoring mine operators using this technique. It could help overcome the capital cost problems by assuring an adequate market for a number of new mines.

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CHAPTER 7

SOLAR DEMONSTRATION POTENTIAL IN THE TVA REGION

TVA could provide an important and convenient laboratory for applying and demonstrating solar energy technologies. Although the low price of TVA electricity (30-percent below the national average for residential customers) appears to make solar less attractive in the TVA region, there are fewer institutional problems discouraging its use there. Zoning restrictions, high population density (which limits the availability of land), and possible disincentives from private utilities are minor or nonexistent in the TVA area. TVA also has the personnel and institutional framework in its Power Utilization Division to promote solar use. This section of the Office of Power already provides incentives and technical assistance to encourage the purchase and installation of heat pumps by builders and homebuyers and the construction of "Super Saver" homes. Other resources, such as Government financial incentives, would be needed to test and demonstrate solar systems which are not yet competitive.

In this report, solar energy options we examined are divided into four categories: solar-passive building design, water heating (residential and industrial), and space heating. Solar passive design of buildings and in landscaping maximizes winter sun heat gain, minimizes winter heat loss, and minimizes summer heat gain. The simplest form provides south-facing window areas with proper shading. Water heating is the simplest form of active-solar utilization. Solar heating and cooling systems are complicated and capital-intensive, and they usually require conventional back-up systems. Water and space heating systems consist basically of flat-plate collectors through which water or air is pumped, a storage tank, circulating pump, and connecting piping. One promising hybrid is the solar assisted heat pump system.

SOLAR PASSIVE BUILDING DESIGN

The most significant energy demands in the residential and commercial sectors may be expressed as a percentage of total demand. They are space heating--53 percent, water heating--24 percent, and air conditioning--7 percent. Space heating requirements can be significantly reduced from an estimated 12 to 50 percent by intelligent solar-passive building design. 5, 6/ Prime considerations include building orientation, shading, wall exposure, and building materials.

In summer, the sun shines on a house from the east in the morning and west in the afternoon; but in the winter the sun never gets very high and shines primarily from the south. Good passive design requires wide eaves on the east and west to shade summer sun, windows on the south to capture winter sunlight, and deciduous trees on the east and west sides which shade in the summer but not in the winter. Other shading factors that affect heat gains or losses include curtain fabrics, other window coverings, and types of window glass. Building orientation, window placement and type, and various shading alternatives have significant impacts. 4/

Wall exposure is usually expressed as a ratio of the north-south to east-west wall lengths. Increasing the north-south wall length increases heat loss, while increasing the east-west exposure increases heat gain. Optimum ratios vary regionally and should be calculated and applied to new construction within the region.

Appropriate building materials and external colors can provide substantial benefits. Exterior white paint reduces the demand for air conditioning in the TVA region. Materials can be chosen which deliver external heat to the inside living space in different time intervals. An optimum time interval would be about 18 hours; the high temperatures from the preceeding noon would radiate inside during peak demand when residents are getting up for the day. The commonly used asphalt-on-concrete roof is undesirable because summer heat is transmitted into living space at a time coinciding with the heat generated by cooking dinner. 4/

The average cost per household of incorporating solar passive design into space heating and cooling has been estimated at $450 to $1,000. 5, 6/ The average annual heat savings would amount to between 12 and 50 percent. The lower range of this estimate would average 7.5 MMBTU annually, the equivalent of more than 1,000 kWh. Incorporating solar-passive design into the 750,000 new households TVA has projected will be built in the region by 2000 could result in savings of more than one half billion kWh per year at an estimated cost of $5.20/MMBTU. This compares with $6.50/MMBTU for residential electricity costs in the valley. More importantly, perhaps solar-passive design benefits would have been demonstrated to the Nation.

SOLAR WATER HEATING

Solar water heaters can consist of simply a collector, a tank, circulating pump, and connecting pipes. Solar water heating systems for existing water heaters would require two tanks. The additional tank would be used for tempering and would be located on the water line ahead of the existing water heater as shown in figure 7-1. 5/ Solar water heating of new construction would require only one tank as illustrated in figure 7-2. 5/ The single tank system would require an auxiliary electric heating element which would be thermostatically controlled.

The cost of retrofitting an existing system might be as high as $2,000 per household, while new systems should range between $1,200 and $1,500 although this cost should decline as manufacture of these units increases and becomes more efficient. Those estimates, in 1975 dollars, would be about $7.50 a MMBTU as compared with TVA residential electric rates of $6.50 a MMBTU. Thus, solar water heating is very near the point at which it becomes cost effective when compared with the average price in the TVA region, and has already reached that point elsewhere in the Nation. Annual savings in an average household should be about 2,400 kWh or about 16 percent of demand in an average residence in the TVA region. If all new homes (750,000 by the year 2000) installed solar water heaters, an annual savings of 1.8 billion kWh could be realized.

To promote residential solar water heating, TVA could analyze various alternatives such as interest free loans or subsidies since the cost of solar water heating systems would be less than replacement costs for new generation capacity.

There is a large potential for industrial application of solar water heating. Table 7-1 is a sample calculation of how solar water heating from industrial application could be made cost effective. 5/ Before TVA begins demonstrating such a system, further study of applicability of these estimates to the TVA regions, as well as the location of an industry willing to participate in such a project will be necessary.

SOLAR HEATING

A solar heating system for a residence is presented schematically in figure 7-3. Average system cost has been reported to be $6,000 to $7,000. 5,6/ Annual energy production from a solar heating system should average about 28.7 MMBTU, though this would vary widely across the United States. One estimate of the cost of this heat is $14.50/MMBTU. 6/ Although each house built with such a system would conserve as much as half of the average household demand in the TVA region, the cost and other barriers (such as integrating

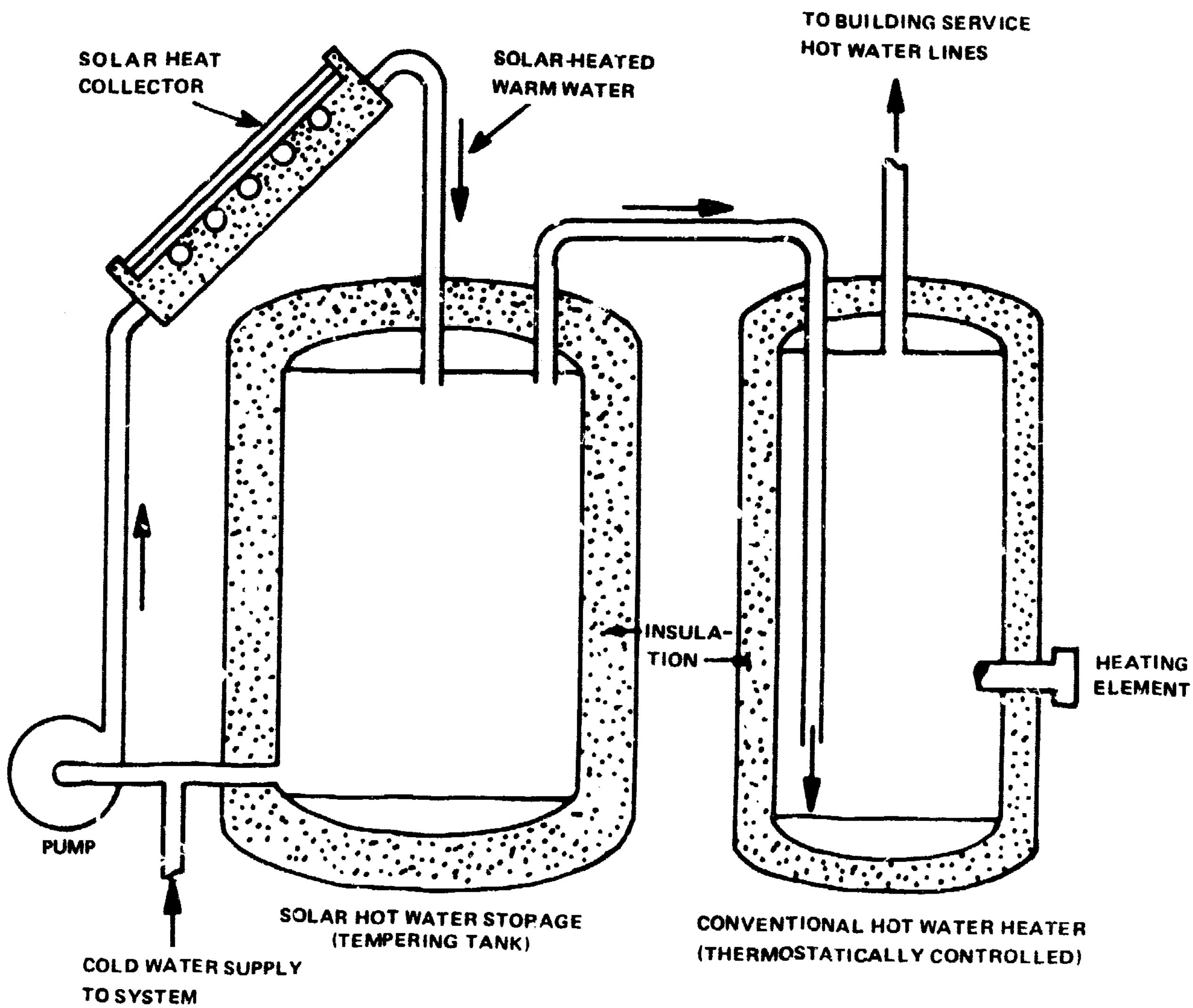

Figure 7-1: Hot water heating system, using solar storage (tempering) tank ahead of conventional fueled or electric service water heater.

Source: See Footnote 5.

