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Utility Overview Study Report – FY 1985: Regional Indicators of Potential for Electric Utility Demand-Side Management Programs

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UTILITY OVERVIEW STUDY REPORT - FY 1985: REGIONAL INDICATORS OF POTENTIAL FOR ELECTRIC UTILITY DEMAND-SIDE MANAGEMENT PROGRAMS†

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Utility Overview Study Report - FY 1985*
Regional Indicators of Potential for Electric Utility Conservation Programs

by
W. Yen-Wood, E. Kahn, M. Levine

The advent of increasing marginal costs and slower growth in the 1970's along with a proactive regulatory environment have spurred utilities to explore alternatives to traditional planning methods. Key factors that affected the industry were the failure of expected high demand growth to materialize, rapid increase in construction costs, the emergence of environmental concerns relative to generation and transmission facilities, increases in worldwide price of fossil-fuels, conservation legislation, and problems in the nuclear power industry. Both "Least-Cost Planning" and "Demand-Side Management" represent utility efforts to improve system efficiency through closer matching of electricity supply and demand. Among utilities, Least-Cost Planning is a strategic resource planning concept which compares the cost/benefit of "demand-reducing" and "capacity enhancing" options to that of constructing new power plants. Demand-side management involves development of end-use programs to influence the expected load shape. A central concern for analysts engaged in these activities is how to integrate the consumer's energy service needs with the utilities' system requirements so as to optimize "quality, reliability, and stable electricity prices". (Ref 2)

In this context, the primary objectives of the Utility Overview Study are to:

- Provide an estimate of *where* and *when* utilities are likely to be interested in promoting energy conservation as an alternative to energy exchange arrangements or construction of new plants to meet future energy demand;
- Provide a framework for relating the conclusions of LBL utility case studies on financial impacts of energy conservation to the national context.

Study Approach

Utility interest in conservation is related to a number of economic and institutional issues. (Appendix V). We focused on three factors (energy supply/demand balance and cost, ratemaking, and political/institutional environment) as indicative of the utility decision environment (See Figure 1). Both quantitative and qualitative indicators are included in the study. Quantitative indicators deal with energy and capacity requirements. Qualitative indicators include aspects of the rate-making and political/institutional environment such as rate structure, allowance for Construction Work in Progress (CWIP), and the interest of state public utility commissions in energy conservation. Evaluation of potential utility interest in energy conservation will require understanding how these measures interact with each other in a given decision-making context.

Level of Analysis

Investor-owned utilities (IOUs) in the U.S. have a 77% share of total electricity generating capacity and 76% of total sales. The database developed in this study includes 85 IOUs representing 90% of total generation by IOUs. Due to the complexity of the utility planning environment as well as data availability considerations, we have incorporated several levels of aggregation in the study in addition to utilities. Reserve capacity is analyzed primarily at the level of National

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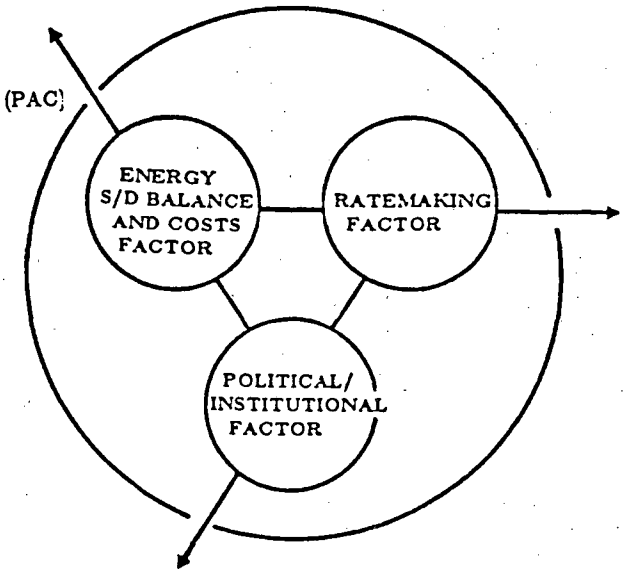
Figure 1.
Overview of Indicators

- Percent Low-Cost Capacity (PLCC)
- Years Until Expensive Power is Needed (YEARS)
- Percent Avoidable Construction (PAC)
- Capacity Surplus/Deficit (SUR/DEF, SHORT)
- Years Until New Capacity is Needed (RYN, SubRYN)



- Rate Structure (RATES)
- Residential (RES)
- Commercial (COMM)
- Industrial (IND)
- Farm (FARM)
- Availability of Construction Work in Progress (CWIP)

Regulatory Commission Sponsored Conservation Initiatives:
- Insulation (INSUL)
- Energy Audits (AUDIT)
- Solar Utilization (SOLAR)
- Load Managment (LOAD)
- Waste Heat Utilization/Cogeneration (COGEN)
- Other Measures (OTHER)
- Utilities Required to Invest in all Cost-effective Energy Conservation Prior to New Energy Resources (INVEST)
- State has Independent Assessment of Conservation Potential (ASSESS)
- Commission Offers Conservation/Load Management Incentives (INCENT)
- Demand-Options Included in Required Resource Plans (OPTION)
- State has Statutory Authority to Require Utility Investment in conservation and load management (STAT)

Electric Reliability Council (NERC) regions and DOE electric regions (approximating NERC subregions) because company-specific data for power exchanges is not readily available. Analyses of public service commissions' interest in energy conservation are at the state level.

Organization of Report and Guide to Appendices.

This summary report highlights the findings of the Overview study at the NERC Region, DOE Electric Region and State level. We have focused on six indicators to characterize the key considerations that influence utility interest in development of energy conservation programs. The detail results of the study are presented in the Appendices along with data relevant to the analyses of the indicators. We will reference appropriate portions of the Appendices in the discussion of each indicator.

Indicators included in the Appendices are organized by U.S. (Appendix I), NERC Regions (Appendix II), DOE Electric Region (subregion) (Appendix III), States (Appendix IV), and Selected Electric Utilities (Appendix V). All utility-specific indicators in the appendices are presented in order of the NERC Region and DOE Electric Regions (subregions) to which the utility belongs. To facilitate cross referencing, indexes are provided for NERC Regions, DOE Electric Regions, States, and Utilities at the beginning of each appendix.

Data Sources

To carry out our analyses, we rely primarily on data compiled and validated by the Department of Energy (DOE), the Energy Information Administration (EIA) and key industry organizations such as the North-American Electric Reliability Council (NERC), the Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners (NARUC), and the Gas Research Institute (GRI).

1. Government Sources (DOE publications are also included as References)
   - Tape of EIA -759. Monthly Power Plant Report. Provides net generation, fuel consumption, and end-of-month fuel stocks for all electric generating plants to 1983.
   - Tape of FERC -1. Annual Report of Electric Utilities, Licensees, and Others (Class A and B). Includes data on general corporate and financial information. Survey respondents are Class A or B companies. (Class A companies have annual electric operating revenues of $2.5 million or more; Class B companies have more than $1 million but less than $2.5 million)
   - EIA Form 119A data summary report prepared by the Energy Information Administration. Provides 1982 energy and peak load forecasts for an advamce 20-year period.
   - 1984, 1985 DOE staff reports based on data submitted by NERC regional councils on Form EP-411. Provides data on generating capability and reserves for a 10-year advance period. (See Ref. 11)
   - U.S. Congress, Office of Representative Claudine Schneider - Survey of Regulatory Utility Commissions" Electrical Resource Planning and Conservation Activities, 1985. Provides information on state regulations, legislation, rules orders and innovative rate treatments undertaken to promote least-cost energy strategies.
2. Industry Sources
   - NERC - 1984, 1985 annual data summary reports on electric power supply and demand. Provides annual compilation of utility data for installed supply and planned resources, current and projected peak demand and electricity requirements by NERC regions and subregions for an advance ten-year period.

