renewable sources of power. Demand for fossil fuels surely will overrun supply sooner or later, as indeed it already has in the case of United States domestic oil drilling. Recognition also is growing that our air and land can no longer absorb unlimited quantities of waste from fossil fuel extraction and combustion. As that day draws nearer, policymakers will have no realistic alternative but to turn to sources of power that today make up a viable but small part of America's energy picture. And they will be forced to embrace energy efficiencies – those that are within our reach today, and those that will be developed tomorrow. Precisely *when* they come to grips with that reality – this year, 10 years from now, or 20 years from now – will determine how smooth the transition will be for consumers and industry alike.

BURLINGTON RESOURCES

(-84)

B.S. Shackouls
Chairman, President and
Chief Executive Officer

February 21, 2000

Mr. Joe Kelliher
Senior Advisor to the Secretary
Office of the Secretary
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Kelliher:

As chairman of the Domestic Petroleum Council, and also on behalf of our Vice Chairman, Ray Seegmiller, and all of us who met with you last week, I want to thank you for taking the time to do so. We appreciated being able to discuss our current natural gas situation and what it will take to meet the dramatically increasing future demand. We were also glad to be able to provide our thoughts on the importance of the Gulf of Mexico Lease Sale 181.

The large independent exploration and production company members of the DPC will continue to do all we can to find and produce the natural gas our consumers need in order to maintain a healthy economy. We will also work closely with you and other members of the Administration and Congress toward the coordinated and comprehensive natural resource and energy policies our nation needs. The insights you provided concerning some ways we may be of most help in working toward our common energy goals were most welcome.

Please do not hesitate to let any of us who met with you know if we can answer other specific questions or discuss other issues anytime.

Sincerely,

Bob S Shackouls

c: Ray Seegmiller, Chairman, President & CEO, Cabot Oil & Gas
  and DPC Vice Chairman
 William F. Whitsitt, DPC President
 Gavin H. Smith, Vice President, Burlington Resources
 Greg Moredock, Director, Government Relations & Regulatory Affairs, Cabot Oil & Gas

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The White House

Office of the Press Secretary

For Immediate Release September 27, 1993

Fact Sheet
Nonproliferation And Export Control Policy

The President today established a framework for U.S. efforts to prevent the proliferation of weapons of mass destruction and the missiles that deliver them. He outlined three major principles to guide our nonproliferation and export control policy:

- Our national security requires us to accord higher priority to nonproliferation, and to make it an integral element of our relations with other countries.

- To strengthen U.S. economic growth, democratization abroad and international stability, we actively seek expanded trade and technology exchange with nations, including former adversaries, that abide by global nonproliferation norms.

- We need to build a new consensus - embracing the Executive and Legislative branches, industry and public, and friends abroad - to promote effective nonproliferation efforts and integrate our nonproliferation and economic goals.

The President reaffirmed U.S. support for a strong, effective nonproliferation regime that enjoys broad multilateral support and employs all of the means at our disposal to advance our objectives.

Key elements of the policy follow.

Fissile Material

The U.S. will undertake a comprehensive approach to the growing accumulation of fissile material from dismantled nuclear weapons and within civil nuclear programs. Under this approach, the U.S. will:

- Seek to eliminate where possible the accumulation of stockpiles of highly-enriched uranium or plutonium, and to ensure that where these materials already exist they are subject to the highest standards of safety, security, and international accountability.

- Propose a multilateral convention prohibiting the production of highly-enriched uranium or plutonium for nuclear explosives purposes or outside of international safeguards.

- Encourage more restrictive regional arrangements to constrain fissile material production in regions of instability and high proliferation risk.

- Submit U.S. fissile material no longer needed for our deterrent to inspection by the International Atomic Energy Agency.

- Pursue the purchase of highly-enriched uranium from the former Soviet Union and other countries and its conversion to peaceful use as reactor fuel.

- Explore means to limit the stockpiling of plutonium from civil nuclear programs, and seek to minimize the civil use of highly-enriched uranium.

- Initiate a comprehensive review of long-term options for plutonium disposition, taking into account technical, nonproliferation, environmental, budgetary and economic considerations. Russia and other nations with relevant interests and experience will be invited to participate in this study.

The United States does not encourage the civil use of plutonium and, accordingly, does not itself engage in plutonium reprocessing for either nuclear power or nuclear explosive purposes. The United States, however, will maintain its existing commitments regarding the use of plutonium in civil nuclear programs in Western Europe and Japan.

Export Controls

To be truly effective, export controls should be applied uniformly by all suppliers. The United States will harmonize domestic and multilateral controls to the greatest extent possible. At the same time, the need to lead the International policy interests may justify unilateral export controls in specific cases. We will review our unilateral dual-use export controls and policies, and eliminate them unless such controls are essential to national security and foreign policy interests.

We will streamline the implementation of U.S. nonproliferation export controls. Our system must be more responsive and efficient, and not inhibit legitimate exports that play a key role in American economic strength while preventing exports that would make a material contribution to the proliferation of weapons of mass destruction and the missiles that deliver them.

Nuclear Proliferation

The U.S. will make every effort to secure the indefinite extension of the Non-Proliferation Treaty in 1995. We will seek to ensure that the International Atomic Energy Agency has the resources needed to implement its vital safeguards responsibilities, and will work to strengthen the Iaea's ability to detect clandestine nuclear activities.

Missile Proliferation

We will maintain our strong support for the Missile Technology Control Regime. We will promote the principles of the Mtcr Guidelines as a global missile nonproliferation norm and seek to use the Mtcr as a mechanism for taking joint action to combat missile proliferation. We will support prudent expansion of the Mtcr's membership to include additional countries that subscribe to international nonproliferation standards, enforce effective export controls and abandon offensive ballistic missile programs. The United States will also promote regional efforts to reduce the demand for missile capabilities.

The United States will continue to oppose missile programs of proliferation concern, and will exercise particular restraint in missile-related cooperation. We will continue to retain a strong presumption of denial against exports to any country of complete space launch vehicles or major components.

The United States will not support the development or acquisition of space-launch vehicles in countries outside the Mtcr.