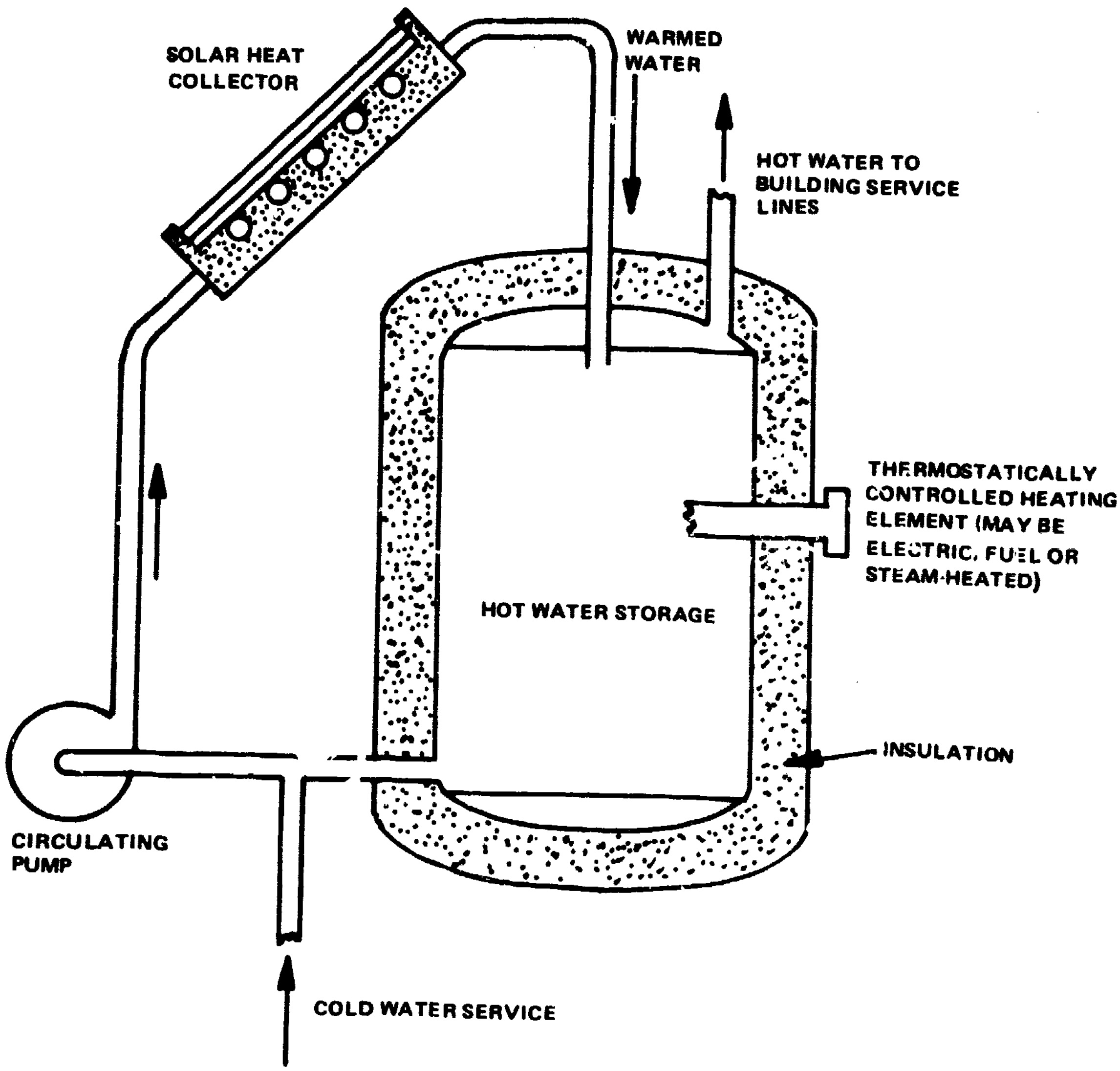

Figure 7-2: Single-tank system for hot water storage and heating system.

Source: See Footnote 5.

TABLE 7-1

Comparison of Annual Costs, Low Temperature Water Heating

Plan A (Fuel oil only)

Cost of oil	=$738,920
Boilers	
$60,000 x (crf, 8%, 20 years)=	6,110
Operation and maintenance	= 20,000
	$765,030

Plan B (50% Solar/50% Fuel Oil)

Cost of oil	=$369,460
Solar Facility	
$2,090,880 x (crf, 8%, 20 years)	= 212,960
Boilers	= 6,110
Operation and maintenance	= 40,000
Extra pump power	= 2,000
Added income tax	= 122,460
	$752,990

Cost of energy - $3.83/MMBTU

Cost of energy - $3.76/MMBTU

Conditions:

1. Annual requirement for process hot water = 200 billion BTU.
2. Annual contribution from solar facility = 100 billion BTU (50 percent).
3. Price of fuel oil = $15/bbl (assumes 70 percent conversion efficiency).
4. Area of solar collectors = 8 acres.
5. System Cost for Solar Facility = $6.00/ft . ($6.00/ft x 348,000 ft = $2,090,880)
6. Required rate of return on solar investment = 8 percent.
7. Straight line depreciation over 20 years.
8. No salvage value.

Source: See Footnote 5.

the system with conventional back-up systems) makes commercial applications currently prohibitive. 5, 7/

Additional research and development of these systems are warranted due to the high degree of potential energy savings (nearly half the average demand). Possibly in conjunction with DOE, TVA could pursue these systems to determine applicability and expand its acceptance if found feasible.

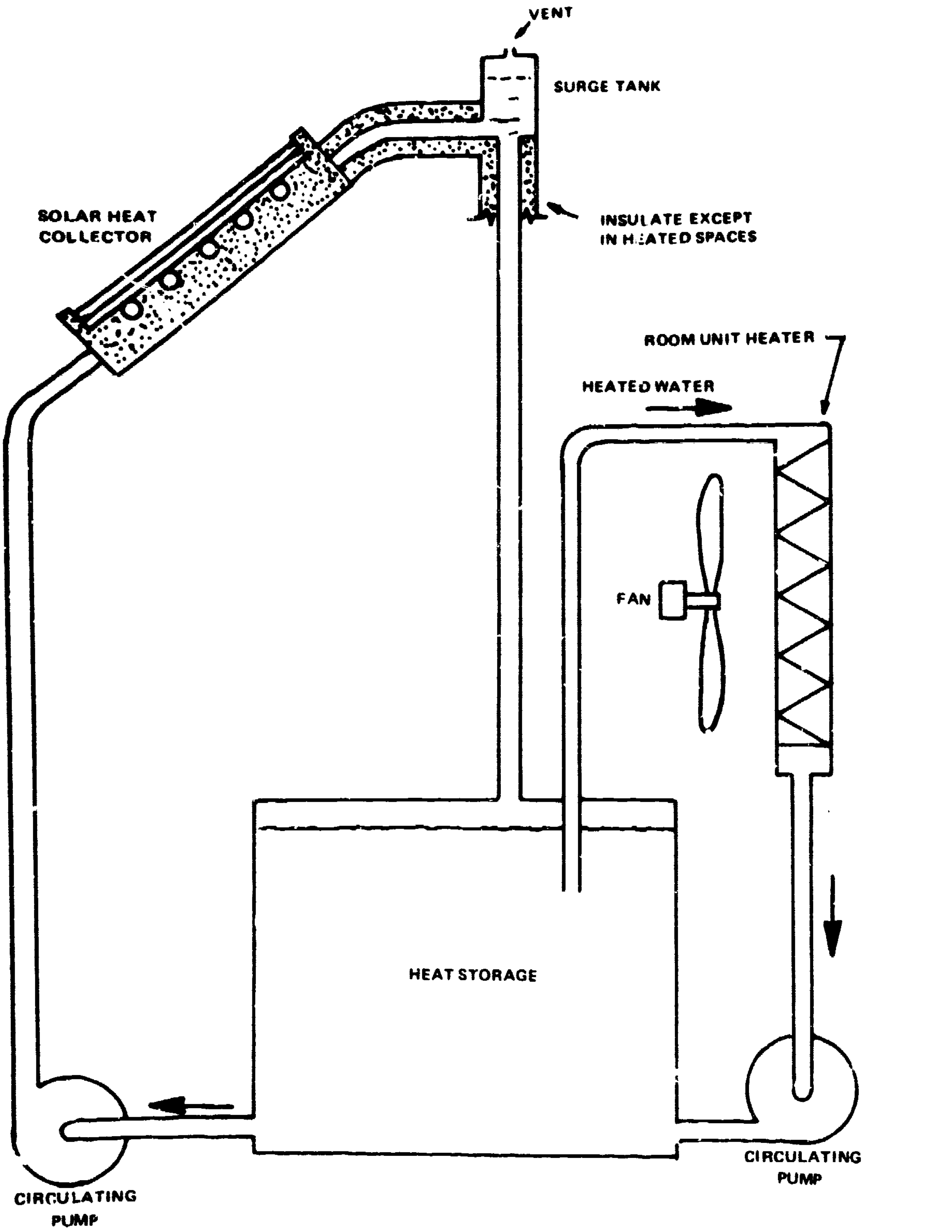

Figure 7-3: Minimum solar heating system, showing relationship of collector, storage, and room unit heater.

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CHAPTER 8

CONCLUSIONS AND RECOMMENDATIONS

This report has analyzed the roles that TVA can play as a Federal entity and the Nation's largest utility. The proposed coal strategy, industrial cogeneration, and solar programs will reduce total system requirements. The demand management strategy can significantly reduce peak load demand and alter the methods of producing power. If these options were to become reality, TVA's charter and its planning system would need to be changed.

CONCLUSIONS

TVA was purposely given a large measure of autonomy by the Congress. Its power program is self-sustaining. As a result of these two factors, the power program has been evaluated only on a few occasions and our review is the first major assessment made since 1959.

TVA has a congressional mandate to provide the widest possible use of power at the lowest feasible rate. TVA needs different goals and priorities if it is to reflect national energy goals and continue its historical role as an energy leader and "yardstick."

Many options exist for meeting the TVA region's needs for power other than a single focus on large central station nuclear construction. Completion of those plants presently under construction or licensed could, when coupled with a new efficiency in consumption, meet demand through the early 1990s. With expanded conservation, improved power management, and the use of renewable resources, our analysis shows the region could meet its power needs through 2000 without thermal plant construction beyond that now in the licensing process. Before making new commitments to thermal construction, time should be allowed for the development, implementation, and evaluation of other options.

To allow this, TVA could expand and improve its planning process. There is a critical need for a comprehensive, long-range power program plan extending at least 25 years.

Much of TVA's planning has been dependent on the Office of Power's annual load forecast. It is the basis for decisions on conservation impacts, size and timing of new generation facilities, and fuel purchase estimates. It must be as accurate as possible to avoid either critical power shortages or excess capacity. Our review of TVA's forecast and the development of our two alternative projections suggest the following:

--The data on which the TVA and GAO projection methodologies are based are incomplete and inadequate. Therefore, TVA should collect detailed data on the users and uses of electricity (e.g., equipment ownership by fuel and housing type and residential uses of different fuels for each end use, classified by various demographic and social characteristics). In particular, TVA should survey their residential customers to determine patterns of ownership for major household customers regarding household equipment, appliances, and housing units. They should also meter a representative sample of individual appliances in homes throughout the TVA region. This data should then be used in the development and application of more sophisticated, detailed, and flexible projection methodologies.