- EEI, Statistical Yearbook of the Electric Utility Industry/1982, 1983. Provides data on operational and financial aspects of the electric utility industry. Includes data on national and state statistics for installed capacity; electric generation and supply; sales, revenue and customers by class of service.
- NARUC - 1982, 1984 reports on utility and carrier regulation. Provides information about member agencies, ratemaking and other aspects of utility regulation by state and federal agencies.
- GRI - Survey of Electric Utility Ratebooks in 120 Cities. Provides summary of types of electric rates available in selected U.S. cities in the summer of 1984. Includes data on types of rates by use class, utility, seasonality of the rate, demand charges, and type of block structure.
- *Electrical World - Annual Generation Construction Survey.* Provides annual update of utility construction schedule. Includes data on unit ownership, capacity, service date, and percent of completion.

Background Note on the NERC Regions and DOE Electric Regions (subregions)

NERC was formed by the electric utility industry in 1968 after the historic Northeast blackout to promote the reliability and adequacy of power supply in the United States and Canada. NERC has nine regional councils comprising nearly all the electric utilities in North America. Both NERC and DOE have defined subregions to support smaller area analyses of power supplies. NERC Subregions and DOE Electric Regions were defined in accordance with historic associations among neighboring utilities, contractual and informal power pools, and practical system operating considerations. Figure 2 shows the location of NERC Regions and DOE subregions. Some States may belong to more than one Region or Electric Region. Three interconnected transmission networks provide distribution of electricity in the U.S.. (Appendix II) The Eastern Interconnected System (EIS) consists of about 99 control areas scattered through the seven eastern NERC regions; the Western Interconnected System (WIS) has about 34 control areas covering WSCC; and the Texas Interconnected System has about 10 operating in ERCOT.* (Ref 3)

Regional Indicators of Potential for New and Enhanced Energy Conservation Programs

Of the indicators defined to analyze the energy supply/demand balance, the ratemaking context, and the political/and institutional environment, we consider the six that best characterize the conditions when utilities will be favorable to energy conservation are: (1) High Oil Backout Potential, (2) Little or No Marginal Low-Cost Base Power (3) Relatively High Growth, (4) Early Need for New Capacity, (5) High Risk for New Power Plants (Low CWIP), and (6) Favorable Institutional Environment. The following is a brief description of each indicator at the level of aggregation we consider most meaningful and a summary of the results at the NERC Region and Electric Region level. The results of the indicators are highlighted in Figure 3(a) thru 3(f).

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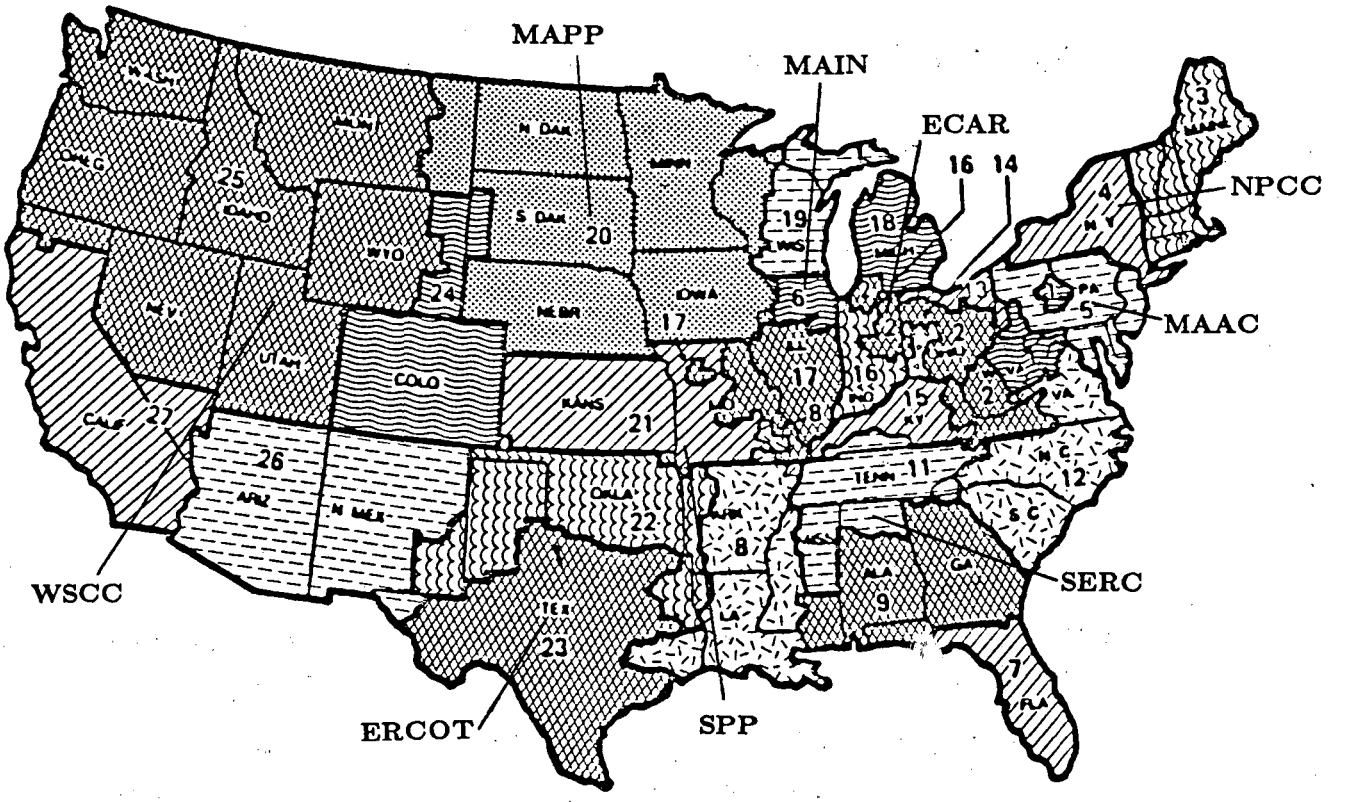
*Cooperation among utilities within interconnected systems takes place through sale of bulk power, power pools, wheeling, and joint projects. Through power exchange agreements, utilities try to minimize the cost of power and provide mutual assistance in the times of peak demand or equipment failure. Power pools are created by agreement between two or more utilities to coordinate their generation. They range from informal agreements (loose pools) to systems with coordinated planning and central dispatching systems (tight pools). Wheeling is the movement of electricity from one utility to another over transmission facilities owned by third party utilities. Such transmission is usually governed by contracts among the utilities involved. To minimize capital outlay and risk, construction of power plants or transmission facilities are increasingly accomplished by joint ventures among utilities. (Ref 4)

Figure 2.
NERC Regions and DOE Electric Regions



RELIABILITY COUNCIL/Electric Region

ECAR

1. APS (Allegheny Power System)
2. WOIM (West Virginia-Ohio-Indiana-Michigan System)
13. WPANCO (Western Pennsylvania-North Central Ohio Group)
14. CDH (Cincinti-Dayton-Hamilton Group)
15. KY (Kentucky Group)
16. IND (Indiana Group)
18. LMS (Lower Michigan Systems)

ERCOT

23. No Subregions

MAAC

5. No Subregions

MAIN

6. CECO (Commonwealth Edison Company)
17. SCIM (South Central Illinois-East Missouri Group)
19. WIUM (Wisconsin-Upper Michigan Systems Group)

MAPP

20. No Subregion

NPCC

3. NEPOOL (New England Power Pool)
4. NYPP (New York Power Pool)

SERC

7. FCG (Florida Electric Power Coordinating Group)
9. SOCO (Southern Company Group)
11. TVA (Tennessee Valley Authority)
12. VACAR (Virginia-Carolinas Group)