For Mtcr member countries, we will not encourage new space launch vehicle programs, which raise questions on both nonproliferation and economic viability grounds. The United States will, however, consider exports of Mtcr-controlled items to Mtcr member countries for peaceful space launch programs on a case-by-case basis. We will review whether additional constraints or safeguards could reduce the risk of misuse of space launch technology. We will seek adoption by all Mtcr partners of policies as vigilant as our own.

Chemical and Biological Weapons

To help deter violations of the Biological Weapons Convention, we will promote new measures to provide increased transparency of activities and facilities that could have biological weapons applications. We call on all nations -- including our own -- to ratify the Chemical Weapons Convention quickly so that it may enter into force by January 13, 1995. We will work with others to support the international Organization for the Prohibition of Chemical Weapons created by the Convention.

Regional Nonproliferation Initiatives

Nonproliferation will receive greater priority in our diplomacy, and will be taken into account in our relations with countries around the world. We will make special efforts to address the proliferation threat in regions of tension such as the Korean peninsula, the Middle East and South Asia, including efforts to address the underlying motivations for weapons acquisition and to promote regional confidence-building steps.

In Korea, our goal remains a non-nuclear peninsula. We will make every effort to secure North Korea's full compliance with its nonproliferation commitments and effective implementation of the North-South denuclearization agreement.

In parallel with our efforts to obtain a secure, just, and lasting peace in the Middle East, we will promote dialogue and confidence-building steps to create the basis for a Middle East free of weapons of mass destruction. In the Persian Gulf, we will work with other suppliers to contain Iran's nuclear, missile, and Cbw ambitions, while preventing reconstruction of Iraq's activities in these areas. In South Asia, we will encourage India and Pakistan to proceed with multilateral discussions of nonproliferation and security issues, with the goal of capping and eventually rolling back their nuclear and missile capabilities.

In developing our overall approach to Latin America and South Africa, we will take account of the significant nonproliferation progress made in these regions in recent years. We will intensify efforts to ensure that the former Soviet Union, Eastern Europe and China do not contribute to the spread of weapons of mass destruction and missiles.

Military Planning and Doctrine

We will give proliferation a higher profile in our intelligence collection and analysis and defense planning, and ensure that our own force structure and military planning address the potential threat from weapons of mass destruction and missiles around the world.

Conventional Arms Transfers

We will actively seek greater transparency in the area of conventional arms transfers and promote regional confidence- building measures to encourage restraint on such transfers to regions of instability. The U.S. will undertake a comprehensive review of conventional arms transfer policy, taking into account national security, arms control, trade, budgetary and economic competitiveness considerations.

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America's Oil and Gas Producers

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Federal Financial Instruments

During periods of low oil prices, independent producers and support companies – particularly smaller ones – need flexible financial instruments to carry them through the price downturn. Currently, the primary source of external financing is bank loans. These loans must comport with banking regulations and, when prices are low as they were in 1998 and early 1999, harsh choices have to be made that put many producers and support companies out of business. This recent price crisis has resulted in new options being developed.

DOE and SBA Program – The Department of Energy and the Small Business Administration have negotiated a memorandum of understanding to facilitate the use of financing options available under the agency's small business assistance programs. This is an important recognition of the need to develop federal financial instruments to help small producers. Nevertheless, this option is limited due to a number of factors including small producers' unfamiliarity with the programs, the relatively small value of the loans (usually less than $1 million), the reluctance of most banks to make loans to businesses engaged in natural resource extraction (even with 75 percent guarantees), and the fees, red tape, and other paperwork involved in securing SBA loan guarantees. Additionally, the Department of Energy and the Small Business Administration created a workgroup to serve as a liaison among domestic crude oil producers, banks and financial institutions, and federal small business assistance agencies. It will provide administrative and technical support to banks and financial institutions assisting domestic crude oil producers and it will identify regulatory and legislative initiatives to make SBA loan guarantee programs more useful to small businesses in the domestic crude oil production industry.

Emergency Oil and Gas Loan Guarantee Program – Congress has created a $500 million loan guarantee program for independent producers and small business service companies. The program will provide qualified producers and service industries companies access to a guarantee fund to back loans through the private market. The two-year program calls for a special loan guarantee board, comprised of the Federal Reserve chairman, the Commerce secretary and the Securities and Exchange Commission chairman, to oversee the program. The board would have the flexibility in terms of setting the level of the federal guarantee (up to 85 percent), the appropriate collateral and the loan amounts and interest rates. Small producers and service companies will be able to borrow up to $10 million at a rate determined to be reasonable taking into account the current average yield on outstanding obligations of the United States with remaining periods of maturity comparable to the maturity of the loan. The federal government would not actually provide the loans, but instead guarantee lenders that the government would repay loans if the borrowers defaulted. Regulations implementing the program were released on October 18, 1999. The first loan guarantee applications were submitted, but the regulatory burden of the process and poorly structured criteria have resulted in a low number of initial applications. The Board is now processing these applications.

If this program is going to meet its objectives and respond to the needs of small producers and small business service companies, it needs to be revamped administratively or legislatively. Without changes it will not attract lending industry participation and it will discourage the companies that could benefit from its use.

PADDIE MAC – Another option for Congressional consideration is the PADDIE MAC approach. It would create a government-sponsored enterprise (GSE) along the lines of Freddie Mac and Fannie Mae that would provide low cost capital to support oil and natural gas exploration and production by smaller domestic producers. The nation must face the reality that the 60 percent of domestic oil production that comes from the onshore lower 48 states is rapidly becoming the domain of independents. In 1997, over 60 percent of this production came from non-major oil companies. These companies need reliable financing and the current banking system does not encourage lending to such entities particularly during and after price crises. PADDIE MAC would provide encouragement to develop financing and allow the risk of the financing to be spread among many lending institutions. And, like other successful GSEs, it would create a secondary market that would allow the initial capital to recycle back to fund additional production.

January 2000

Last revised: 05/04/00

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Inactive Well Recovery Act

U.S. Representative Mac Thornberry (R-TX) and Senator Kay Bailey Hutchison introduced legislation (HR 497; S 325) that would help reduce the United States' dependence on foreign oil and increase jobs and production for domestic oil and gas. This will be accomplished by providing producers with a federal income tax exemption for bringing back wells into production that have been shutdown during the oil price crisis – also known as inactive wells.