--TVA should develop several projections of residential electricity use rather than a single forecast. The implications of a single forecast is that future growth in electricity use is predetermined and cannot be influenced by TVA. As our projections suggest, TVA could exercise considerable influence on future trends in electricity use. Development of several projections would allow TVA and the public to evaluate the benefits and costs of alternative electricity "futures."

--Projections of electricity use are sensitive to assumptions on future electricity prices. Assuming that real prices rise at an annual rate of 1.0 percent (rather than remain roughly constant between 1975 and 1990) reduces the 1990 estimate from 56.3 to 51.6 billion kWh. This suggests the need to carefully examine the basis for TVA's assumption that real electricity prices will not increase between now and 1990.

--There is uncertainty regarding the values of key parameters, in particular, the price elasticity of demand, as well as rates of change of key variables. Recent studies indicate that the value of the price elasticity of demand for the TVA region lies between (-0.6) and (-0.1). Our analysis used these values as probable boundaries. However, further research is needed to establish more specific values for this and other critical parameters.

It is imperative that TVA abandon its present practice of issuing a single, unreviewed forecast based largely on extrapolation of historic trends. Such a process cannot reflect changing national goals nor does it allow TVA to lead in applying or demonstrating new technologies.

TVA has taken actions to improve its planning process, but these have not been endorsed by the Board of Directors. Consequently, the success of the planning process depends primarily on its acceptance by the individual managers and directors. This approach has sometimes resulted in conflicts in missions and overlapping of services. A formal long-range plan would help eliminate these problems, provide goals and priorities, and establish a means by which TVA could be evaluated and held accountable.

Such a plan should assess optional courses of actions, show what steps would be necessary to implement each, and what the costs and benefits of each would be. Actions should be analyzed in terms of cost effectiveness and their appropriateness in terms of TVA's "yardstick" function. The extent to which TVA should fund each should be considered. TVA should then choose one or more options and give its reasons for selection. The choice should be reviewed by as wide a spectrum of regional citizens and institutions as practicable and their comments considered in arriving at a final version of the plan.

In particular, it would be critical to have DOE's review and comment on TVA's plan to assure consistency with national priorities, with their comments included as an appendix to the plan, together with TVA's evaluation of these comments. When any option TVA selects is a research or development project that involves Federal funds, TVA should make sufficient project details available at DOE's request.

TVA could submit the final comprehensive plan to the President and the Congress. We could evaluate the plan, monitor its implementation, and report to the President and the Congress periodically. Congress would then be in a better position to plan any needed hearings. This process should result in better planning and a clear congressional mandate emphasizing the use of conservation and renewable resources.

Energy supply alternatives

The TVA region's present potential for industrial cogeneration is estimated at the equivalent of as much as two large nuclear units (1,200-2,300 megawatts). The potential estimated for the year 2000 ranges from 5,200-6,700 megawatts. Applications of available technologies and development of new ones by TVA could (1) provide hard data to establish expected high fuel efficiencies, (2) illustrate the benefits of utility-owned cogeneration systems, (3) indicate the level of social benefits to be realized tnrough utility development and the consequent savings to consumers, and (4) reduce the uncertainty and unfamiliarity regarding cogeneration technology and fuel.

If TVA pursued its opportunities and worked closely with those industries moving into the region, those planning expansion, and those replacing boilers, a great potential of cogeneration could be realized.

Coal and nuclear powerplants were the only alternatives currently considered by TVA for future construction. Both create serious problems of health, safety, and the environment which cannot be solved with present technology. TVA could help solve many of these energy problems.

Under the proposed consent decrees, TVA is to install FGD systems on 3,183 MW of coal-fired units between now and 1982. If it chooses to comply with the decrees at the lowest possible expenditure, the cost over the life of the scrubber system would be about $1.5 billion. The system used would produce large amounts of sludge which would have to be disposed of.

If TVA were to pursue a scrubber program which experimented with an array of FGD systems, it could provide demonstration benefits to the region and the Nation. Such a program could cost only about 7 percent more than the least cost strategy. Because of the risks to TVA and the benefits to the Nation, the additional costs of such a program could be federally funded.

The future of coal-fired plants in the TVA region depends, to a large extent, on the commercial viability and acceptance of FBC systems in the 1990s. TVA could play a proper and vital leadership role in demonstrating FBC technology in the relatively near future. We conclude that they should undertake it on a high priority basis.

Retirement of older coal-fired plants depends on the level of demand and capacity requirements. However, even under conditions of low demand, availability of an attractive alternative such as FBC could allow TVA to replace the older plants. This factor adds additional impetus to the need for rapid development of FBC systems.

In constructing commercial scale atmospheric FBC in the TVA system by 1985, TVA could help resolve problems of the technology such as:

--Feed systems which have led to breakdowns in both atmospheric and pressurized beds.

--The fouling, corrosion, and erosion of parts in the gas turbine of the pressurized bed systems. Materials and equipment that can hold up under exposure are yet to be developed.

--Difficulties in load following capabilities and the ability to turn the beds down.

--Early cost comparisons of FBC and conventional coal-fired capacity with FGD.

We believe that the probable benefits more than justify the need for TVA demonstrating atmospheric FBC now.

The successful demonstration of commercial scale FBC by 1985 could create a climate of confidence in the electric utility industry and provide information which might support a full scale commitment by TVA to FBC technology.

As the Nation's largest buyer of steam coal, TVA can encourage longwall mining of coal which is faster, cheaper, and safer than other underground mining methods when ecological conditions are suitable. A TVA coal purchasing policy for various mines using this technology would help overcome the high capital cost barrier. It is also consistent with the NEP goal of placing more emphasis on underground mining.

If TVA takes the lead in demonstrating any supply alternatives, the Nation will also derive benefits and, therefore, any added costs over and above traditional power costs should be federally funded. These added costs could simply be based on an analysis of TVA's incremental costs for new powerplant construction.

Energy demand alternatives

By exercising various options, TVA could (1) reduce the growth rate of energy demand, (2) make the existing power system more efficient, and (3) defer new generating systems. TVA's efforts in energy conservation and demand management have been little different than other utilities. TVA should show the benefits of demand options in residential applications, power management, and solar alternatives.

By implementing the three residential NEP programs (appliance efficiency standards, thermal standards for new construction, and several measures to encourage insulating existing residences), TVA could save electricity and reduce energy-related costs in area households. If all benefits and costs from 1977-2000 are discounted to 1977 dollars at a real interest rate of 8 percent, the net benefit to the region's households would be $90 million. (Fuel bills would be reduced by $690 million and the increase in capital cost for improved equipment and structures would amount to $600 million.) TVA could expand its two existing conservation programs, Super Saver homes and insulation.

TVA has also initiated a program encouraging heat pump installation and maintenance. This could be expanded to encourage heat pump installation in all new construction. Those with electric heating systems alone would decrease demand as much as 1.3 billion kWh and result in net savings of as much as $50 million.

Electricity consumption is sensitive to price changes. According to our analysis, a 1 percent increase in the real price of TVA electricity could lead to as much as a 15.7 percent reduction in residential demand by 2000. If the options discussed in this report and other TVA initiatives do not adequately reduce demand, TVA could still effect additional conservation savings by applying a surcharge or issue bonds that would result in similar impacts. The money received could then be used as incentives to further conservation and the use of renewable resources.

The power management strategy we considered involves influencing electricity demand to maximize the use of base load plants and to minimize the use of the much more expensive peaking generators.

Varying rates to reflect seasonal and time-of-day demands, the development of interruptible contracts and services, and the matching of variable loads in commercial and industrial sectors could reduce peaking power requirements.

Implementation of these desirable options would also reduce requirements for petroleum distillates, increase the load factors on base and intermediate load plants, and lower overall power costs.

The use of solar energy, through such applications as solar passive building design, solar water heating, and solar space heating could further reduce the demand for power. Passive building design alone (building orientation, shading, wall exposure, and building materials) could save 12 to 50 percent of average annual heat costs. The cost for design is estimated at $450 to $1,000 and if incorporated into the 750,000 new households projected in the region between 1975 and 2000, could save more than one half billion kWh annually by 2000 (more than 1,000 kWh per household).

Residential solar water heating costs about $7.50 MMBTU as compared with TVA's average residential rate of $6.50 MMBTU. Annual savings would be about 2,400 kWh a year per household or about 1.8 billion kWh for the region by 2000. Although not cost effective when compared with the average price of electricity in the TVA region, it costs less than electricity produced by new generation capacity. Therefore, alternative means of pricing, subsidies, and loans could be considered. Industrial applications of solar water heating have a large potential but need further study before commercial applications can progress.

In the TVA region solar, space heating and cooling is not currently cost effective in any situation. Additional research and development is warranted, however, because of a reduction in demand of nearly 50 percent.

RECOMMENDATIONS TO THE BOARD OF DIRECTORS, TVA, AND THE SECRETARY, DOE

To improve TVA's planning and decisionmaking process and to provide criteria by which TVA can be better evaluated, we recommend:

--TVA prepare a long-range comprehensive plan (minimum of 25 years) with specific short-term goals to be presented to the President and the Congress. This plan should be updated and submitted annually. TVA should obtain review of the draft plan from a wide spectrum of the regional population. DOE should review the plan to ensure that it reflects national priorities and does not duplicate research and development projects. TVA should include DOE's comments as an appendix with an evaluation of those comments.

We should evaluate the final plan, monitor its progress, and report to the President and the Congress periodically. The Congress would then be in a better position to plan any needed hearings.

--TVA should prepare several 25-year electricity demand projections emphasizing energy conservation and the use of renewable resources.

--TVA should collect more detailed information on all users and uses of electricity. For example, TVA should survey their residential customers to determine patterns of ownership for major household equipment, appliances, and housing units and meter individual appliances in homes throughout the region.

The following energy supply and demand alternatives should be undertaken by TVA and should be included in the comprehensive plan.

Energy supply alternatives

TVA should undertake a major application/demonstration of cogeneration technologies which could include:

--A coal-fired steam turbine system in the several tens of megawatt range.