SPP

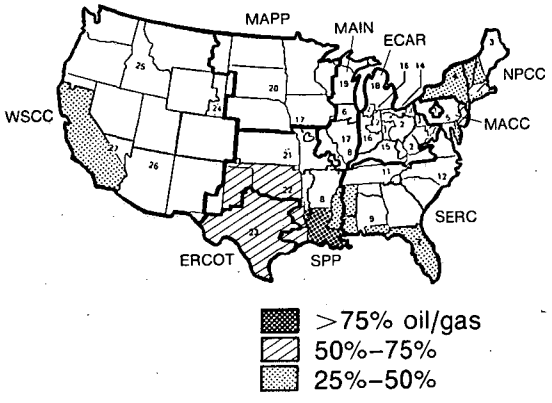
8. MSGS (Middle South-Gulf States Group)
21. MOKN (Missouri-Kansas Group)
22. OKLA (Oklahoma Group)

WSCC

24. RMPA (Rocky Mountain Power Area)
25. NWPP (Northwest Power Pool Area)
26. AZNM (Arizona-New Mexico Power Area)
27. CASN (California-Southern Nevada Power Area)

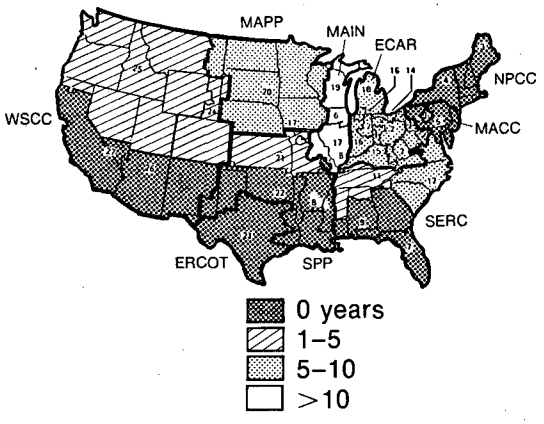
Selected Indicators of Potential for New and Enhanced Electric Utility Conservation Programs

a) High Oil/Gas Backout (POG)



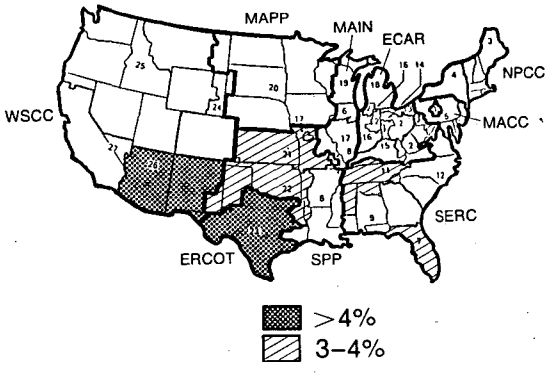
Source: 1984 State data

b) Little or No Marginal Low-Cost Power (Projected 1986 Estimate for YEARS)



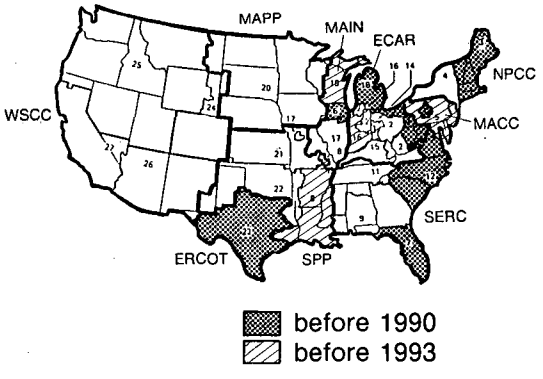
Source: DOE, 1984 Subregional data

c) Relatively High Growth 1984-1993 (GROWTH)



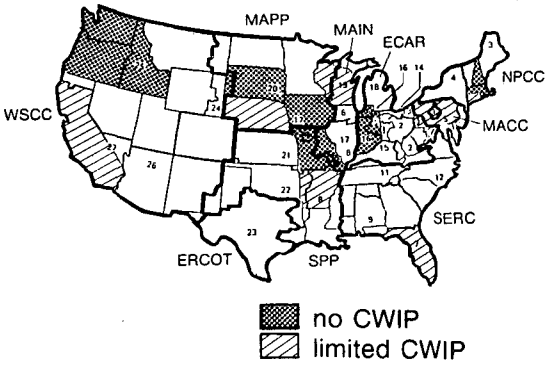
Source: NERC, 1984 Subregional data

d) Early Need for New Capacity – Case II (SubRYN-2)



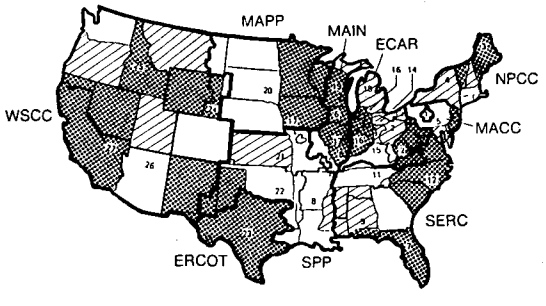
Source: DOE, 1984 Subregional data

e) High Risk for New Power Plants (Low or No CWIP)



Source: NARUC, 1984 State data

f) Institutions Favor Conservation



Require all cost-effective conservation
Conservation, load management incentives/ State assessment of conservation potential

Source: Schneider Survey, 1985 State data

High Oil Backout Potential

Following the 1973 Oil Crisis, utilities have embarked upon programs to use less expensive coal and nuclear fuels in order to decrease dependence on more expensive oil and natural gas. This was accomplished in part by conversion of oil fired-power plants to coal fuels, the addition of coal and nuclear power plants to substitute for existing oil/gas capability, and the implementation of conservation programs in the industrial and residential sectors. (See Appendix I). Although there is a short-term decline in world oil prices in the global market, utilities are remaining concerned about dependence on oil/gas due to the strategic nature of the fuel. The industry also expects that U.S. and global oil demand will again increase in the next decade, causing prices to increase.

As of 1983, coal and nuclear generation account for 64% and 15% respectively of total electricity generation compared with 53% and 5% a decade earlier. At the regional level (Appendix II), oil and gas generation decreased from 44% of total electricity generation in 1973 to just about 21% in 1983. (Ref 5) By 1990, coal is expected to account for 55% of total generation, nuclear 20%, with the share of oil and gas decreasing to 15% of total electricity generation. However, oil and gas fired generation is expected to again increase by about 1% in relative importance after 1990 because the proportion of electricity produced by nuclear power plants is expected to decline due to the tapering off of nuclear capacity additions. (Ref 6) Unused oil and gas baseload capacity may be brought into service again once capability from new power sources is exhausted by demand. (Ref).

Figure 3(a) shows percent of oil/gas generation to total total generation* among the states in 1984.* (Ref 7) At the regional level, oil and gas fired generation is expected to account for the largest share (40% - 60%) of total generation in the Northeast (NPCC - Rhode Island, Massachusetts, Connecticut, New York), and Southwest (ERCOT - Texas, SPP - Louisiana, Oklahoma); between 10 - 20% in the West (WSCC - primarily California) and the Mid-Atlantic States (MACC - New Jersey); and about 7% in the Southeast (SERC - primarily Florida). The pattern of fuel consumption among regions are not expected to change dramatically during 1984-1993 because the projected slowdown in capacity additions is expected to result in a greater reliance on existing capacity. (Ref 8) Planning for a possible shortage of critical fuels along with marginal cost considerations may prompt utilities in these Regions to consider conservation as an important aspect of their demand-side strategy.