Reasons for Change

1. ***To provide an Incentive for Recovery*** – The majority of inactive wells have been idled because they became uneconomic during the oil price crisis of 1998-99. This legislation will restore the economic incentive for producers to bring inactive wells back on line by letting them keep the part of their revenues that would otherwise go to pay federal income taxes.
2. ***To Expand Federal Revenues*** – The Inactive Well Recovery Act would increase the stream of revenue going into the federal government in two important ways. First, royalty owners will still pay federal taxes on income generated from the recovered well. Since these individuals are currently paying no taxes on these wells at all, every dollar of additional revenue will be a net gain. Secondly, because the legislation is expected to increase the number of jobs in the oil and gas industry, it will increase the number of workers who will be paying taxes on their wages and earnings.
3. ***To Maintain a Viable Domestic Oil and Gas Industry*** – The facts speak for themselves. In 1981, there were more than 3,900 rotary drilling rigs active in the United States. By 1999, the annual average count had dropped to 625. Likewise, in 1981 nearly 700,000 people were employed in the upstream part of the oil and gas industry. By 1997, this employment had dropped to 335,000 jobs. The oil price crisis of 1998 and 1999 reduced employment by another 65,000. Total job losses during this 18 year period has exceeded 400,000.

To Reduce U.S. Dependence on Foreign Oil Imports – In 1981, the United States imported just under 4.4 million barrels per day of crude oil. By 1998, crude oil imports had increased to over 8.5 million barrels per day. Oil imports exceeded 55 percent of demand in 1998. And, the federal government has again concluded that oil imports pose a threat to national security. Oil imports constitute one of the largest components of the nation's imports and are a significant factor in the country's trade deficit. It also costs us in another important way – national defense. Protecting against the potential instability of Middle Eastern oil supplies consumes significant amounts of the U.S. budget. CNN reported in 1998 that "military buildups that have kept U.S. ships, planes, and troops within striking distance of Iraq since the 1991 Persian Gulf war have cost U.S. taxpayers about $6.8 billion...." This $6.8 billion figure is in addition to annual expenditures of about $50 billion to maintain a strong military contingent in the Gulf. The Inactive Well Recovery Act won't solve all of the country's problems in this regard; it will be a step in the right direction.

This bill was modeled after the three-year inactive well incentive program that was enacted in Texas in 1993. Since that time, nine other states have adopted a similar program. According to then-Texas Railroad Commissioner Barry Williamson, Texas realized more than $1.65 billion in revenue from 6,071 wells returned to production under the state program.

May 2000

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Supporting A Fair Rule for Calculating Federal Royalties

MMS' Proposed Rule on Oil Valuation. On March 18, 2000, MMS changed the rules that set forth the criteria for paying royalties on federal oil production. MMS' proposals essentially increase the amount of royalties to be paid by assessing royalties on downstream values without full consideration of all costs.

On December 30, 1999, the MMS issued its latest proposal. During the 1st Session of the 106th Congress, another moratorium was signed into law prohibiting the MMS from issuing a final rulemaking prior to March 15, 2000. Originally the moratorium would have prohibited MMS from issuing a final rulemaking until October 1, 2000. However, during negotiations between appropriators and the Administration, this shorter timeframe was agreed to because the Administration threatened a veto of the entire budget should it contain a moratorium thereby allowing MMS to issue a final rulemaking on March 16 with an effective date of June 1, 2000.

This proposal contains some positive modifications. For example, except for the newly minted duty to market, MMS has added more certainty for those producers selling oil arm's-length at the lease. When this rulemaking began, all producers including wellhead sellers were to base royalties using NYMEX. Considerable progress has been made in this area. Another area that has been improved is the ability to receive a binding determination as to how to properly pay royalties. The proposal also provides an opportunity to receive guidance, unless MMS disagrees with the factual situation. Improvements have been made in the area of quality adjustments and transportation for those producers who are required to use index.

Unfortunately, no improvements have been made for those producers using an affiliate to market their oil or refine their oil with regard to the starting point for determining value for royalty purposes. Except for the Rockies (excluding New Mexico), the MMS continues to ignore willing buyer/willing seller transactions in the field by proposing published indexes.

The MMS continues to claim that it is legally authorized to require producers to market production downstream at no cost to government.

Royalty Litigation. On March 15, 2000, MMS issued a final oil valuation proposal. During the 1st Session of the 106th Congress, another moratorium was signed into law prohibiting the MMS from issuing a final rulemaking prior to March 15, 2000. The rulemaking became effective June 1, 2000.

On March 28, 2000 IPAA obtained a landmark royalty court decision in *IPAA v. Armstrong.* The judge clearly ruled against MMS by stating that royalties are due on the value of production at the well. He determined that MMS' gas transportation rule was arbitrary and capricious and thereby ordered that it could not be implemented. The government has responded by asking the judge to clarify his decision so it can implement parts of its rulemaking. In conjunction with API, IPAA has filed a motion objecting to the government's request.

This win led to an expedited filing on the oil valuation rulemaking. On April 10, 2000, IPAA filed a lawsuit, *IPAA v. Baca,* claiming that this rulemaking is arbitrary and capricious as well. Fortunately, IPAA was assigned the same judge who decided *IPAA v. Armstrong.* In response to these two lawsuits, Democrats from Texas and a group of Senators have sent letters to Secretary Babbitt requesting the oil valuation rule not be implemented until *IPAA v. Baca* is decided. IPAA's oil royalty litigation task force is currently deciding if IPAA should file a stay with regard to the oil royalty rulemaking or to approach the government and see if it will agree to an expedited hearing schedule.

ACTION

It is likely the government will appeal *IPAA. v. Armstrong.* If so, the Land and Royalty Committee is seeking approval from the Board to respond to this appeal on behalf of the association. Additionally, IPAA is discussing a possible expedited hearing with MMS in regard to IPAA v. Baca.

Royalty In-kind. IPAA continues to pursue royalty in-kind as an alternative to royalty payments. IPAA strongly supports MMS' efforts to maximize and internalize royalty in-kind via pilots. IPAA supports targeted royalty in-kind legislation that would provide MMS additional tools to be more creative when marketing in-kind barrels. This "tool kit" legislation may be included in a more comprehensive energy-related legislative package.

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Support DOI Cost-Cutting and Land Access Measures

During this election year, the Independent Petroleum Association of America has focused its agenda on legislative and regulatory items that are achievable.