--A gas turbine system in the 50-200 MW(e) range capable of using alternative fuels (i.e., no. 6 oil, methanol, residual fuel oil, etc.) in a cogeneration mode.

--A gas turbine system capable of using different fuels and designed for installation at smaller industrial locations (to answer important questions on the economies of scale).

--A fluidized bed gas turbine system coal-fired, coordinating its effort with the work of American Electric Power Company. In the AEP system, steam from the gas turbine is run through a steam turbine to produce additional electricity. However, the TVA demonstration should be of a size to demonstrate the capacity of feeding excess generation to the network and simultaneously producing process steam for industry.

--A fluidized bed gas turbine system fired by biomass, in particular, wood waste. This demonstration could be located at a major wood and paper products complex such as the one in Calhoun, Tennessee. It would show fuel cycles, alternatives to coal, concentrating on industrial and agricultural wastes, and perhaps, municipal waste.

For those demonstrations that exceed TVA's incremental cost per KW, Federal funding should be requested.

TVA should continuously assess the potential for new industry cogeneration projects and support industries with such potential, particularly those in newly developed industrial parks.

In complying with the proposed Consent Decrees, TVA should follow the maximum demonstration and development of FGD technologies in its coal-fired units, as proposed in chapter 6. Such a program could cost about $100 million more than simple compliance would require and would entail certain risks. We recommend, therefore, that TVA request an appropriation for those costs over and above simple compliance.

TVA should construct commercial scale atmospheric FBC. Because of the risks inherent in this unproven technology, we recommend that this demonstration be funded the same as the cogeneration technologies above. Upon successful demonstration of this FBC, we recommend that FBC be used to meet all major TVA power production facilities required through the year 2000.

TVA's future coal purchasing policies should include actively pursuing contracts with coal mine operators who are using longwall mining techniques.

<u>Energy demand alternatives</u>

Although TVA has recently expanded its conservation and demand management programs, it should extend or undertake the following options:

--Increase efforts to implement the NEP programs.

--In conjunction with the education and certification of heat pump installation and maintenance, actively encourage installation of heat pumps in all new construction.

--Study and implement seasonal and time-of-day rates.

--Expand the use of interruptible contracts, but offered on a regular interruption basis rather than an emergency.

--Initiate a program to switch off hot water heaters and larger air conditioners in peak hours.

--Evaluate and pursue opportunities for matching variable loads in the region.

To further decrease electricity demand, TVA should:

--Promote the use of solar passive building design with incentives such as design awards for builders similar to the heat pump and Super Saver home programs.

--Design a strategy similar to the above promotion for solar water heating. In addition, TVA should provide alternatives for making these systems economically competitive for the consumer (such as reduced rates) since they are less costly to the power system than adding new generation capacity.

--In coordination with DOE, participate in the research and development of solar space heating and cooling for applications in the region.

--If the above options and other TVA initiatives do not adequately reduce demand, TVA should consider applying a surcharge or issue bonds that would result in similar impacts to effect additional conservation savings. Money received should then be used as incentives to further other conservation and the use of renewable resources.

RECOMMENDATIONS TO THE CONGRESS

We recommend that the Congress revise TVA's charter to better reflect current national energy priorities. TVA should be charged with (1) leading the development of electricity management plans and programs, (2) encouraging energy conservation and the most efficient production and use of energy, (3) encouraging the use of renewable resources, and (4) assuring adequate public involvement in energy planning and policymaking.

We have recommended that TVA request certain funds to demonstrate the energy supply projects we identified that TVA should undertake. The Congress should favorably consider those requests.

AGENCY COMMENTS

We made appropriate changes in the report based on items pointed out by TVA and DOE on our draft.

TVA comments

The TVA Chairman indicated in his comments on our draft report (see app. III) that many of the programs we recommended TVA undertake, have either started or were planned during 1978. TVA is also pursuing other initiatives in its power program. We fully support these efforts and would expect that TVA's efforts, together with this report, will benefit both the region and the Nation in helping to solve energy-related problems.

In their comments, TVA disagreed with the need for a revised mandate at this time for TVA. We continue to recommend such revisions because:

--TVA's power program now represents over 90 percent of its total assets and the current mandate does not adequately reflect TVA's power functions, and

--although TVA is pursuing many of the options we propose, a congressional affirmation through a new charter would affirm that TVA's programs remain in that direction. Also, a revised charter would better reflect TVA's current and future power responsibilities, as the priority it should for both the region and the Nation.

DOE comments

DOE indicated in its comments on our draft report (See app. IV) a similar concern for the need of a revised mandate. DOE also questioned that responsibilities could conflict between their charter and TVA's. We recognize this possibility and, therefore, we recommended that TVA's long-range formal plan be formally coordinated with DOE and also reviewed by as many other institutions as practicable.

TVA'S DEMAND FORECAST

Planning throughout the Office of Power centers around the demand forecast. It is used to determine when, where, and what types of new generating facilities are needed; it is the basis for estimating fuel purchases and for developing conservation and load management programs. Both estimated costs of operations and estimated revenues from sales are based on it, and these affect decisions on cash flow, borrowing, and future electricity prices. Demand forecast figures are used in numerous internal documents, in submissions to other agencies, and in reports to the Congress.

TVA serves four types of customers: residential, distributor-served commercial and industrial, direct-served industrial, and Federal. A forecast is developed for each group and they are consolidated to formulate a system-wide forecast.

TVA's 1977 forecast predicts that from the end of 1976 through the end of 1990 the area's electricity requirements will grow at an average annual rate of 5.4 percent. The following table shows the actual 1976 level of demand for each consumer compared to the projected demand by 1990.

TVA Area Electrical Requirements For 1976 and 1990 by Consumer Type (TVA Forecast)

Consumer type	Actual CY 1976 demand (billions kWh)	Percent of 1976 total area requirements	Predicted CY 1990 demand (billions kWh)	Percent of 1990 total area requirements	Average Annual Growth Rate (1976-1990)
Residential	a/33.6	28.4	a/63.9	26.1	4.7
Distributor-Served commercial and industrial	a/31.3	26.5	a/79.8	32.5	6.9
Direct-served industry	23.5	19.9	43.0	17.5	4.4
Federal	22.0	18.6	40.7	16.6	4.5
Other (note b)	7.9	6.7	17.9	7.3	6.0
Total	118.3	100.0	245.3	100.0	5.4

a/Adjusted to normal weather conditions.

b/Includes TVA and distributor distribution losses, outdoor lighting, etc.

Residential forecast

In 1976, TVA's 2.3 million residential customers used about 33.6 billion kWh of electricity, 28 percent of the area's total requirements. They are served by 160 distributors who resell TVA power. Three methods are used in preparing residential forecasts.

In the first method, a TVA econometric model evaluates total use by multiplying the amount of electricity used by individual customer by the number of customers. Growth in the number of residential customers--roughly equal to the growth in the number of households--is specified as an external factor. Electricity consumption per customer is split into two parts: those for which other fuels cannot substitute (lights, refrigerators, freezers, air conditioners) and those for which other fuels can be substituted. Noncompetitive consumption is estimated as a function of electricity price, per capita income, and two demographic variables.* Competitive uses (space heating, water heating, cooking) are specified as functions of the ratio of electricity price to gas price, per capita income, and three demographic variables. Total electricity use per residential customer is then the sum of noncompetitive electricity use plus the sum of electric equipment market-shares times the assumed annual electricity use for the competitive uses.

TVA uses a great deal of detailed data in constructing their models: cross-section data for their 160 distributors from the 1970 Censuses Population and Housing and their own records; plus annual data from 1950 through 1974 on average residential electricity sales and fuel prices in the TVA area. Unfortunately, lack of complete cross-section data for the full period causes problems. In particular, models for the competitive functions are estimated with 1970 data and the noncompetitive model is estimated with annual time-series (1950-74) data. Combining these two models may introduce errors into the ensuing projections.

The way in which the noncompetitive model is defined also causes interpretation problems. It picks up changes in usage rates and in usage and equipment saturation for the competitive functions.

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*TVA's use of the term "noncompetitive" is unfortunate. This component of their econometric model includes changes in usage of competitive equipment as well as changes and usage of noncompetitive functions.

TVA estimates equipment market-shares using 1970 cross-section data. Dynamics are artificially introduced into the equations by applying the lag found in the equation dependent variable (0.678), implying that 32.2 percent of the long-run response is achieved in the first year after a change in an independent variable. Such rapid change in equipment ownership is unlikely given the long lifetimes of residential equipment (7-15 years).

Finally, the model uses assumed annual electricity estimates for the three competitive functions: 1,350 kWh for ranges, 10,000 kWh for space heating, and 5,000 kWh for water heating. These usage ranges are functions of electricity prices, incomes, and equipment efficiencies. This variation is only implied in the equations for noncompetitive uses.

The second method used by TVA, called the appliance method, estimates residential electricity use in more detail, but the estimate is also more judgmental. Household ownership of different energy-using systems (space heating, room air conditioners, freezers, small appliances, etc.) are projected. These ownership figures are then multiplied by the estimated values of annual use for each piece of equipment. The sum of these products (number of households x market-share x average kWh/yr) is the projection. This approach allows the explicit incorporation of conservation measures (such as the appliance efficiency program mandated by the Federal Energy Policy and Conservation Act). It depends heavily, however, on user judgment. Unlike the econometric approach, there is no explicit technique for evaluating the effects of changing fuel prices and incomes on ownership, efficiency, and use of household appliances and equipment.

The third method used by TVA to estimate future residential electricity use is the trend method. This involves an examination of historical data on electricity use and the assumption that historical trends will continue into the future. This method has little to recommend it except its simplicity.

As an additional check on the forecast, TVA computed two raw trends to calendar 1986, both starting in 1965 with one ending in 1973 and the other ending in 1974. These trends yielded a demand of 80 billion kWh and 60 billion kWh, respectively. The trend covering the period 1965-74 gives much lower results because it includes the effects of a recession year.

Although the residential forecast considered activities through fiscal year 1991, some methodologies projected demand only through calendar 1986. The results of the various methodologies in calendar 1986 are shown in the table below.

Results of Various Methodologies of Forecasting Residential Demand

Methodology	CY 1986 demand (billions kWh)	Average annual growth rate (1976-86)	CY 1990 demand (billions kWh)	Average annual growth rate (1976-86)
Appliance Method	54.0	4.9	(a)	(a)
Trend Method	54.9	5.0	64.7	4.8
Econometric Model	53.1	4.9	63.3	4.6

a/TVA did not use this method to forecast demand through CY 1990.