Little or No Marginal Low-Cost Base Power

Utilities with excess low-cost marginal capacity have a near-term incentive to increase revenues because the primary cost associated with selling an additional kWh is fuel cost, which is usually lower than the average cost of electricity. They are unlikely to favor energy conservation because increased sales represent an opportunity to generate additional profits. In an environment of increasing marginal cost, utilities with little or no available cheap power will tend to favor conservation.

We define Potential Low-Cost Capacity (PLCC) as the potential to produce energy from all inexpensive generating facilities (hydro, nuclear, coal and imports) in excess of that needed to meet the utility's total demand. We assume in general imports will be lower-than-average cost power. Formally, PLCC is expressed as:

$$\text{PLCC} = \frac{[(\text{Maximum Coal Generation} + \text{Actual Nuclear Generation}^{**} + \text{Actual Hydro Generation}^{**} + \text{Actual Net Purchases}^{**}) - \text{Total Actual Net Generation}]}{\text{Total Actual Net Generation}}$$

* It should be noted that in 1984, oil and gas capability accounts for a greater proportion of total generating capacity than that reflected by data on actual generation because of the gradual shift in fuel sources. (See Appendix II).

where Maximum Coal Generation = Existing Coal Capacity x 8760 x .65 capacity factor.

If PLCC is equal to 0, there is sufficient low cost energy to meet demand. If PLCC is < 0, utilities have a shortage of cheap marginal energy. If PLCC is > 0, utilities have a surplus of inexpensive power.

Availability of low-cost marginal energy is affected by capacity utilization assumptions. Our utility level reference case used a coal capacity factor of .65. Changing the coal capacity factor to .60 or .70 will affect the YEARS estimate, especially in those regions with greater than 50% coal generation, e.g. ECAR, MAAC, and MAIN. (See Appendix V)

Where PLCC is > 0, we estimate the number of years (YEARS) until the available low-cost energy is used up using the average 1984-1993 growth rate projected for the region and subregion. If electricity demand growth rate is high, availability of low-cost capacity may represent a temporary surplus.*** We consider that conservation will serve as an option for meeting electricity demand so long as the supply of low-cost marginal energy is less than ten years - the time needed for construction and licensing of new coal and nuclear power plants.

YEARS is estimated for 1982 at the NERC Region, State and Utility level, and for 1983, 1986, 1990 at the NERC Region and Electric Region (subregion), and utility (1986, 1990 only) level. Of the available estimates, we consider the 1986 subregional estimate to be the most useful near-term indicator of potential utility interest in conservation. The subregional analyses provides a picture of how long-term firm contracts for power transfers among utilities may affect the need for low-cost power. We compared the 1986 estimates with 1990 subregional estimates to further refine our understanding of the trends in each Electric Region.

Figure 3(b) is a map of the 1986 YEARS estimate at the Electric Region (subregional) level. Based on 1983 data, the subregions projected to have no low-cost power in 1986 are located in:

ERCOT (Electric Region 23, Texas),
MAAC (Electric Region 5, Pennsylvania, New Jersey, Maryland),
NPCC (Electric Region 3, the New England States),

and portions of:

WSCC (Electric Region 26 - the Arizona-New Mexico Group,
Electric Region 27 - California-Southern Nevada Group),
SPP (Electric Region 8, Middle South Utilities/Gulf States Utilities Group,
and Electric Region 22, Oklahoma Group)
SERC (primarily Electric Region 7, Florida Coordinating Group,
and Electric Region 9, the Southern Company Group).

The subregions projected to have 1 to 5 years of low-cost power available are located in:

SERC - Electric Region 11, The Tennessee Valley Authority Group,
SPP - Electric Region 21, Missouri-Kansas Group,
WSCC (Electric Region 24, Rocky Mountain Power Pool, and
Electric Region 25, the Northwest Power Pool)

Surplus cheap power in these regions is expected to be used up given projected growth rates by 1990.

The three Electric Regions located in MAIN are expected to have greater than 10 years of surplus cheap power in 1986. They include Electric Region 6 - the Commonwealth Edison Co., Electric Region 17 - the Illinois-Missouri Group, and Electric Region 19 - the Wisconsin-Upper Michigan Systems Group. However, surplus low-cost power in MAIN is projected to decrease from 12 years by 1990 to less than 10 years if predicted conditions actually occur.

** Data for 1986, 1990 is based on utility forecasts published by NERC.

***The availability of low-cost capacity is sensitive to the electricity demand growth rate. See Appendix II for a comparison of the 1982 YEARS estimate using average growth rates for 1983-1992, 1984-1993, 1985-1994.

It should be noted that with the tapering off of nuclear capacity additions, capacity utilization for existing coal-fired and nuclear plants is expected to increase significantly between 1983 and 1995 in regions dependent on other more expensive fuels for electricity generation.

Relatively High Growth

The rate of growth of electricity demand plays a significant role in utility decision-making, as it influences electricity production, the type and quantity of fuel consumed, capacity expansion, reliability, financing, and end-use electricity prices. In general, electricity demand varies across consumer sectors (residential, commercial, industrial) and regions of the country. Demand in each sector can be influenced by economic conditions, weather, and income and price factors. Lower than expected demand growth exerts upward pressures on electricity prices as new plants come on stream and may result in the cancellation of new plants planned or under construction. Higher than expected rates of electricity demand increase the need for capacity to ensure reliable electricity supplies.

From 1980 through 1984, total electricity generation grew an average of 1.4 percent annually, less than half of the growth rate of gross national product for the period, as the result of less rapid growth in the residential and commercial sector and a sharp decline in the industrial sector demand. (Ref 9) DOE has projected that this trend will change in the mid-1980's, with electricity demand growth again to approximate growth in GNP. However, conservation, efficiency improvements and changes in industrial output mix could have significant impact on the level of future energy use per unit of industrial output and, in turn, affect the ratio of electricity growth to GNP growth in the 1990s.

Figure 3(c) shows the subregions where projected 1984-93 average annual net energy growth rates are greater than 3%. (Ref 10) The subregions with relatively high electricity demand growth (> 4%) are WSCC (Electric Region 26 - Arizona-New Mexico) and ERCOT (Electric Region 23 - Texas). SPP (Electric Region 21 and 22, Missouri-Kansas and Oklahoma Groups), and SERC (Electric Region 7 and 11, Florida Coordinating Group and Tennessee Valley Authority Group) have projected average electricity demand growth rates of >3%. It is expected that for some subregions, demand growth for the next decade may exceed planned capacity additions, resulting in additional reliance on marginal fuels such as oil and gas, imports, or unplanned capacity additions. For utilities operating in these areas, conservation may provide an alternative to other supply-side options to meet demand.

Early Need for New Capacity

Addition of new capacity is a lengthy and complex investment decision process. Such decisions involve the evaluation, among other factors, of a company's demand forecasts, capacity position, reliability reserve, and financial condition. Utilities subject to temporary financial stringency or a unfavorable regulatory climate may prefer to defer construction of new power plants.

The Surplus/Deficit indicator assesses the capability of utilities aggregated at the region and subregion level to meet demand and reliability requirements. Adjusted Reserve is defined by DOE as follows:

Adjusted Reserve = Planned capacity + Net Transfers - (Forced Outages + Scheduled Maintenance + Other Unavailability) - Peak.