Royalties:

The IPAA will remain advocates for reduced royalties during low oil and gas prices, as well as marginal gas wells. However, given the current political climate, any royalty investment program will need to be pursued administratively.

Cost Cutting Legislative Measures:

Bingaman Legislation: The IPAA supports Senator Bingaman's bill, S. 1997 that eliminates the federal government's ability to deduct from federal oil and gas royalty dollars sent to the states a portion of its costs. This bill will properly recognize the role of states with regard to federal land and return more revenues to states IPAA members reside in, dollars that typically go to education.

Murkowski Legislation: The IPAA strongly supports the following components of a comprehensive energy bill led by Senator Murkowski.

1. *Speed up the processing of permits and applications to operate on public lands*: Independents can't afford to have investment capital sitting idle while they wait for overdue approvals.
2. *Streamline processes related to the National Environment Policy Act (NEPA)*: Advocate appropriate funding for BLM so they can more timely and comprehensively conduct environmental document updates.
3. *Delegation to States:* Wherever possible, delegate federal oil and gas activities to willing states. Such delegation eliminates costly and timely duplication between federal and state governments.
4. *Have the DOI and/or DOE conduct an inventory of its oil and gas resources contained in the Rockies:* This inventory would accurately reflect the lands that are not available for development because it hasn't been leased, it has been administratively withdrawn, or it has been leased but contains stipulations that are so restrictive economic development is not feasible. This land inventory may be included in some other legislative vehicle.

Regulatory Initiatives

1. *Promote timely development of coalbed methane in the Powder River Basin*: IPAA will actively pursue needed appropriations to ensure environmental documents and corresponding drilling permits are conducted in a timely fashion.

2. *Forest Service Regulations*: IPAA will comment aggressively on all regulations and environmental documents that are being issued by the Department of Interior Forest Service, for example the road less regulation, which greatly restrict land access. These activities will be closely coordinated with lead regional and state associations. Litigation options regarding the proposed roadless policy are being investigated.
3. *BLM Plain English Rule*: Continue to participate in efforts to ensure that BLM doesn't issue a plain English re-write of all of its oil and gas regulations increases costs or uncertainty for producers. Additionally, IPAA is concerned about BLM's desire to rewrite its offshore oil and gas lease form.

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Internal Revenue Code Section 29 Tax Credit Availability

Section 29 of the Internal Revenue Code provides a tax credit for production of certain nonconventional fuels including gas from coal seams, Devonian shales, and tight formations if produced and sold before Dec. 31, 2002 from a well drilled before 1993. The tax credit currently set at $1.00/Mcf, reduces the regular tax liability dollar-for-dollar and expires Dec. 31, 2002.

Section 29(c)(2)(A) provides that the determination of whether any gas is produced from coal seams, or a tight formation shall be made in accordance with Section 503 of the National Gas Policy Act of 1978 (NGPA). Under this provision, the Federal Energy Regulatory Commission (FERC) reviewed well determinations that were made by state jurisdictional agencies. The FERC review was not a condition precedent to the qualification of the well's production, but could be obtained retroactively. The Natural Gas Wellhead Decontrol Act of 1989 repealed section 503 of the NGPA. This resulted in FERC's determination that it lacked authority to review state determinations under Section 29.

In an effort to accommodate congressional intent, FERC extended its review process to May 1994 for determination requests filed before 1993. The IRS previous position in Rev. Rul. 93-54 found the drilling requirements to qualify for a section 29 credit were met if a taxpayer recompletes into a qualifying formation from a well-bore that was drilled before 1993 and produced from a deeper formation. However, at odds with this previous ruling and clear congressional intent is a judgment in the *True Oil v. Commissioner of Internal Revenue* case that a FERC determination is a prerequisite for a section 29 well determination.

On February 8, 2000, FERC proposed a rule to allow for determinations on well recompletions commenced after January 1, 1993, which comply with Rev. Rul. 93-54. IPAA filed comments with FERC in April 2000 urging expansion of its proposal to include all wells that would qualify under the scope of Section 29.

On July 14 FERC issued a final rule reinstating provisions for well category determinations for certain categories of high-cost gas under NGPA section 107 (Order No. 616). An NGPA determination will allow the gas to be eligible for a tax credit under section 29 of the Internal Revenue Code. The final rule adopts the IPAA position and extends the provisions to all wells spudded before January 1, 1993, and recompletions both before and after that date that could qualify for the section 29 tax credit. The rule also provides for the designation of new tight formations.

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Fact Sheet

Offshore Development

Each year, independents dramatically increase their presence in the offshore, in both traditional production areas and in frontier deepwater leases. More than 400 independents are active in the Gulf of Mexico, with at least 60 independents participating in the development of deepwater leases. Independents are buying the vast majority of leases at sales in the Gulf of Mexico.

Summary

When oil experienced a price crisis, the IPAA responded by advocating legislation that would provide for royalty incentives in different forms. Given the recovery of prices, efforts regarding royalty incentives have been redirected to administrative options. Offshore producers believe that marginal producing properties are being abandoned prematurely and marginal fields are being left behind. A royalty incentive program may encourage development of these properties. Additionally, independents believe new leases to be offered in deep and ultra-deep waters could benefit from royalty increases.

IPAA is addressing several potential legislative issues including monitoring MMS' new proposed offshore lease form, DOI's attempt to deem an oil and gas lease not to be a property interest, the impact of essential fish habitat designations, the fairness of an ocean policy act, sufficient appropriations for MMS to ensure timely lease and permit issuance, offshore impact assistance legislation, and offshore moratoria. Regulatory issues include MMS regulations and US Coast Guard rewrites, safety and disqualification of operators, blowout prevention procedures, and discharge permits.

Highlights of Priority Issues

1. **Royalty Incentives for Offshore Properties.** IPAA is working with an industry coalition and DOI/DOE to attempt to model the economic impact of offering royalty incentives for offshore marginal well and marginal fields not yet developed, up to deepwaters. Depending on the results of these modeling exercises, IPAA may seek implementation of these incentives via a rulemaking.