The various methods give different weights to various factors. In the end, based on its own judgment, TVA decided to use a forecast of 63.9 billion kWh for calendar 1990. This figure is very close to the averages of the trend-judgment method and the econometric model--the two methodologies that forecast demand for the entire 15-year period. Since the results of those methods were so similar, TVA believed the figure to be a reasonable one. The 4.7 percent average annual growth rate forecast for the period 1976-90 is lower than the actual 6.3 percent growth rate between 1965-75.

Included in the above forecast are the effects TVA expects from conservation and substitution in the residential sector. TVA's projection of the effects of these factors was based on a detailed analysis of the period to calendar 1986 and an assumption that the percentage relationship of these factors to the total forecast would remain constant through fiscal 1991.

Distributor-served commercial and industrial

TVA's distributor-served commercial and industrial sector has approximately 250,000 customers who used 31.3 billion kWh in calendar 1976, about 27 percent of the area's electrical requirements. Four methods were used in preparing forecasts for this sector.

In the first, TVA employed a "trend extrapolation tempered with information and judgment," dividing commercial and industrial customers into three size-of-load categories: 0-1,000 kilowatts, 1,000-5,000 kilowatts, and over 5,000 kilowatts. These categories were further split into seven groups (the five largest metropolitan areas, all cooperative systems, and all municipal systems). The number of customers was multiplied by the average usage to check the sales projection for each size-of-load category in each of the seven groups. For the two categories below 5,000 kW, TVA projected sales, average usage, and number of customers after adjusting the data for weather and seasonal variations. For loads of over 5,000 kW, peaks and total energy requirements were projected using historic trends with consideration of plant expansion, expected load additions, and inquiries for power. The projected 1990 electricity requirement for this sector was 79.1 billion kWh--an average annual growth rate of 6.9 percent.

TVA also uses a "crude linkage method" to forecast commercial and industrial demand. With this method, TVA predicts usage based on (1) the relationship of traditional growth rates of the regional economy to the national economy and on (2) the relationship of sales to distributor-served commercial and industrial customers to the regional economy. TVA estimated the growth rate of the regional economy at 1.5 times that of the national economy, the equivalent ratio of the Tennessee gross State product to the Gross National Product (GNP) in a series of 3-year periods between 1957-74. Distributor-served commercial and industrial sales have grown 1.6 times as fast as the Tennessee gross State product during the same period. (TVA used 1.3 as a factor rather than the 1.6 in computing its forecast.) On this conservative basis, it projected sales to be 1.95 (1.5 x 1.3) times the growth of the national economy. Using this method, TVA then predicted a growth rate of 8.2 percent (4.2 GNP x 1.95) through 1980 and 6.4 percent (3.3 GNP x 1.95) for the period 1980-86. The "crude linkage method" forecast a 1986 demand for the distributor-served commercial and industrial sector of 61.8 billion kWh--an average annual growth rate of 7 percent. *

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*While the official forecast concerned activity through fiscal 1991, this method was used to project demand only through calendar 1986.

TVA also uses an econometric model of aggregate electricity sales to forecast demand for this sector. It uses a single equation for each of three size-of-load categories: 0-1,000 KW, 1,000-5,000 KW, and over 5,000 KW, which makes consumption dependent on industrial output and the price of electricity. This method resulted in a 1986 forecasted demand of 57.2 billion kWh--an average annual growth rate of 6.2 percent. *

A fourth forecasting method for the distributor-served commercial and industrial sector uses an improved econometric model with the sector's electricity sales separated according to the Standard Industrial Classification code (SIC code). In this model, customers with a demand of over 100,000 kWh per month are classified by SIC codes into 16 manufacturing industries and 6 nonmanufacturing industries. Electricity sales are dependent upon economic activity represented by employment vels, conservation due to rising electricity prices, and ostitution gains resulting from higher natural gas prices. Customers with demand of less than 100,000 kWh per month were left unclassified. This group's demand represents approximately one-third of the total demand in the distributor-served commercial and industrial sector. By assuming demand in the unclassified group will grow at about the same rate as the classified sector, TVA projects a demand of 83.5 billion kWh for calendar 1990--an average annual growth rate of 7.3 percent.

Again, TVA checked the precision of their forecasts by computing two raw trends through 1986: one ending in 1973 and the other ending in 1974. The trends give a calendar 1986 usage of 80 billion kWh and 64.6 billion kWh, respectively. The results of the various methods of forecasting distributor-served demand are summarized on the following page.

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*The econometric methodology projected demand only through calendar 1986, although the official forecast encompassed fiscal 1991.

Results of Various Forecasting Methods
Distributor-served Commercial and Industrial Demand

Methodology	CY 1986 demand (billions kWh)	Average Annual Growth Rate (1976-86)	CY 1990 demand (billions kWh)	Average annual growth rate (1976-90)
Trend judgment method	61.3	7.0	79.1	6.9
Crude linkage method	61.8	7.0	(a)	(a)
Aggregate econometric model	57.2	6.2	(a)	(a)
SIC econometric model	62.8	7.2	83.5	7.3

a/TVA did not use this method to forecast demand through CY 1990.

TVA used a forecast of 79.8 billion kWh of demand in 1990 for the distributor-served commercial and industrial sector, a figure between the trend-judgment method and the SIC econometric model. Because these are the only two methodologies which go through the entire forecast period, TVA believes their figures are valid. The 79.8 billion kWh figure represents an average annual growth rate of 7.3 percent between 1976-90, 1 percent higher than the 6.3 percent average annual growth rate that occurred between 1965 and 1975.

In the distributor-served commercial and industrial sector, TVA estimates that the effect of higher real electric prices will result in a savings of 10.5 billion kWh in 1986. An estimated 4.1 billion kWh savings is projected through 1975; the remaining 6.4 billion kWh is a lagged effect of actual and projected price increases through 1986.

TVA included additional savings in this sector of .8 billion kWh under "other conservation." TVA believes the Energy Conservation and Production Act's encouragement of insulation for commercial buildings will result in future price increases and energy savings. The proposed National Energy Act would also reduce use by allowing tax credits for conservation measures in commercial buildings. However, it would encourage increased electrical use by offering incentives to commercial firms to shift from oil and natural gas, and TVA believes this fuel exchange would offset any reduction in use caused by the conservation measures. The 1986 forecast of 11.3 billion kWh in conservation savings (i.e., a reduction of 10.5 billion kWh caused by price increases plus "other" savings of .8 billion kWh) represents nearly 18 percent of the total use forecast for this sector.

The move from oil and gas to electricity among distributor-served commercial and industrial users is caused by (1) the desire for an assured energy supply, (2) environmental regulations, (3) lower operating costs, and (4) the natural gas shortage. TVA expects electricity to increasingly replace natural gas in this sector--especially in the production of process steam, for space heating, cooking, and for paint and other types of drying. TVA expects substitution in this sector to increase demand by 6.1 billion kWh in 1986--almost 10 percent of the demand forecast for this group.

Use of pollution control devices in this sector is expected to increase demand by an additional 1.2 billion kWh in 1986. This represents about 2 percent of this sector's total 1986 use.

TVA does not have adequate information about the businesses that make up the distributor-served commercial and industrial sector. This sector accounts for almost 27 percent of the region's total present requirements, a percentage which is expected to increase to almost 33 percent by 1990.

Approximately two-thirds of all demands in this sector are by customers classified by the SIC code--those that use over 100,000 kWh per month. Assuming the 1990 demand forecast is correct and assuming that the unclassified customers will still account for the remaining one-third, their demand will be over 26 billion kWh. This is greater than the total of the direct-served industrial load in 1976, and is expected to total more than 10 percent of area requirements in 1990.

Direct-served industry

TVA directly serves about 50 industrial customers who have large or unusual power requirements. In 1976, this sector accounted for approximately 20 percent of the total area requirements, or about 23.5 billion kWh. TVA uses two methods to forecast this demand.

Using the "trend survey" method, TVA contacted the firms and considered contract negotiations, contract demands, peak loads as a percent of contract demands, and the recession-influenced behavior of various types of loads. TVA also studied the past growth and outlook for various manufacturing categories of industry when determining a growth allowance. Based on its analysis using the trend-survey method, TVA predicts a calendar 1990 demand of 43 billion kWh among the direct-served industries--an average annual growth rate of 4.4 percent.

TVA also uses an econometric model to forecast demand for this sector. Loads in this category are tested for responsiveness to electricity prices, economic activity, and natural gas costs to check for the appeal of fuel substitution. The model produces a forecast for four types of industry (aluminum, chemicals--excluding phosphorous--,ferroalloys, and paper) which account for approximately 80 percent of the direct-served industrial load. The remaining load input, concerning phosphorous and miscellaneous manufacturing, is based on historical trends. The demand for 1976 and the forecast for 1990 are shown in the table below.

Direct-Served Industry Forecast
Using Econometric Model

Industry Type	CY 1976 Actual Demand	CY 1990 Projected Demand	Average annual growth rate
	(billions kWh)		
Aluminum	10.8	19.8	4.4
Chemicals (excluding phosphorous)	6.1	9.3	3.1
Ferroalloys	2.1	2.9	2.3
Paper	1.3	1.8	2.4
Phosphorous (note a)	2.2	4.0	4.4
Miscellaneous (note a)	1.0	1.5	2.9
Total	23.5	39.3	3.7

a/Input based on trend analysis.

The econometric model yielded a lower forecast than the trend-survey approach, primarily because historical trends indicated that the TVA area's share of U.S. production will decrease. TVA officials said the model does not predict the extent to which industries may relocate to the Valley.

TVA decided to use the results of the trend-survey method to forecast the direct-served industrial demand. TVA predicts that this sector's needs will grow at an average annual rate of 4.4 percent between 1976 and 1990 and that 43 billion kWh of electricity will be used by this sector in calendar 1990.

This percentage is somewhat higher than the historical growth level of 3.3 percent experienced between fiscal 1965-75, but a severe recession in 1975 greatly depressed the direct-served load that year. The growth rate was 4.4 percent between 1965-74. This makes the projected growth rate of 4.4 percent between 1976-90 appear reasonable.