We focused on data for years where adjusted reserves at the subregional level are less than 5% as the most favorable case for when utilities will be considering alternatives to meet reliability reserve requirements.* (Ref 11) Regional and subregional surplus/deficit (SUR/DEF, SHORT) is computed as capability (MW) in excess of or needed to meet a 5% reserve margin at the time of

* DOE used adjusted reserve margins of 5% - 7% as a reliability reference point. This is roughly equivalent to capacity margins of 15% - 20% used by the industry.

summer and winter peak demand (Appendix II, III). As in PLCC above, for regions with surplus capability, we estimate the Years Until New Capacity is Needed (RYN, SubRYN) for the time when surpluses will be used up given the demand growth rate in the region and subregion. RYN is estimated from regional data and represents the situation where there is a perfect market within the region that allows for ready energy transfers between surplus and deficit areas. SubRYN represents the case where surplus and deficits are fungible only within the subregion, and no trade outside the subregion is available. We prefer the Subregional estimates because they are more representative of actual power transfer arrangements and they also decrease the possibility of over-estimation of peak requirements from the use of non-coincident peak demand data.

We examine two cases of projected capacity additions. Case I is our analyses of when and where new capacity is needed based on DOE regional data for planned capability 1983-1992.

Under Case I, need for new capacity in the later half of the 1980's is projected for:

ECAR (Electric Regions 1, 13, 14, 18),
MAIN (Electric Region 6),
NPCC (Electric Region 3), and
SERC (Electric Regions 11, 12);

and in the early 1990's for:

MAPP (Electric Region 20), and
ERCOT (Electric Region 23).

Figure 3(d) shows timing of need for new capacity* among the Electric Regions under Case II. In Case II, planned capability is adjusted for nuclear power plants not in operation or likely to be canceled.** The near-term consequences of such reductions in planned capacity may be less reliable electricity supplies, additional power purchases, higher utility oil and natural gas consumption, and/or higher electricity prices. Projected shortages deepen for all affected regions in Case 1 and are expected to occur earlier for ERCOT (1989) and MAAC (1990). Several of these NERC Regions may need to institute conservation programs or plan for new capacity or purchases (provided adequate transmission facilities are available) at some peak periods during the coming decade if the predicted conditions actually occur.

A near-term alternative for some utilities faced with high marginal costs or near-term shortage of generating capacity may be the purchase of bulk power from low cost producers.*** Two factors will bear on the viability of this alternative: availability of adequate transmission facilities and the impact of acid-rain legislation on the cost of coal-fired generation. At present, transmission interties into areas that depend heavily on oil and gas appear to be operating at full utilization for imports and economy energy interchanges.**** (Ref 12) Numerous proposals to reduce

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* We present the higher of summer and winter estimates.

** We considered the following nuclear power plants as likely to be canceled: Midland 2 (ECAR), South Texas 2 (ERCOT), TMI-1 (1985 only), TMI-2, and Limerick 2 (MAAC), Seabrook 2 (NPCC), and Grand Gulf 2 (SPP). Recent decisions by the Pennsylvania Public Service Commission indicates that Limerick 2 (MAAC) now seem more likely to be completed.

*** Because of long leadtimes, all of the nuclear and most of the coal-fired units expected to be completed within the next ten years are already under construction. Licensing and construction take about 3 years for a turbine, 5 years for a hydroelectric unit, 8 years for a coal-fired steam plant, and 10-15 years for a nuclear unit.

**** "Transmission utilization is high within Northeast Power Coordinating Council (NPCC), although additional lines are being constructed in the area to import more power from Canada. A similar situation exists in MAAC, with heavy utilization of transmission capacity for economy interchange limiting interregional imports. The Florida sub-region of Southeastern Electric Reliability Council (SERC) is fully loaded for power imports, primarily from Georgia. In the Western Systems Coordinating Council, reliable transmission interchange limits are regularly reached between the Pacific Northwest and California, where upgrading of existing lines are planned. An additional high voltage line has been approved for construction within a scheduled in service date of 1990. Also within the western states, additional transmission access from the Rocky Mountain region to and from the Arizona/New Mexico power areas and between the Arizona/New Mexico power areas and California are required to make maximum efficient use of existing and planned generating facilities." (Ref 13)

sulfur dioxide (SO_2) emissions from coal-fired power plants by requiring utilities to install flue gas desulfurization equipment or to switch to lower sulfur coal have been introduced in Congress. These proposals would raise the cost of coal-fired generation and affect both electricity prices and coal producers. Price increases would be particularly significant in coal-dependent regions "east of or bordering on" the Mississippi River, dampening electricity demand. Depending upon the requirements of the specific proposal enacted, coal markets could also be significantly affected, with low-sulfur coal regions of the country (Central Appalachia and the Northern Plains, for example) gaining markets if coal switching is allowed and less expensive high-sulfur coal regions (such as Northern Appalachia and the Midwest) maintaining markets if FGD installation becomes mandatory. (Ref 14)

High Risk for New Power Plants (Low CWIP)

Inclusion of generating capacity in the rate base is traditionally qualified by the criteria that the unit be "in use and useful" in meeting current demand. In the ratemaking process, the costs of financing power plants under construction are treated by public service commissions either as an Allowance for Funds Used During Construction (AFUDC) or Construction Work in Progress (CWIP). Under AFUDC, financing charges are capitalized and added to the total costs of the unit. As the facility is included in the rate base, the utility earns a return on the total cost after depreciation. Given the lengthening construction period for new power plants, utilities are increasingly advocating the partial or total inclusion of financing costs in the rate base as they occur (CWIP) to improve their cash flow during the construction period.*

From the perspective of utilities examining conservation as a demand-side option, if the full cost of financing new power plant construction is allowed in the rate base, the long-term attractiveness of conservation, when compared with new construction as a way of balancing supply and demand, will decline because this treatment of financing costs reduces the economic disincentive for building additional capacity. Current regulatory rules for CWIP accounts vary among the individual states. (Ref 15) Generally, states allow a small percentage of CWIP accounts to enter the rate base.** (see Appendix IV) Figure 3(e) shows the location of states that disallowed or limited CWIP in 1984***: They are:

NPCC (New Hampshire, Massachusetts, Connecticut, and Rhode Island)
WSCC (Washington, Oregon, Idaho, California),
MAPP (S. Dakota, Nebraska, Iowa),
SPP (Missouri, Arkansas),
ECAR (Indiana),
MACC (Pennsylvania),
and SERC (Florida).

It is important to keep in mind that regulatory policy is this arena is very volatile; state public service commissions may expand or contract allowance of CWIP based on their evaluation of both the need for new capacity and a utility's financial condition.

Favorable Political/Institutional Environment

Investor-owned utilities (IOUs) operate under a grant of franchise monopoly from state public service commissions and municipal authorities. Such agencies routinely exercise regulatory power over entry prices, and services in the electric utility industry. Their interest in promoting energy conservation, along with "need for power" reviews that critique utility construction

* By reducing the total amount of interest capitalized, allowance of CWIP may lessen the consumer "rate shock" caused by introduction of expensive new capacity into the rate base. Depending on the amount of CWIP allowed, the current consumer may pay a relatively higher rate to provide a return to the utility.

** FERC may permit up to 50 percent of financing costs in the rate base.

*** We aggregate state data to NERC Regions by applying a generation- weighted factor. (See Appendix II)

programs and management practices, have been a significant factor in spurring the development of conservation programs by IOUs. In FY 1985, we updated the indicators used for the Political and Institutional Factor with data from a recent survey of state energy planning and conservation activities sponsored by the Office of Congresswoman Claudine Schneider. The purpose of the Schneider survey was to determine the information needs of state regulatory commissions in implementation of a "Least-Cost Energy Strategy." (Ref 16, 17). The five indicators we selected, in order of decreasing signficance as indicators of a favorable environment for conservation, are:

(1) Utilities are required to invest in conservation prior to new energy resources (INVEST),

(2) Commission offers conservation/load management incentives (INCENT),

(3) State-conducted assessment of conservation potential (ASSESS),

(4) Demand-side options are included in a required utility resource plan (OPTIONS)

(5) State has statutory authority to require utility investment in energy conservation or load management (STAT).