   Other royalty incentive efforts include participation in three other industry workgroups. One of the workgroups is modeling royalty incentives for ultra-deepwaters, which could be offered as part of the lease sale. The second workgroup is making recommendations as to how MMS may streamline its case-by-case application process for deepwater leases that existed prior to November 1985. The third workgroup is modeling the

   economic need for a continuation of royalty incentives for properties in deepwaters (200 m – 1600 m). This modeling effort has taken two forms:

1. A collaborative effort with MMS, and
2. A third party effort.

2. Maintain access to the potential resource areas in the offshore, with a focus on Sale 181. Bills have been introduced each Congress that would place under permanent moratorium all offshore areas currently closed to leasing (which accounts for 86% of the U.S. offshore). Offshore oil and natural gas production has established an exemplary record of safe, environmentally sound operations. Vice-President Gore recently announced a permanent moratorium for drilling offshore Florida and California. IPAA has made Sale 181 in the eastern Gulf of Mexico a priority. It would be the first sale held in the eastern Gulf for a number of years and is scheduled for late 2001.

3. **DOI's Attempt to Deem a Federal Lease not to be a Property Interest.** During the 105th and 106th Congress, DOI attempted to insert into Bankruptcy Reform Legislation, a provision that would deem a federal lease not to be a property interest. Its stated goal was to give the department quicker access to the property during a bankruptcy proceeding. The lending community quickly pointed out that such a provision would have a chilling affect on capital made available to producers for development. This consequence is unacceptable and would result in fewer wells being drilled. IPAA is encouraging an alternative approach for dealing with DOI's concerns with abandoned properties.
4. **Critical Fish Habitats.** IPAA is concerned about the Department of Commerce issuing final regulations that could place off limits oil and gas development in areas of the offshore deemed to be an essential fish habitat. Final regulations may be proceeding that don't recognize the fact that offshore oil and gas operations can coexist in a safe and sound manner in areas containing fish habitats. If the Commerce Department begins to limit access to the offshore, congressional action may be necessary.
5. **Coast Guard Regulations.** IPAA is concerned about a proposed major revision of Coast Guard regulations affecting Outer Continental Shelf (OCS) activities. The revision intends to address new developments in the offshore industry and to implement existing legislation and interagency agreements. Many of the proposed changes would have a substantial cost impact on independent producers operating in the OCS. IPAA is working with an industry coalition to outline the substantial monetary impact the proposal will have on the offshore oil and gas industry. The coalition, which has asked the Coast Guard to extend the comment due date, is currently working to develop comments and related material.
6. **New Fees for Offshore Operations.** As part of the President's FY 2001 Budget, the Administration is proposing new fees to the tune of $10 million/or various applications to offset budget reductions. IPAA opposed this new assessment and will seek the appropriate level of appropriations so MMS can perform its duties without assessing fees.

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FACT SHEET

Role of the Strategic Petroleum Reserve

The Strategic Petroleum Reserve (SPR) is the nation's first line of defense against an interruption in petroleum supplies. The U.S. government's commitment to withdraw petroleum from the SPR early in a potential supply emergency makes the 570 million-barrel reserve a significant deterrent to petroleum import cutoffs and a key tool of U.S. foreign policy.

Market driven price increases for petroleum and petroleum products have recently led some lawmakers and consumer groups to call for the sale of petroleum from the SPR to lower prices. IPAA strongly opposes all non-emergency sales of crude oil from the SPR aimed at manipulating prices.

The SPR was created to deal with supply disruptions, not high prices. Interference in the petroleum market is counterproductive to natural adjustments in the marketplace, and is particularly harmful to America's independent producers. Because they operate in the upstream, independent producers are more susceptible to shifts in the commodity market prices of petroleum.

Each day nearly 19 million barrels of petroleum are used throughout the U.S., principally as transportation fuels. This constitutes nearly 30 percent of daily world production. With increasing U.S. consumption, petroleum imports have likewise increased significantly. Currently, the U.S. depends on imports to meet 56 percent of its petroleum requirements, and this dependence is expected to increase to over 62 percent by the year 2010.

Two thirds of the petroleum entering the world market is from historically unstable countries in the Middle East and Africa. During a petroleum supply disruption, however, conventional supply patterns may be disrupted. As a result, with its high level of import dependence, the U.S. is potentially at considerable risk from supply disruptions in any part of the world.

If petroleum were sold from the SPR each time fuel prices rose, we would reduce our ability to address a situation with the potential to seriously injure the U.S. economy. In addition, a drawdown of the reserve might not have the desired result. Consider this summer's high gasoline prices. Prices have risen because increased demand has outpaced supplies of gasoline. A drawdown of petroleum from the SPR would not have the intended impact on gasoline prices because it would take weeks to release the petroleum from the reserve, refine it into gasoline and deliver it to market. In addition, refineries are already operating at peak capacity (96 percent), and are not able to increase production of gasoline.

With more than two thirds of petroleum exports to the world market being supplied from politically volatile countries, the existence of the SPR is more important now than ever. Any sale of petroleum from the SPR when supplies are adequate to meet domestic needs could easily undermine the petroleum markets and drive the domestic industry, especially independent producers, back into economic turmoil.

IPAA urges policy makers to oppose all non-emergency sales of SPR stockpiles to manipulate petroleum markets, and to support polices that will strengthen not only the SPR but American's true "strategic petroleum reserve"—independent petroleum producers.

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Marginal Well Tax Credit

Summary of Legislation

The Marginal Well Production Tax Credit amendment to the Internal Revenue code will establish a tax credit for existing marginal wells. Marginal oil wells are those with average production of not more than 15 barrels per day, those producing heavy oil, or those wells producing not less than 95 percent water with average production of not more than 25 barrels per day of oil. Marginal gas wells are those producing not more than 90 Mcf a day. The amendment will allow a $3 a barrel tax credit for the first 3 barrels of daily production from an existing marginal oil well and a $0.50 per Mcf tax credit for the first 18 Mcf of daily natural gas production from a marginal well.

The tax credit would be phased in and out in equal increments as prices for oil and natural gas fall and rise. Prices triggering the tax credit are based on the annual average wellhead price for all domestic crude oil and the annual average wellhead price per 1,000 cubic feet for all domestic natural gas. The credit for the current taxable year is based on the average price from the previous year. The phase in/out prices are as follows:

OIL – phase in/out between $14 and $17

GAS – phase in/out between $1.56 and $1.89

The amendment would allow the tax credit to be offset against regular and the alternative minimum tax (AMT). In addition, for producers without taxable income for the current tax year, the amendment would provide a 10-year carryback provision allowing producers to claim the credit on taxes paid in those years. The carryback credit may be used to offset regular tax and AMT.