TVA did not incorporate effects of conservation, substitution, or pollution control in its forecast of this sector. It believes that there is very little conservation potential among direct-served industries because most of their use has a direct effect on production. According to TVA officials, energy-intensive processes such as electric drive, electrolytic cell applications, and pollution control typically account for at least 95 percent of industry's electricity use. A 2- or 3-percent reduction in electricity by direct-served industry might be possible through reduced heating, lighting, air conditioning, etc. TVA assumed that anti-pollution activities will amount to about 7-percent of this group's demand by 1986. Thus, they assumed that any conservation by this group will be offset by pollution control activities.

Among direct-served industries, while TVA believes there is a strong potential for fuel shifts to electricity it believes most shifts will be from gas to oil. Therefore, no allowance was made for fuel substitution by this group.

TVA does not have adequate support for its forecast of electrical usage among direct-served industrial customers. As mentioned, four types of industry account for about 80 percent of the total demand. In 1976, TVA did an analysis of the aluminum industry in an attempt to determine what share of the industry would be located in the Valley by 1986. We were unable to verify that any detailed analysis has been performed recently for the remaining portion of the direct-served industrial load. While TVA has attempted to develop an econometric model for this sector, the model results have been very unreliable.

Federal demand

TVA directly serves Federal agencies in the Valley that have an annual demand of 5,000 kWh or more. In calendar 1976, the Federal load totaled about 22 billion kWh, about 19 percent of the region's total requirements. DOE loads account for over 90 percent of Federal demands. Two DOE gaseous diffusion plants, in Oak Ridge, Tennessee, and Paducah, Kentucky, use over 10 percent of TVA's total annual generation for uranium enrichment.

Critique of TVA models

Both models employed by TVA have obvious limitations; there is a lack of appropriate data and there are errors of measurement in the data available. Such constraints make modeling an art rather than a science and demand the highest degree of skill and sophistication.

In both models TVA substituted data for Tennessee for data from the power service area; an implicit assumption that the industrial structures were the same in the power service area as they are in the State. This may be an accurate assumption, but one may be skeptical because of the heavy specialized industrial concentration in Northern Alabama.

Data limitations may also have prompted the use of employment rather than more appropriate output variables in the econometric models, and may be the reason the analysis was limited to two-digit industries. It would seem desirable to have information on industries below the two-digit level for those are of particular importance in the TVA region, such as primary metals, chemicals, and wood products. At the technical level, the TVA econometric models have problems common to all recent energy demand models, an apparent recent structural shift towards a more energy-efficient economy. Data for only a few years is available which reflect this shift, but econometric models must be estimated with historical data. The significance of this point for future projections is readily seen when the impact of cross-price elasticity is considered. To quote TVA:

> "Since the prices of coal, oil, and natural gas were not found to be important indicators for electricity use in the historical period, the econometric model cannot capture the importance of interfuel substitution without judgmental input."

During most of historical period, the values of these variables were collinear but this is not expected to be the case in the future.

Perhaps the most important criticism of the TVA econometric models is that some of the equations may be misspecified. As noted earlier, for many industries, poor results were obtained (that is, low R). It may be that the TVA models are too narrowly defined in terms of standard economic theory and that important "noneconomic" variables have been left out of the equations. Principal candidates for investigation would be the impact on demand of the so-called "engineering" variables, similar to those employed in the Oak Ridge National Laboratory (ORNL) model of residential energy demand.

ALTERNATIVE ENERGY SUPPLY AND DEMAND PROJECTIONS FOR THE TVA REGION

TVA uses various methodologies in forecasting energy demands which result in a single, official forecast for the region. This section provides details of our two alternative projections and compares them with TVA's. They are first discussed in terms of residential demand and commercial/industrial demand, and then in terms of the region's total demand.*

RESIDENTIAL DEMAND

This section evaluates alternative methodologies for preparing demand projections for the residential sector and presents several projections. The TVA projections presented are based on TVA's July 1977 load forecast. 1/ Alternative or "GAO" projections are based on the residential energy use model developed by ORNL. 2/ These alternative projections evaluate the energy and direct econmic effects of adopting various conservation programs and the effect of making the different assumptions concerning future prices of electricity discussed in chapter 5.

The ORNL residential energy use model can be considered a combination of the econometric and appliance methods used by TVA (see app. I). The ORNL model contains the behavioral features of the econometric approach (sensitivity to economic variables) and the engineering detail of the appliance method (8 end uses x 4 fuels x 3 housing types = 96 fuel use components). Because of the model's detailed structure and explicit sensitivity to the key determinants of residential energy use, it can endogenously handle a variety of inputs: fuel price changes, appliance efficiency standards, retrofit programs, changes in household formation and housing choices, and introduction of new residential technologies such as solar heating.

The model for the TVA region is based on the ORNL model for the East South Central division; including the States of Kentucky, Tennessee, Alabama, and Mississippi. Because TVA's electricity prices have historically been quite low, ownership of electric equipment is higher in the TVA region than in this division. Therefore, the inputs to the model have been adjusted to reflect more accurately the TVA area. The

*Federal demand is the same for all three projections.

goal was to calibrate the ORNL model so that it correctly predicted residential electricity use for the initial year of the simulation, 1970 (26.6 billion kWh). The results of this simulation were:

	TVA	ORNL
1970	26.6	26.5
1971	27.9	27.7
1972	29.8	29.5
1973	32.1	31.8
1974	32.3	33.3
1975	33.2	33.2
1976	33.6	33.6

The ORNL model is plagued by the same data problems that cause difficulties with the TVA model. In particular, detailed engineering and economic data does not exist to fully support the level of detail (96 components) in the ORNL model. Also, the fuel price and income elasticities in the ORNL model are based on national econometric analyses and may not reflect the regional characteristics of the TVA area.

Baseline projections

Table II-1 and figure II-1 show the TVA projections and our high and low projections through the year 2000 for the region's residential demand. Our baseline projections considered the same inputs on population, households, housing choices, fuel prices,* and incomes that were used in the TVA forecast.

The TVA forecast is based on all three methodologies discussed in app. I. Staff in the TVA Analysis Branch compare results of the three forecasts and then adjust the forecasts to include some substitution of electricity for natural gas because of assumed gas shortages and to include nonprice conservation (the Federal appliance efficiency program and the TVA home insulation program). The TVA forecast shows residential electricity use growing from 33.2 billion kWh in 1975 to 63.9 billion kWh in 1990, with an average annual growth rate of 4.7 percent.

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*The prices of gas we use are higher than those provided by TVA. We raised gas prices to reduce growth in residential use of gas during the late 1970s and 1980s.

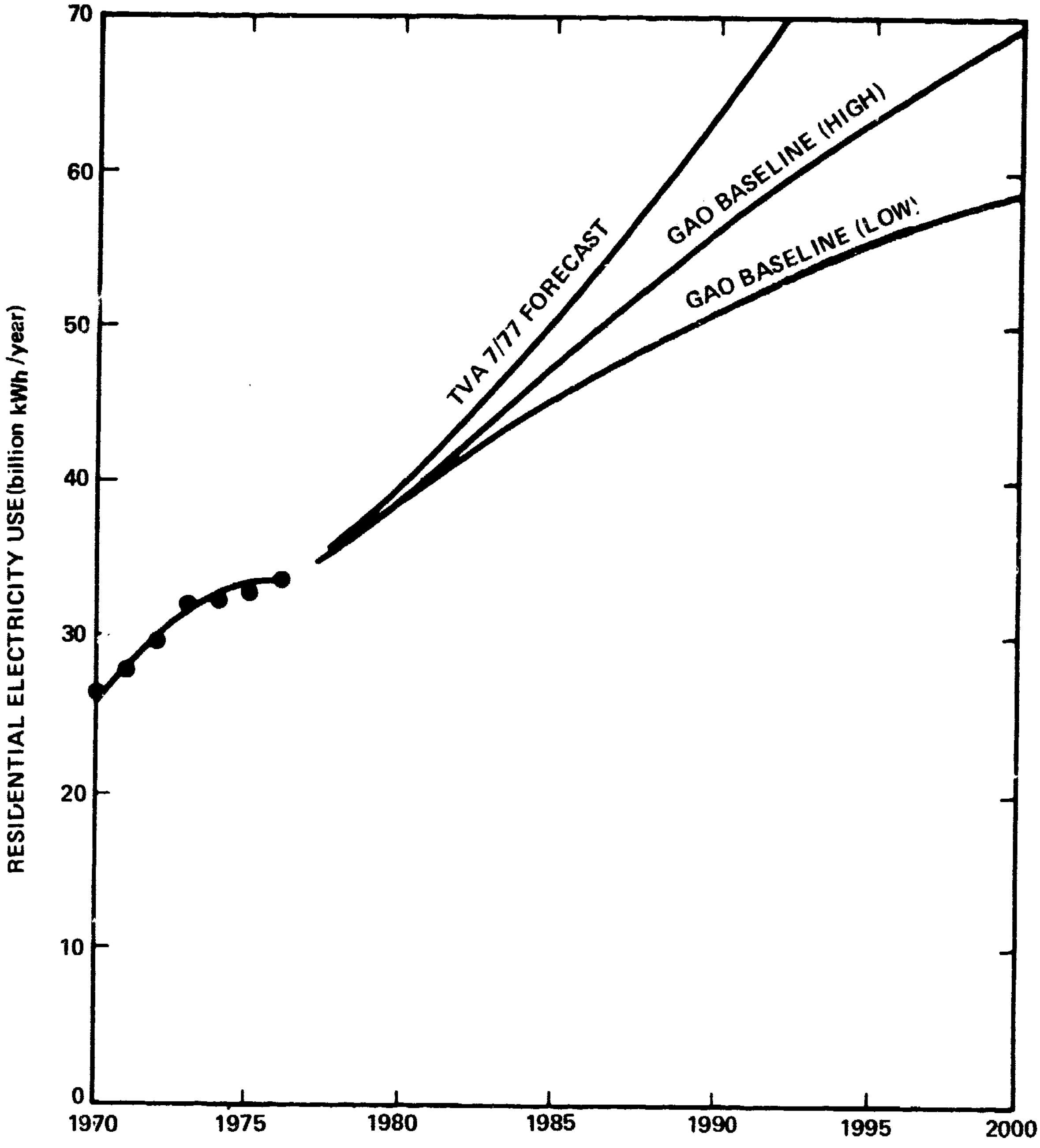

FIGURE II-1 PROJECTIONS OF RESIDENTIAL ELECTRICITY USE WITH AND WITHOUT GOVERNMENT CONSERVATION PROGRAMS: RISING REAL ELECTRICITY PRICES.