Nineteen states have required utilities to demonstrate that they are employing all cost-effective conservation and load management measures before investing in new energy sources. Eleven commissions offer conservations and load management incentives to utilities; and twenty-eight states have conducted independent asssessments of conservation potential. In addition, utilities in seventeen states have included demand-side options in their utility resource plans and twenty-nine state regulatory commissions have statutory authority to require utility investment in energy conservation or load management. Figure 3(f) summarizes the results of our analyses. The states considered to have the most favorable institutional environments are located in:

ECAR (Indiana, Michigan, Ohio);
ERCOT (Texas),
MACC (New Jersey, Pennsylvania, Maryland);
MAIN (Wisconsin, Illinois, Michigan);
MAPP (Iowa, Minnesota); and
NPCC (Maine, Vermont, Delaware, New Hampshire, Connecticut, Massachusetts, New York);
SERC (Virginia, North Carolina, South Carolina, Florida, Alabama, Mississippi);
SPP (Kansas, Texas).
WSCC (California, Nevada, Idaho, Wyoming, Oregon, Montana, New Mexico);

Combining the Regional Indicators

The economic impact on energy conservation on electric utilities consists of changes in projected revenue resulting from lost sales and avoided costs. In the short run, if conservation reduces peak demand, it will increase the profitability of total electricity sales by lowering average production costs. In the long run, conservation may involve load shape changes that shift the balance between peak and base load generation. If peak load growth declines more than base load, the impact of earnings is positive because of lower average costs. Conversely, average production costs will increase if the peak-to-base ratio is higher.

Figure 4 shows a number of possible Least-Cost options for utilities operating under different energy and capacity scenerios. For utilities with no or low marginal low-cost energy and need for new capacity, there is an incentive for near-term adoption of both demand reduction and capacity enhancement programs. For utilities with a temporary surplus of cheap power and projected need for new capacity, capacity-enhancing options may be more appealing in the short term. Such options include purchasing power from lower-cost producers or cogenerators, and joint venturing with other utilities for construction of new power plants or transmission facilities. For utilities with excess low cost power

Figure 4.

LEAST-COST SUPPLY STRATEGIES* FOR DIFFERENT UTILITY SUPPLY/DEMAND BALANCE SCENARIOS BASED ON ENERGY AND CAPACITY INDICATORS

Early Need for New Capacity (SubRYN), (+)

(I)

YEARS < 10; SubRYN Before 1993

- Near term interest in both DEMAND REDUCTION and CAPACITY ENHANCING measures

(II)

YEARS > 10; SubRYN Before 1993

- Near term emphasis on CAPACITY ENHANCING measures
- Long Term interest in DEMAND REDUCTION alternatives

(-) (+) Years Until Expensive Energy is Needed (YEARS)

(III)

YEARS < 10; SubRYN after 1993

- Near term emphasis DEMAND REDUCTION alternatives
- Long term interest in CAPACITY ENHANCING measures

(IV)

YEARS > 10; SubRYN after 1993

- Primary interest in increasing sales
- Possible interest in DEMAND-SIDE RESEARCH to maximize future options

(-)

*Least-Cost demand reduction strategies generally include conservation, load management, and passive solar; capacity enhancing measures cover coal conversion, small power facilities and cogeneration, increasing power plant productivity, and power pooling & transmission.

See U.S. House Representatives "A Perspective on Electricity Capacity Planning." Report prepared by the Congressional Research Service for the use of the Subcommittee on Energy Conservation and Power, Committee on Energy and Commerce. August 1983.

and no requirement for new capacity in the foreseeable future,
the primary focus will probably be to increase sales and link up with new markets through the construction of new transmission facilities and/or wheeling arrangements. Demand-side research will be appropriate in the context of maximizing utility options for the time when existing units are retired and/or growth accelerates beyond expected demand.

In combining the operation of the selected indicators, we consider marginal energy cost of baseload generation to be the most influential factor determining the near-term potential for conservation among investor-owned utilities. Need for new capacity will reinforce the potential for conservation in regions where there is no low-cost energy and promote consideration of strategic conservation programs where there are temporary surpluses. Active interest in conservation by public service commissions together with a favorable ratemaking environment will encourage the early adoption of conservation programs.*

Figure 5 summarizes the result of the six indicators for the NERC regions. The economic indicators characterizing "availability of low-cost energy" and "need for new capacity" are weighted the key indicators of merit. This might be characterized as an "avoided-cost push" perspective of conservation for utilities operating under a capital minimization constraint. There is a clear need now to consider conservation in Group A: Texas (ERCOT - Electric Region 23), the mid-Atlantic (MAAC - Electric Region 5), the Northeast (NPCC - Electric Region 3 and 4), Florida (SERC - Electric Region 7), the Mid-South (SPP - Electric Region 8), and the West (WSCC - Electric Regions 25, 26, and 27). Also, on economic grounds, the potential for conservation is good in Group B, which includes SERC - Electric Regions 9 and 11 (Southern Company and TVA), SPP - Electric Regions 21 (Missouri-Kansas) and 22 (Oklahoma), and WSCC - Electric Regions 24 (Rocky Mountain).

Group C represents regions that are borderline favorable to conservation. They include Electric Regions in ECAR (1, 13, 14, 16 18), MAPP (20), and SERC (12) that have an estimated 5 to 10 years of surplus low-cost energy. Some Electric Regions in ECAR and SERC are expected to need additional new capacity by the early 1990's. Utilities in these areas may consider appropriate "least-cost" capacity-enhancing alternatives along with conservation research at this time.

Utilities within regions belonging to Group D are considered unlikely to implement conservation programs in the near term. The availability of CWIP in Electric Regions 2 and 15 (ECAR), combined with an expected 5 to ten years surplus of low-cost energy, would also make conservation a less competitive option in the long term compared with construction of small power plants. There may be some tension in the short term between the institutional environment and economic reality for Electric Regions in MAIN. For 1986, Electric Regions 6, 17, 19 in MAIN is projected to have greater than 10 years of low-cost surplus energy. PUCs in these regions seem to favor conservation, whereas the economics of excess low-cost capacity would tend to push utilities to promote greater sales. Utility interest in conservation for MAIN may become more favorable after the 1990s when the region will have less than 10 years of surplus low-cost power and a need for new capacity to ensure reliability of power supply.

Figure 6 shows the geographical distribution of Electric Regions according how favorable they are to new and enhance utility conservation programs in 1986.

Limitations of the Regional Analyses and Need for Further Research

The purpose of our regional analysis is to segment the market for energy conservation among investor-owned utilities having different system characteristics to support DOE policy and program planning efforts. The indicators selected focused on key economic measures of avoided costs, and provide a qualitative review of the ratemaking and institutional environment.

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* In this context, examining whether the existing rate structure for the utility is favorable to a specific conservation program under consideration will indicate the need for further regulatory adjustments prior to implementation of the conservation program. (See Appendix V for selected utility level Rate Structure (RATES) indicators.)

Figure 5.