Actions Taken

When oil prices fell below $14.00 per barrel in March 1998, IPAA initiated efforts to develop a marginal well tax credit bill based on legislation that had been introduced in previous Congresses and consistent with the recommendations of the National Petroleum Council's *Marginal Wells* report in 1994. This legislation was introduced April in the House by Representative Wes Watkins (R-OK) and in the Senate primarily by Senator Kay Bailey Hutchison (R-TX). During the remainder of the 105th Congress, IPAA pressed for passage of this legislation. A letter from IPAA and NSWA leadership was sent to President Clinton. Meetings were held with the Department of Energy to discuss the importance of the tax credit. In July 1998, IPAA sponsored a call-up of members to press for action on the tax credit if tax legislation was considered during this Congress.

The Dept. of Energy has evaluated the benefits of a bill and believes that it could prevent the loss of 140,000 barrels per day of production if fully employed during times of low oil prices. Energy Secretary Bill Richardson wrote to Treasury Secretary Robert Rubin expressing his support for the proposal and seeking a coordinated effort with the Treasury Dept. In November and December 1998, IPAA met with members of Energy Secretary Richardson's emergency task force urging action on Administration support for a marginal wells tax credit bill.

As the 106th Congress convened the bill was introduced in the House of Representatives by Rep. Wes Watkins with 12 original cosponsors as HR 53. In the Senate, the bill was introduced as a part of a larger bill (S. 325) by Sen. Kay Bailey Hutchison with 18 cosponsors. It was also included in other tax legislation addressing oil and gas production tax reform. IPAA testified before the Senate Energy and Natural Resources Committee, the House Committee on Commerce, and the House Ways and Means Committee regarding the need for tax reform, including the marginal wells tax credit. When the Department of Commerce initiated its Section 232 analysis under the Trade Expansion Act, IPAA urged consideration of a marginal wells tax credit as a component of a tax reform package. The Taxpayer Refund And Relief Act Of 1999 did not create any new tax credits and therefore did not include a marginal wells tax credit in the package of oil and gas tax reform measures in that bill.

In March, President Clinton stated his support for tax reforms to allow expensing of geological and geophysical costs and for delay rental payments. He also stated that the Administration was continuing to evaluate alternatives to maintain the nation's marginal well production. Subsequently, Sen. Kay Bailey Hutchison and 8 cosponsors introduced S. 2265 which includes the marginal wells tax credit, the expensing of G&G costs, and the expensing of delay rental payments. It has also been included in S.2557 and HR 4805, comprehensive energy policy bills. Congress, in response to the high oil prices of the past winter, continues to consider a legislative response, including tax reforms.

As Congress continues to evaluate tax reforms for the oil and gas production industry, IPAA will continue to advocate a marginal wells tax credit as a component of those reforms.

August 2000

Last revised: 08/02/00

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ipaa America's Oil and Gas Producers

Fact Sheet

Regulatory Relief

The petroleum and natural gas exploration and production (E&P) industry is highly regulated by both state and federal governments. Taken together, these regulations add costs to the production of domestic petroleum and natural gas. The government needs to reduce or eliminate unnecessary regulations. As the 1998-99 low petroleum price crisis demonstrated, both state and federal governments need to act to reduce regulatory costs on domestic production. Moreover, in general, since U.S. production is already some of the world's highest cost production, it is essential to minimize regulatory costs to enhance and maintain domestic production, not only of petroleum but clean burning natural gas as well. The federal government is a pervasive factor at all levels.

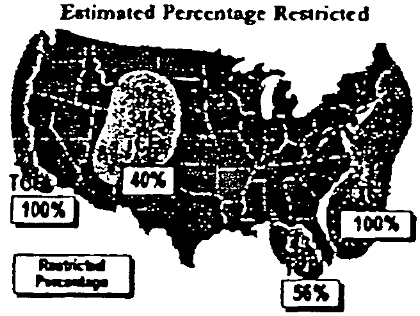
For example, while state governments impose most direct environmental controls, overarching federal standards or pressure drives these actions. Currently, for example, EPA has initiated an effort to address the Total Maximum Daily Load (TMDL) of pollutants on U.S. water bodies. While this is intended to address major discharges of contaminants, it can result in inadvertent requirements on the E&P industry if it excludes the major contributors. Similarly, new EPA regulations will reduce the size of facilities that are subject to new stormwater construction permitting requirements. While EPA argues that these will not the burdensome requirements, they have not yet been applied. These types of actions must be carefully written to eliminate excessive costs and paperwork on E&P operations with no environmental benefit

Similarly, the federal government has pending proposals that need to be ended. For years, EPA has considered applying the Toxic Release Inventory program to the E&P industry – where it was never intended to apply. It would be costly and provide meaningless information. Now is the time for EPA to end this threat. Rather, EPA should look for ways to further simplify the Right-To-Know requirements currently imposed on the E&P industry.

Other EPA issues include action to create inappropriate controls on hydraulic fracturing and new regional haze regulations. As a result of a contrived interpretation of the federal underground injection control (UIC) program in the *LEAF v. EPA* case, EPA has now required regulations in Alabama that compel the use of federally certified drinking water in hydraulic fracturing in coal bed methane operations. However, LEAF has instituted another case that could result in the national application of these or more burdensome regulations on an environmentally benign activity. At a time when the nation needs to develop its domestic natural gas resources – development that will hinge on the use of hydraulic fracturing – Congress needs to confirm the longstanding intent of the Safe Drinking Water Act that it is not intended to regulate petroleum and gas E&P drilling operations.

The federal government has an even greater influence on E&P operations on federal land where it sets all the conditions. Here, the Department of Interior has recognized that it can act. DOI extended lease periods to reflect the 1998-99 price crisis. But, more can be done. IPAA has identified a specific list of action steps that should be undertaken regulatory or legislatively, if necessary. These are promoting the timely development of coalbed methane resources, transferring federal responsibilities to states, royalty relief for marginal offshore and onshore properties, improving the NEPA process, and obtaining an accurate inventory of government controlled petroleum and gas resources. These actions should be taken regardless of price to increase domestic supply.