Our high projection obtained with the ORNL model assumes that no Government conservation programs are implemented. However, because of electricity price increases in the TVA region through 1975, households voluntarily reduce the intensity with which they use equipment, select more efficient new equipment, and retrofit (weatherize) existing household units.

TABLE II-1

Residential Electricity Use Projections For the TVA Region

Year	TVA forecast	Our high projection	Our low projection
	(billion kWh)		
1975	33.2	33.2	33.2
1980	40.1	39.6	39.0
1985	51.4	47.8	45.7
1990	63.9	56.3	51.6
1992	70.2	59.0	53.1
2000	106.1	70.0	59.0

Based on estimates from "Annual Housing Survey: 1975" * it is assumed that 370 thousand single-family units and 20 thousand multifamily units will be retrofit by 1980. 3/ This represents 23 percent of the 1975 stock of occupied single-family units and 7 percent of the multifamily units. Also, the efficiencies of new structures and equipment improve over time because of the recent increases in electricity price. Thus, even though the high baseline projection does not explicitly include the two Government programs in the TVA projection, it does include estimates of voluntary responses to fuel price changes.

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*This data shows that 17 percent of the occupied single-family homes in the East South Central division had some retrofit action taken (additions of attic insulation, wall insulation, storm windows, storm doors, caulking, and weatherstripping) during 1975.

Our high baseline shows a growth in residential electricity use between 1976 and 1990 of 3.8 percent a year (compared with TVA's growth of 4.7 percent a year). Between 1990 and 2000, the average growth in our high projection is much lower (2.2 percent a year) than in the earlier period because household growth is much lower during the later period. Per household electricity use grows from about 16,000 kWh per year in 1976 to almost 20,000 kWh/yr in 1990 and 22,000 kWh/yr in 2000. Our 1990 high projection is 12-percent lower than the TVA projection and 34-percent lower in the year 2000.

To a large extent, estimates of future residential electricity demands in the TVA region depend on assumptions made concerning future electricity prices. Estimates from TVA suggest that the real price of electricity will remain essentially constant between 1975 and 1990. This assumption of constant real electricity prices which we used in our high projection assumes the use of larger nuclear powerplants with very low operating costs.

Because TVA's assumptions on future electricity prices is different from the conventional assumption of rising electricity prices, our low baseline projection assumed that the price of electricity in the TVA region would rise from its 1976 value (2.1 cents/kWh in terms of 1975 dollars) at an average annual rate of 1.0 percent to show the sensitivity of residential electricity demands to the price of electricity. All other assumptions for this low projection were the same as those in our high projection.

Our low projection shows a growth in residential electricity use between 1976 and 2000 of 2.3 percent a year compared with 3.1 percent in the original baseline. In 1990, electricity use is 51.6 billion kWh, 9 percent less than in the high projection and 59.0 billion kWh in 2000, or about 16 percent. Clearly, assumptions on electricity price have important consequences with respect to future electricity demand.

The direct economic impact of these higher electricity prices in the region's households is that cumulative expenditures through 1990 are higher by $670 million ($240 per household) because electricity prices are assumed to increase. This increase has several components. High fuel prices (relative to the original baseline) cause consumers to voluntarily reduce their consumption of electricity. This occurs both by changes in systems ownership (selection of more efficient equipment and structures, and some switching from electricity to other fuels) and by changes in the intensity with which equipment is used (e.g., shorter showers and closer attention to thermostat settings). These changes soften the economic impacts of higher fuel prices.

The following reasons help explain the difference between TVA's and our projections.

--TVA shows a use of electricity for "other" purposes of 335 kWh/customer in 1976 and 1,750 kWh/customer in 1986. Apparently, this growth (18 percent a year) is based on trends in ownership of small household appliances and the assumed introduction of electric vehicles in the TVA area. Had this use not grown, our high and TVA's projections would be almost identical. "Other" uses of electricity grow at about 5 percent a year in our high projection.

--TVA uses residential customers as the basis for its projections. Households are used in the ORNL model. Because the number of customers is projected to grow slightly faster than the number of households, this contributes to a higher TVA projection.

--TVA projects a faster growth in electric water heating market-share. Also, TVA assumes that new refrigerators and freezers purchased between 1976 and 1986 will use more electricity than the average units in use in 1976. This adjustment accounts for the fact that new refrigerators use more energy than the average units in use because new units are larger and more likely to be frost-free. The ORNL model does not account for these trends in refrigerator purchase; it shows a decline in annual unit electricity use because of recent electricity price increases.

--The ORNL model shows residential use of gas increasing slightly from 1976 through 1982 (by 6 percent). This may be unrealistic given present constraints on gas supply. This increase in gas use occurs in the model because it is a classical energy demand model (it assumes that fuels are always available at the given price).

--The national own-price elasticity of demand for electricity in the ORNL model (-1.0) is higher than the comparable elasticity derived by the Analysis Branch for the TVA region (-0.6). An ongoing project at ORNL to develop econometric models of electricity demand for each Census division shows an own-price elasticity for the East South Central division of

-0.9. A recent ORNL analysis of residential demand for electricity in the TVA region shows an own-price elasticity of -0.7. 4/ There is obvious uncertainty regarding the price elasticity of demand. Our analysis in our demand projections has used the -0.6 and -0.1 as probable boundaries for such elasticities in the TVA region.

Given the different methodologies employed and the lack of detailed data on electricity uses, it is gratifying to see such close agreement between projections in 1990. The only troublesome question about the projections concerns differences in assumptions (both explicit and implicit) on conservation programs. The TVA projection includes Federal and TVA programs, whereas our baseline projection does not. The TVA forecast includes the effects of the Federal appliance efficiency program (saves 2.5 billion kWh in 1986) and their program to add attic insulation to 464,000 electrically heated homes (saves 1 billion kWh in 1986). Our baseline projection assumes that 200,000 electrically heated homes are voluntarily retrofit by 1980. Also, part of the effect of the appliance program is captured in our model by the voluntary improvements in appliance efficiency due to recent electricity price increases.

Potential impacts of conservation programs in our high and low projections were handled separately in chapter 5 to better identify the associated costs and energy savings.

COMMERCIAL, INDUSTRIAL, AND FEDERAL DEMAND

Federal purchases

Federal purchases (almost entirely for uranium enrichment) comprise approximately 20 percent of TVA's total generation and, therefore, merit special attention. The demand for electricity to enrich uranium is determined by two factors (1) electricity demand in this case is a derived demand and is a function of the demand for the final product. The two main sources of demand for enriched uranium are (a) nuclear fuel electric power stations and (b) weapons production and (2) the current production technology used to produce enriched uranium is the highly energy intensive gaseous diffusion method.

Significant shifts in either the demand for enriched uranium or enrichment production methods could have drastic effects on TVA's future generation requirements. For example, a national policy to de-emphasize nuclear power would slow if not stop the growth in demand for nuclear fuel while new enrichment technologies, such as gas centrifuge and laser, are reported to require only 10 percent of the energy needed by the gaseous diffusion process.

In forecasting future energy requirements for uranium enrichment, TVA is largely dependent on DOE. DOE has contracted for 4,485 MW in 1985, and both TVA and GAO have used this figure in its forecast. Beyond 1985, however, the nuclear picture becomes clouded by uncertainties in the demand for enriched uranium as well as in the technique for enriching uranium. Since this sector represents such a large portion of TVA's total demand load, it will become increasingly important to require more detailed long-run information from DOE, and perhaps to construct some forecasts independent of contracts with reserve capacity, but do not guarantee its use.

Commercial and industrial demand

In the case of residential demand, it was possible to prepare and evaluate projections produced by two modeling systems of relatively equal levels of sophistication. Unfortunately, a model similar to the ORNL residential model does not exist for the combined commercial/industrial sector and it is well beyond the scope of this report to develop such a model. Instead, a simple projection model has been estimated and used to develop our baseline projections of commercial and industrial demand in the region. This model may be stated as follows:

$$E(t) = f(P(t), GRP(t), S)$$

where E(t) is the commercial and industrial consumption of electricity in the TVA region in a given year, P(t) is the real price of electricity sold to commercial and industrial consumers in a given year, GRP(t) is real gross regional product in year t*, and S is a shift variable taking the value of one for all years after 1970 (the year the unit price of electricity started to increase in the TVA region) but is zero for earlier years.

This model has been estimated with data covering the period 1952-76. An excellent fit was obtained (R = .99)

*Due to a lack of regional data, it was necessary to use Tennessee gross State product, a practice also followed by TVA.

(statistical significance at the .05 level or better). The model was calibrated to predict the final year in the sample (1976) and demand was projected for the years 1985, 1992, and 2000. Using the TVA assumptions, the model projected a 1985 demand of 86.0 billion kWh which is slightly higher than the TVA projections of 85.8.

Baseline projections of commercial and industrial demand

Two of our projections have been prepared and are presented in Table II-2. For our high projection, it was assumed as TVA did, that economic growth would continue at a rapid rate (5.8 percent a year) through the year 2000. This projection also considers a constant real price of electricity through the year 2000 the same as TVA's. In addition, it has been assumed that the energy intensity of production declines after 1976 at a rate of 1.0 percent per year. This assumption amounts to decreasing the coefficient of GRP at a compound rate of 1.0 percent a year over the period 1976-2000.

This last assumption warrants further discussion. While on the surface it may appear arbitrary, in actuality the ratio of energy use to total output has been falling in excess of 1.0 percent per year since at least 1960. 5/ To ignore an increase in energy efficiency that began when energy prices were relatively low during a period when energy prices are expected to be relatively high would seem to be unrealistic to say the least.

Furthermore, to leave the coefficient of GRP at its estimated level for our projections would result in projections that reflect the average energy intensity of production during the 1952-76 period. Such a projection is a good baseline or business-as-usual projection as presented in the TVA projection.

Our low projection differs from our high projection by assuming a lower rate of growth and a 1 percent increase in the real price of electricity. Specifically, gross regional product increases at a 5.8 percent a year rate through 1985, slows to 4.0 percent a year during the 1986-92 period and then drops to a roughly equivalent concensus national rate of 2.7 percent a year thereafter. (See table II-3.)