FAVORABLE TO CONSERVATION - 1986

NERC Reliability Region	DOE Electricity Region	Identification	High Oil Backout	No Low-Cost Power	High Demand Growth	Early Need for Cap	No/Low CWIP	Favorable Inst.	Composite Rating
ECAR	1	Allegheny Power Systems (APS)		~		+		+	C
	2	W. Va-Ohio-Ind-Mich Systems (WOIM)		~				+	D
	13	W. Pa-No. Central Ohio (WPANCO)		~		+		+	C
	14	Cincinnati-Dayton-Hamilton (CDH)		~	+		+	+	C
	15	Kentucky Group (KY)		~				+	D
	16	Indiana Group		~		+	+	+	C
	18	Lower Michigan Systems		~	+	+		+	C
ERCOT	23	Texas Interconnected Systems Group (TIS)	+	+	+	+		+	A
MACC	5	Pennsylvania-New Jersey-Maryland Interconnection (PJM)		+		+			A
MAIN	6	Commonwealth Edison Co. (CECO)				+		+	D
	17	Illinois-Missouri Group (ILLMO)						+	D
	19	Wisconsin-Upper Michigan Systems Group (WUMS)				+		+	D
MAPP	20	Mid-Continent Area Power Pool		~			+	+	C
NPCC	3	New England Power Pool (NEPOOL)	~	+		+	+	+	A
	4	New York Power Pool (NYPP)	~	+			+	+	A
SERC	7	Florida Coordinating Group (FCG)	~	+	+	+		+	A
	9	Southern Company Group (SOCO)		+					B
	11	Tennessee Valley Authority Group (TVA)		+	+	+			B
	12	Virginia-Carolina Group (VACAR)		~		+		+	C
SPP	8	Middle South Utilities/Gulf States Utilities Group (MSGS)	+	+		+	+	~	A
	21	Missouri-Kansas Group (MOKAN)		+	+		+	+	B
	22	Oklahoma Group (OKLA)	+	+	+			+	B
WSCC	24	Rocky Mountain Power Pool (RMPP)		+				~	B
	25	Northwest Power Pool (NWPP)		+				+	A
	26	Arizona-New Mexico Group (AZNM)		+	+			+	A
	27	California-So. Nevada (CASN)	+	+			+	+	A

Indicators: + - Very Favorable; + - Favorable; ~ - Borderline Favorable

Capacity Rating: A - Very Favorable; B - Favorable; C - Borderline Favorable; D - Unfavorable

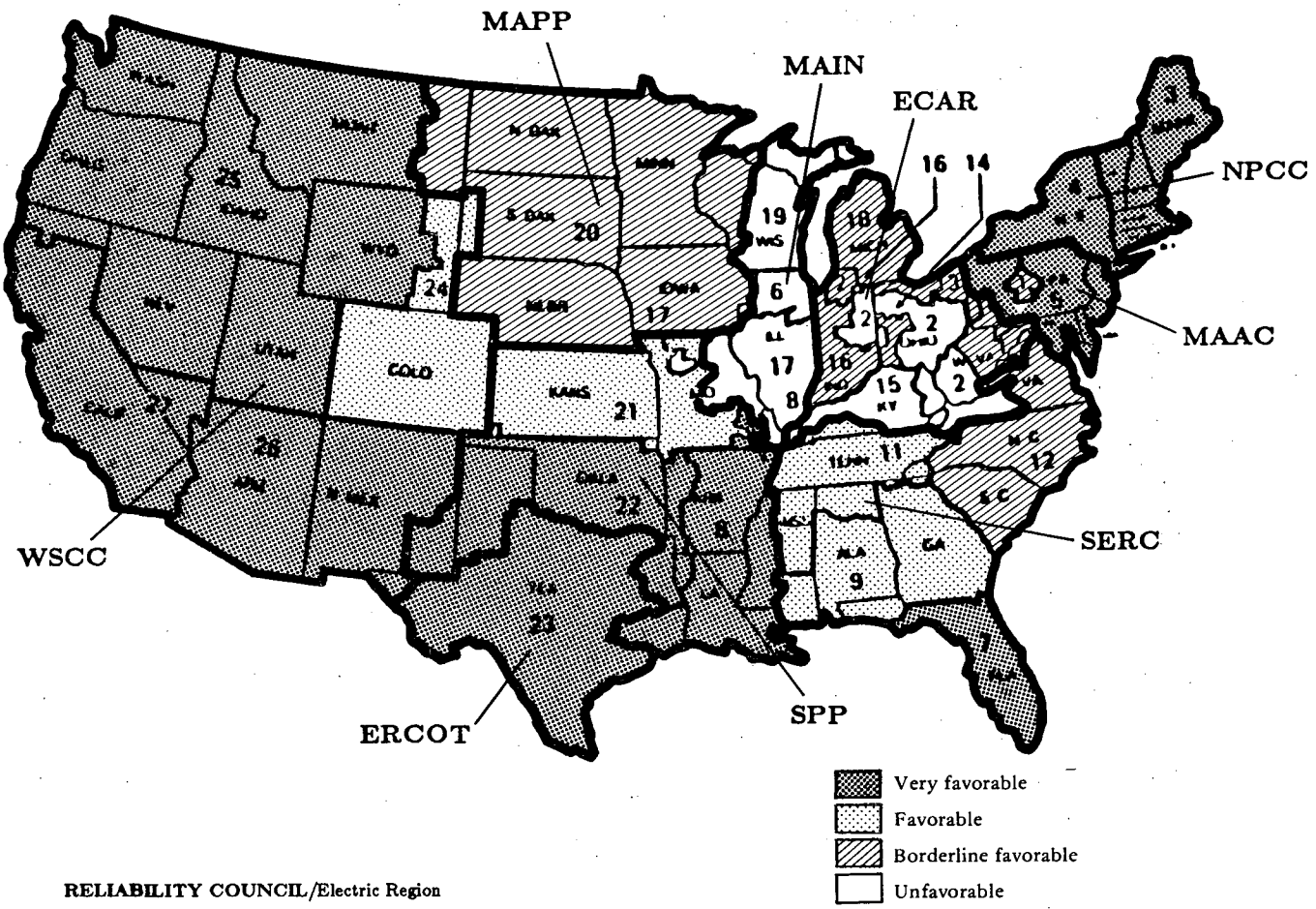
Source: LBL Report LBL -21056

Note: To derive the composite rating, we assigned the following numerical weights and scales to selected indicators. Scales for each indicator are shown in parenthesis, in the order for "very favorable," "favorable," and "borderline favorable."

1. High Oil Backout = 1, (3, 2, 1)
2. No Low-Cost Power = 5, (5, 3, 1)
3. High Demand Growth = 1, (3, 2, 1)
4. Early Need for New Capacity = 1.5, (3, 2, 1)
5. No/Low CWIP = 1, (3, 2, 1)
6. Favorable Institutional Environment = 1, (3, 2, 1)

For the composite rating, Very Favorable is A = > 27; Favorable is B = 18 to 26; Borderline Favorable is C = 9 to 17; Unfavorable is D = 0 to 8.

Figure 6.
Favorable to Conservation - 1986



RELIABILITY COUNCIL/Electric Region

ECAR

1. APS (Allegheny Power System)
2. WOIM (West Virginia-Ohio-Indiana-Michigan System)
13. WPANCO (Western Pennsylvania-North Central Ohio Group)
14. CDH (Cincinnati-Dayton-Hamilton Group)
15. KY (Kentucky Group)
16. IND (Indiana Group)
18. LMS (Lower Michigan Systems)

ERCOT

23. No Subregions

MAAC

5. No Subregions

MAIN

6. CECO (Commonwealth Edison Company)
17. SCIM (South Central Illinois-East Missouri Group)
19. WIUM (Wisconsin-Upper Michigan Systems Group)

MAPP

20. No Subregion

NPCC

3. NEPOOL (New England Power Pool)
4. NYPP (New York Power Pool)

SERC

7. FCG (Florida Electric Power Coordinating Group)
9. SOCO (Southern Company Group)
11. TVA (Tennessee Valley Authority)
12. VACAR (Virginia-Carolinas Group)

SPP

8. MSGS (Middle South-Gulf States Group)
21. MOKN (Missouri-Kansas Group)
22. OKLA (Oklahoma Group)

WSCC

24. RMPA (Rocky Mountain Power Area)
25. NWPP (Northwest Power Pool Area)
26. AZNM (Arizona-New Mexico Power Area)
27. CASN (California-Southern Nevada Power Area)

XBL 865-9176

In the next step, actual design and selection of conservation programs will require the analyst to address problems of benefits and costs at the utility level. Such decisions are influenced by utility-specific objectives in an embedded regulatory environment. (See Appendix V) Utility management's disposition of conservation proposals will be dependent on their perceptions of program costs and benefits compared with other economic alternatives. (Ref 19)

A number of issue areas have emerged which will be of concern to policy-makers in the implementation of conservation and other least-cost energy initiatives.* They include: (1) uncertain impact on and customer response to load shape; (2) disparate allocation of conservation program costs and benefits among utility shareholders, program participants and general ratepayers; (3) institutional inertia; and (4) Long-term effect of small power production/cogeneration. We will discuss ongoing and proposed research at LBL in each of these areas briefly below.