Resource Estimates - Restricted Areas
Estimated Percentage Restricted



More importantly, in order to meet the country's energy needs, government controlled land production must dramatically increase. The National Petroleum Council *Natural Gas* Study identified access to the national resource base as a key factor in meeting the future demand for this energy source. Much of the onshore natural gas resource base is located in the Rocky Mountains where federal policy limits access to an estimated 137 trillion cubic feet of natural gas. The constraints differ. Monument and wilderness designations prohibit access. Regulations like the Forest Service roadless policy and prohibitions in the Lewis and Clark National Forest are equally absolute. At the same time the permitting process to explore and develop resources can work to effectively prohibit access. These constraints range from federal agencies delaying permits to revise environmental impact statements to habitat management plans overlaying one another to prohibit activity to unreasonable permit requirements that prevent production. There is no single solution to these constraints. What is required is a commitment to develop these access policies with a full recognition of the importance of developing the natural gas resource. A good first step is an inventory of resources under federal lands to determine where potential conflicts might exist rather than continue the current abstract debate.

Unfortunately, much of the natural gas production debate will rage over allegations of environmental risk. It should not be an issue. As stated in the Department of Energy's *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology publication*, "Resources underlying arctic regions, coastal and deep offshore waters, sensitive wetlands and wildlife habitats, public lands, and even cities and airports can now be contacted and produced without disrupting surface features above them. Wildlife preserves and conservation easements are created and managed jointly by industry, environmental, and government stakeholders. In Alaska, such new approaches as ice pads and roads, multilateral completions, and annular injection of drilling wastes minimize environmental impacts while also reducing costs."

Taken together, federal regulatory actions can further burden the development of clean burning natural gas essential to meet future energy needs and worsen the national dependency on foreign petroleum. In the national interest, regulatory restraint and relief is essential.

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NHA National Hydropower Association

hydro facts

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Facts You Should Know About Hydropower

Hydropower is a clean, renewable and reliable energy source that serves national environmental and energy policy objectives. Hydropower converts kinetic energy from falling water into electricity without consuming more water than is produced by nature.

Since 1880, when 16 brush-arc lamps were powered using a water turbine at the Wolverine Chair Factory in Grand Rapids, MI, hydropower has played a vital role in the U.S. energy mix. Here are some facts about hydropower:

Hydropower—A Major Source of Energy ▲

- The United States is one of the largest producers of hydropower in the world, second only to Canada.
- Currently, hydropower ranges between 10 and 12 percent of U.S. electrical generation or enough electricity to supply the 37.8 million homes in California, Texas, New York, Pennsylvania, Ohio, and North Carolina.
- In the Pacific Northwest, up to 70 percent of electricity is generated from hydropower.
- Of the 75,187 existing dams in the U.S., less than 3 percent are used for hydroelectric generation.
- Non-federal, licensed conventional hydroelectric capacity equals 40.0 Gigawatts (GW) at 2,162 sites in the U.S. The federal government owns another 8.2 GW at 165 sites. Total U.S. hydroelectric capacity is 103.8 GW when you pumped storage.
- Throughout the world, about one-fifth of electricity is generated from hydropower.

Hydropower—Clean and Renewable ▲

- In 1998, hydropower avoided the release of an additional 75.8 million metric tons of carbon equivalent into the atmosphere. Without hydropower, the U.S. would have to burn an additional 126 million tons of coal, plus 25 million barrels of oil, and 452 billion cubic feet of natural gas combined.

- By generating carbon-free electricity, hydropower avoids burning fossil fuels and releasing an amount of carbon dioxide that equals the annual exhaust of 61 million passenger cars or half of the cars on U.S. roads.
- Like wind, solar, geothermal and biomass, hydropower is a renewable source of electricity. Water, its "fuel", is essentially infinite, replenished by the hydrologic cycle, which is powered by the sun.
- Hydropower is the nation's leading renewable energy source. It accounts for 81 percent of the nation's total renewable electricity generation.

Hydropower—A Sound Environmental Choice ▲

- Hydroelectric projects can enhance wetlands and support healthy fisheries. Wildlife preserves can be created around reservoirs, which, in some cases, provide stable habitats for endangered or threatened species.
- A recent U.S. resource assessment shows there are 29.8 GW of potential hydropower capacity at 5,677 sites that have been screened for favorable environmental, legal and institutional conditions. Seventy two percent of this potential—21.3 GW—can be developed without the construction of a new dam.
- Of the 765 hydro projects licensed by the federal government during the 1980's, 91 percent did not involve the construction of a new dam.
- There were a total of 81 million recreation user days provided at FERC licensed hydropower projects in 1996. Boating, skiing, camping, picnic areas and boat launch facilities are all supported by hydropower.

Hydropower—Reliable, Efficient and Secure ▲

- Today's hydropower turbines are capable of converting 90 percent of available energy into electricity—that is more efficient than any other form of generation. Even the best fossil fuel power plant is only about 50 percent efficient.
- The efficiency of hydropower, while impressive, can be further improved simply by refurbishing existing equipment. Increasing the efficiency of hydropower machinery in the existing system by only one percent would increase the United States' annual generation of electricity by about 3.3 billion kilowatt-hours, supplying more than 300,000 households.
- Hydropower's operational flexibility—its unique ability to change output quickly—is highly valued, and will become even more so in a deregulated market. Its unique voltage control, load-following and peaking capabilities help maintain the stability of the electric grid ensuring economic growth and a high quality of life.
- Hydroelectricity adds to our national security. Water from rivers is a purely domestic resource that is not subject to disruptions from foreign suppliers, production strikes or transportation issues.

▲ back to top

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Photo courtesy of the Pacific Gas and Electric Company.

Release (36)

INGAA Energy Policy Issues

The Interstate Natural Gas Association of America (INGAA) is the trade association that represents interstate natural gas pipelines in the United States, the inter-provincial pipelines in Canada and PEMEX in Mexico. INGAA's member company pipeline systems transport 90 percent of the natural gas consumer in the United States. Natural gas provides 25 percent of the energy consumed in the United States. EIA and others have predicted that demand for natural gas will increase from 22.7 Trillion cubic feet (Tcf) per year today to 30 Tcf in approximately 2010. To meet this demand, there needs to be an increase in natural gas supply and infrastructure. INGAA believes any national energy policy should seek market-based solutions to meet growing demand. Following are the issues that INGAA would like to see addressed administratively or through legislation as Washington formulates an energy policy.