As shown in table II-2, in the year 2000, our high projection for commercial industrial demand is 177.8 billion kWh, or about 10-percent less than TVA's 197.2 billion kWh. Our low growth projection yielded only 107.2 billion kWh or about 46-percent less than TVA's, predominantly due to the decreasing growth rate.

APPENDIX II

TABLE II-2

Forecasts of Demand For Electricity in the Commercial and Industrial Sector of the TVA Region

Year	Federal Government	Industrial and commercial sector			Total demand industrial and commercial plus Federal Government		
		TVA (note a)	High growth	Low growth	TVA (note a)	High growth	Low growth
	--------	--------	--------	(billions of kWh)	--------	--------	--------
1975	20.1	50.1	50.1	50.1	72.1	72.1	72.1
1985	40.5	85.8	86.0	77.3	126.3	126.5	117.8
1992	40.5	125.2	120.5	93.4	165.7	161.0	133.9
2000	40.5	169.1	177.8	107.2	209.9	218.3	148.0

a/"Industrial and Commercial Energy Consumption," Source book of TVA, Models and Projection Routines 1977.

TABLE II-3

Alternative Values of Predetermined Variables
(Rate of Growth in a Percent a Year)

	TVA	CONAES B (note a)	IEA (note b)	EPP/TF (note c)	Our high	Our low
			Price of electricity			
1985	d/0.0	2.0	2.0	3.85	0.0	1.0
1992	d/0.0	2.0	2.0	N/A	0.0	1.0
2000	N/A	2.0	2.0	N/A	0.0	1.0
			Gross regional or national product			
1985	e/5.8	f/2.7	f/3.85	f/4.06	e/5.8	e/5.8
1992	N/A	2.0	2.66	2.73	5.8	4.0
2000	N/A	2.0	2.66	2.73	5.8	2.7

a/Committee on Nuclear and Alternative Energy Systems, a study by the NAS/NRC for the Energy Research and Development Administration, December 1976.

b/"Economic and Environmental Implications of a U.S. Nuclear Moratorium," 1985-2010, Charles E. Whittle, et al., ORAU/IEA 76-4, September 1976.

c/Energy Policy Project of the Ford Foundation, "A Time to Choose," 1974.

d/Not applicable.

e/Gross regional product.

f/Gross national product.

COMPOSITE DEMAND FORECASTS

Table II-4 presents TVA's and our two alternative demand projections for the total TVA system. Our high and low projections are a composite of the highs and lows in tables II-1 and II-2. It should be recalled that the primary differences in our projections and TVA's are

--the high residential price elasticity (-1.0) compared with TVA's (-0.6),

--the 1 percent a year decrease in energy intensity in the commercial/industrial sector,

--a 1 percent increase in the real price of electricity under our low projection, and

--a growth rate of gross regional product from 5.8 percent through 1985 declining to 2.7 percent in the year 2000 under our low projection.

The implicit compound growth rates for the total demand projections are shown in table II-5.

TABLE II-4

Projections of Demand for the TVA Power Service Area

YEAR	TVA	Our high	Our low
	------------(billions kWh)------------		
1975	105.3	105.3	105.3
1985	177.7	174.3	163.5
1992	235.9	220.0	187.0
2000	316.0	288.3	207.0

TABLE II-5

Implicit Compound Growth Rates
For Composite Demand Projections 1975-2000

Projection	Percent: Without Federal purchases	Percent: With Federal purchases
TVA	4.8	4.5
Our high	4.3	4.0
Our low	2.7	2.7

IMPLICATIONS FOR PEAK DEMAND

In the 1977 TVA Load Forecast, peak demand was projected to grow at about the same rate as total demand. The implications of following this procedure for our projections are compared with TVA's forecast in table II-6. As can be seen, the projected peak demand in the year 2000 under our low projection is 37,100 MW or about 40 percent lower than TVA's. Our high forecast is 51,900 MW, or about 17 percent lower than TVA's.

APPENDIX II

TABLE II-6

Projected Peak Demands for the
TVA Region

Year	TVA	Our high	Our low
	(megawatts)		
1975	18,600	18,600	18,600
1985	34,300	31,400	29,400
1992	46,700	39,600	33,600
2000	62,600	51,900	37,100

FOOTNOTES

1/Division of Power Utilization, "The Proposed July 1977 Load Forecast," Tennessee Valley Authority, 1977.

2/E. Hirst, et al., "An Improved Engineering-Economic Model of Residential Energy Use," ORNL/CON-8, April 1977 and E. Hirst and J. Carney, "Residential Energy Use to the Year 2000: Conservation and Economics," ORNL/CON-13, September 1977.

3/Bureau of the Census, "Annual Housing Survey: 1975," unpublished data tabulated for the Federal Energy Administration, U.S. Department of Commerce and L. C. Maxwell, "An Econometric Model of Distributor Residential, Commercial, and Industrial Electrical Energy Sales," Tennessee Valley Authority, June 1976. L. C. Maxwell, "The Residential Demand for Electricity in the TVA Area," Tennessee Valley Authority, May 1976.

4/G. S. Gill, et al., "The Growth of Electric Heating in the TVA Area," ORNL/CON-12, July 1977.

5/Personal Communication from John W. Morgan, Oak Ridge Operations, Department of Energy, October 1977.

TENNESSEE VALLEY AUTHORITY
KNOXVILLE, TENNESSEE 37902

OFFICE OF THE BOARD OF DIRECTORS

September 29, 1978

Mr. Monte Canfield, Director
General Accounting Office
Washington, D.C. 20548

Dear Mr. Canfield:

In the meeting in your office on September 12 we discussed five specific areas of concern. As a followup to that meeting, Douglas McCullough, Coy Belew, and W. M. Williamson met with TVA representatives in Chattanooga on September 19. In this meeting the five areas identified were resolved to the satisfaction of all. In that meeting a number of suggestions were made by TVA for changes of some words and some of the numbers in the report and other suggestions for clarification. GAO was also given comments on appendices 1 and 2.

As we discussed in your office, we recognize that this report has been some time in the writing and that it inherently reflects the situation that existed about 1977. Almost every item you criticized from the load forecasting to absence of technological innovation in coal generation is now obsolete. I hope that you will take the opportunity in the report to recognize that we are now very much involved in carrying out programs which you recommend.

TVA is now actively engaged in the implementation and consideration of many load management methods, energy conservation measures, and nontraditional generating sources. These include the use of solar energy devices, specifically those for solar water and space heating, cogeneration, expansion of the use of interruptible power contracts, radio and time clock control of water heaters, rate restructure, storage devices such as batteries, and compressed air.

We are carrying out essentially all the innovations you suggested and many others not mentioned in the report such as our electric vehicle and our fuel cell program. We are committed to a long-range goal of reducing the dependence of the TVA region on petroleum through the development, demonstration, and application of transportation more effectively using existing fuels or electricity which can be produced from more plentiful resources. It is our intent to make the electric vehicle a useful load-management tool. In our fuel cell program we are working on a concept of locating fuel cells in urban areas to produce electricity and also use the waste heat in industrial or residential applications. The fuel for these cells would be obtained from a mine-mouth coal gasification plant via a pipeline. More details on these programs were handed to your representatives at the September 19 meeting, as well as some further information on our cogeneration activities.

The last page of the report is concerned with a new mandate for TVA. It is our policy to provide leadership in the development of electricity management plans and programs, to encourage energy conservation and the most efficient production and use of energy, to maximize energy conservation and the use of renewable resources, and to involve the public in energy planning and policymaking. We are now actively moving to assume this leadership role. This can and will be done within the provisions of the TVA Act, and we see no need for Congress to revise TVA's charter.

Sincerely,

S. David Freeman
Chairman

Department of Energy
Washington, D.C. 20545

July 24, 1978

Mr. Monte Canfield, Jr., Director
Energy and Minerals Division
U. S. General Accounting Office
Washington, D. C. 20548

Dear Mr. Canfield:

We appreciate the opportunity to review and comment on the GAO draft report entitled "Electric Energy Option Hold Great Promise For The Tennessee Valley Authority."

Comments pertaining to the report and its recommendations follow.

(SEE GAO NOTE)

Also, the recommendation that the Congress revise the TVA charter to charge TVA with "leading the development of electricity management places and program" and other items does not appear appropriate since such broad charter mandates are the responsibility of the DOE. The report should tie in TVA efforts in regional planning and commercialzing new energy supplies with similar efforts by the Power Marketing Administration of the River Basin Commission, the Water Resources Council and the Presidents' new moter policy. Also, the initiative suggested in the report should be closely coordinated with DOE, EPA and other appropriate governmental bodies.

On pages 4-1 through 4-14 it is pointed out that TVA uses only one demand forecast in its planning and that two GAO forecasts of lower demands be considered by TVA in its planning. There is considerable uncertainty in forecasting demand 15 or more years into the future.

GAO NOTE: The deleted comments related to matters which were discussed in the draft report but have been revised in this final report.

APPENDIX IV

The fact that TVA uses one set of projections for planning does not mean that a range of projections is not considered. As a practical matter TVA like other utility systems has a decision to make in planning future capacity. Naturally, the most economic system will result if projections turn out to be accurate. Increased costs will result whenever demand exceeds or is less than the projection adopted. The time required for constructing a large power plant reduces the amount of flexibility a system has in holding off decisions on the addition of specific units or plants. Therefore, a system must make its best projection and revise it and its plans as necessary.

The discussion in Chapter 4 seems to be explaining the results of the affect of using uncertain numbers of forecasts which concludes in unsupported assumptions on page 4-18. Also, the flat assumption that uranium enrichment will require 40.5 bkwh through the year 2000 is arbitrary. This assumption could be sharpened up particularly as total 1985 demand is projected at 126 bkwh. Further, only a limited range of advanced generating technologies is treated.

The institutional and environmental barriers to energy growth should be explored in more depth.

Chapter 5 is also concerned with somewhat arbitrary assumptions to show the affects caused by or associated with changes in the assumptions.

The TVA assumption that nuclear plants (page 5-6) will allow it to avoid any real increase in electricity cost in 1975-1990 appears to have been based on inputs of as long ago as 1976. The assumption should be updated.

The load problem discussion in Chapter 5 ignores the option of flexing uranium enrichment demand to minimize drawdown in peaking power. This option is, in fact, now being utilized by TVA.

Sincerely,

Fred L. Hiser, Director
Division of GAO Liaison
Office of the Controller

(00855)

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