Uncertain Impacts and Benefits on Load Shape

While utilities have well-developed techniques for planning and operating power supply facilities, the techniques for influencing demand are relatively new, as are those for analyzing the impact of conservation programs on utility earnings. Unlike power plant investments, the success of end-use programs are dependent on their acceptance by consumers. Many utilities are developing computer programs to model customer response to different initiatives and to estimate the revenue impact of expected changes in load shape associated with different end-use programs. (Ref 20) Analysis of the financial impact of conservation on electric utilities must take into account the different sales profiles and tariff structures applicable to individual utilities. The LBL Utility Case Studies carried out in FY 1984-85 examined the impact of conservation on utilities with different system characteristics. (Ref 21,22) The studies concluded that conservation impacts are generally unfavorable for Detroit Edison, a utility with "excess low-cost capacity"; while they will help to defer the need for new capacity at PG&E, a utility dependent on oil and gas as a marginal source of fuel. It also found that PG&E programs targeted at summer peak demand were more beneficial than those which save baseload energy. Additional case studies are being carried out for Texas Power and Light and Nevada Power. Another LBL study is evaluating the hands-on application of two computer models developed to analyze generation expansion (EGEAS) and load management alternatives (LMSTM) for comparing supply and demand-side options. A third project, jointly funded by PG&E and DOE, examines methodological issues associated with demand-side management programs for a large utility. When completed, these studies will provide useful information for the development of conservation programs and Least-Cost initiatives.

Equity Issues Associated with the Development of Conservation Programs

For investor-owned utilities, the underlying rationale for offering incentives is based upon the concept that the revenue loss is less than long-run avoided costs. (Ref 23) In the absence of any incentive, the difference flows to the general class of ratepayers. Many questions of a distributional nature arise when utilities promote conservation. At issue is the the disparate allocation of costs and benefits to the interested parties, e.g. the utility shareholder, the program participant, and the general ratepayer. Some utilities have preferred load management to end-use programs because of more predictable results and revenue impacts. (Ref 24). Others have focused on incentives for the residential sector rather than the more productive commercial or industrial sector due to political considerations. (Ref 25). Different ratemaking practices - e.g., expensing regulations, fuel pass through clauses, and automatic reimbursement of revenue lost through conservation, will encourage development of conservation programs favorable to one or another group.

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* The National Association of Regulatory Utility Commissioners' Ad Hoc Committee on Energy Conservation identified the following issues for which the greatest need for information was indicated: They are: (1) estimation and verfication of cost savings; (2) deferral of capacity; (3) costs of conservation measures; (4) equity concerns; (5) treatment of conservation expenses; (6) technical and economic conditions for conservation; (7) reduced capacity; (8) consumer behaviorial characteristics. See 1983 and 1984 Report of the Ad Hoc Committee on Energy Conservation, National Association of Regulatory Utility Commissioners. (Ref 18).

Examining how equity issues associated with conservation programs are resolved by utilities with different regulatory constraints will support further development of regulatory policies.

Institutional Inertia and Regional Energy Planning

A key finding of the Utility Overview Study is that potential interest in conservation differs widely among NERC Regions accordings to their fuel resources, installed capacity, and energy demand. At present, the institutional framework at the state and regional level consists of regulatory commissions, transmission control areas, power pools, and reliability councils. In the context of Least-Cost initiatives, it is not always easy or practical for utilities to perceive economic rationality near the margin. Many considerations come into play when utilities make investments; there is a reluctance on the part of people and institutions to make changes or to scrap existing equipment even if such changes appear to be economically feasible. (Ref 26). Broad-base dialogues focused on local energy supply and demand and economic development or enviromental concern may reduce such inertia and add impetus to favorable economic potential. Some movement in this direction has already occurred under the auspices of the National Governors' Association and the Northwest/Midwest Congressional Coalition which has set up a task force to examine "issues of widespread concern over price and supply of energy" on a regional basis.* Bills authorizing states to enter into compacts to develop conservation and electric power plans and regulate certain rates for bulk power were introduced in both the 98th and the 99th Congress.** (Ref 28). A useful follow-up project to the Overview Study is to identify common regional concerns related to the energy supply/demand balance among the regions favorable to conservation and institutional mechanisms that would support collaborative development of conservation as a least-cost option.

Utility Response to Small Power Production/Cogeneration

The Public Utility Regulatory Act (PURPA, P.L 95-617) of 1978 exempted qualifying facilities (< 80 MW) from rate regulation and established incentives to encourage the development of cogeneration and small power production facilities, including wind machines and small hydropower installations. The rules promulgated by FERC to implement PURPA provided that utilities must purchase electricity from qualifying cogenerators and small power producers at a marginal price defined as its "avoided cost." Avoided cost is to reflect the costs of fuel and capacity construction that a utility can avoid by purchasing power from cogenerators and small power producers.

Uncertainties in the electric demand growth rate and difficulties in financing and siting new baseload facilities have made small additions to capacity attractive to utilities in the short term by allowing them to achieve a closer match between supply and demand. However, the advent of small power producers, particularly cogenerators, may raise some fundamental questions for the electric utility industry as a regulated monopoly. Cogeneration has added to the uncertainty of forecast demand because it has introduced the spectre of the utilities' industrial and commercial customers becoming their suppliers. Possibly as much as 5 to 20 percent of U.S. electricity consumption could be supplied by non-utility cogeneration sources by the year 2000. (Ref 29). In general, high fuel prices and economic growth would tend to increase market potential of small power producers/cogenerators, while increased conservation or lower avoided-cost fuel prices would tend to reduce it. To protect their market share, utilities may adopt conservation to narrow the potential market of small power producers or become themselves qualifying facilities to

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* See Ref 27. An important precedent for this is the Pacific Northwest Power Planning and Conservation Act of 1980, (P.L.), which expands the obligation of the Bonneville Power Administration to service publicly-owned and investor-owned utilities as well as its directly serviced industries. The intention of the Act is to provide the Pacific Northwest with an adequate power supply, stablize utility rates, and place maximum reliance on conservation and renewable energy resources while responding to electricity demand growth. (Ref 27).

** See "Regional Conservation and Electric Power Planning and Regulatory Coordination Act of 1984", H.R. 5766, 98th Congress, Second Session. Representative Jeffers (Vermont) has also introduced a bill in the current session of Congress (H.R. 3074) to authorize voluntary interstate compacts for coordination of conservation efforts.

participate in more profitable unregulated sales.* (Ref 30). Local economic and political conditions will significantly influence utility choice of strategies as they shift from being suppliers of electricity towards that of providers of "energy services". Analyzing the entry of cogeneration into the market, and how utilities adapt, will support development of appropriate public policies at the state and national level.

* The potential for small power facilities may decrease with the curtailment of tax incentives under various proposals for deficit reduction legislation.

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