1. Create a Forum to Address Energy Policy Matters

In the past, although the Department of Energy had sought to have input on the impact on energy supply or development that many administrative regulations issued by other departments and agencies can have, these departments and agencies often ignored DOE's input. INGAA urges the Administration and/or legislation to create a forum that will require departments and agencies to take into account actions and regulations that would affect energy supply and infrastructure. This could be done in a number of ways. A proposal similar to the Small Business Regulatory Enforcement Fairness Act is one approach. Forming a group in the Executive Office of the President (perhaps similar to CEQ) to moderate disputes among agencies, investigate undue delays in projects and act as a liaison between the federal government and states is another.

2. Improve Permitting Processes and Interagency Coordination

The Council on Environmental Quality should be required by the Administration or legislation to review NEPA and the resulting process to seek ways to reduce the NEPA review and permitting time.

> For example, CEQ, with FERC, should form an interagency task force to develop an interagency memorandum of understanding to expedite the environmental review and permitting of interstate natural gas pipelines. This would provide a means to address the process on an industry-wide basis, rather than address permitting coordination on individual projects.

3. Expand Access to Develop Natural Gas Supplies and Infrastructure

The third issue supported by INGAA is to obtain additional supplies of natural gas and have access to federal lands for both additional supply and to build the necessary pipeline infrastructure. Actions that can be taken include:

A. INGAA supports expedited approval of a natural gas pipeline from Alaska to bring natural gas to the lower 48 states. Completion of this project is expected to take from 5 to 7 years.

B. INGAA also supports obtaining access to lands that are either restricted or off limits in the Rocky Mountains and the Atlantic and Pacific coasts for new gas supplies and/or infrastructure.

C. Pipeline Safety legislation (which should not be included in energy policy legislation) should have performance goals, not prescriptive requirements. The Senate amendment that requires all integrity inspections to be completed within a five-year period can cause natural gas deliveries to be reduced in times of high demand. There is not a technical basis for that frequency. Analysis prepared for INGAA shows that conservatively the appropriate frequency is more in the range of fifteen years. Hydrostatic testing requires pipelines to be shut down for a period of time and use of smart pigs causes a reduction in flow. If an arbitrary date, such as five years, is required, pipelines will have to do these tests often during periods of high natural gas demand, reducing our ability to deliver natural gas to our customers. Except in emergencies, we traditionally do these tests during times (such as spring and fall) when the demand for natural gas is reduced.

D. INGAA supports a FERC study of the impediments that delay the environmental review, data gathering, certification and construction of interstate natural gas pipeline projects. This study should consider the approvals and permits from other federal departments and agencies as well as from state and local agencies.

E. INGAA is concerned about possible changes to value rights-of-way (ROW) that are under the jurisdiction of BLM, the U.S. Forest Service, the Bureau of Indian Affairs, etc. For example, BLM is considering changing the way they charge for their ROW for fiber optics from a one-time charge to a volumetric approach. This could set a precedent that would be imposed on natural gas pipelines. There should also be a study of the present rights-of-way across federal lands to determine the feasibility of their use as right-of-way for new pipeline or other transmission capacity.

F. INGAA opposes state efforts to designate interstate pipelines that are in service or capable of being in service as eligible to be listed as historic under the National Historic Preservation Act. This, at best, causes unnecessary delays of repair and maintenance on older pipelines.

G. INGAA supports expansion and extension of Section 29 tax credits to encourage development of new and unique sources of energy. In 1999 4.87 Tcf of came from non-conventional resources resulting from Section 29 tax credits. This is 26 percent of the natural gas produced in the lower 48 states.

H. INGAA supports a seven-year depreciation period for gathering lines.

I. INGAA encourages the Administration to review of the U.S. Forest Service rulemaking regarding roadless areas and the recent designations of National Monuments regarding their impact on energy production and transmission.

4. Support R&D

Finally, INGAA supports establishment of an R&D effort between DOE and OPS to develop improved and new technologies to better assess pipeline safety.

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TABLE 1
Installed Generating Capacity in the United States
Megawatts (Nameplate)

At December 31st	Investor-Owned Utilities	Government and Cooperatives	Total Electric Utility Industry	Non Utility Sources	Total United States
1979.	464,144	134,299	598,443	17,436	615,879
1980.	477,083	136,612	613,695	17,323e	631,018
1981.	490,767	144,041	634,808	17,142e	651,950
1982.	499,111	150,994	650,105	16,938e	667,043
1983.	505,487	152,695	658,182	16,765e	674,947
1984.	514,863	157,600	672,462	17,371e	689,833
1985.	530,405	158,328	688,733	22,920	711,653
1986.	544,199	163,485	707,684	25,321	733,005
1987.	552,795	165,261	718,056	30,015	748,071
1988.	557,756	166,097	723,852	33,741	757,593
1989.	562,127	168,757	730,883	40,267	771,150
1990.	568,769	166,282	735,051	45,127	780,178
1991.	573,023	166,934	739,957	50,052	790,009
1992.	572,920	168,730	741,651	55,188	796,839
1993.	575,163	169,526	744,689	58,134	802,823
1994.	574,834	171,120	745,954	65,010	810,964
1995.	578,668	171,874	750,541	68,416	818,958
1996.	582,214	174,267	756,481	69,328	825,809
1997.	582,508	177,367	759,875	70,301	830,176
1998r.	531,267	196,993	728,259	99,650	827,909
1999p.	483,746	194,209	677,955	167,357	845,312

Note: Total may not equal sum of components due to independent rounding.

p Preliminary. e Estimated. r Revised.

Sources: U.S. Department of Energy. Energy Information Administration. Annual Electric Generator Report (EIA-860A), and Annual Electric Generator Report–Nonutilities (EIA-860B), and Edison Electric Institute's "Capacity and Generation of Non-Utility Sources of Energy."

TABLE 2

Installed Generating Capacity
Total Electric Utility Industry

By Ownership and Type of Prime Mover Driving the Generator

Megawatts (Nameplate)

At December 31st	Total Electric Utility Industry	Investor-Owned Utilities	Cooperatives	Subtotal Government	Municipal Utilities	Federal	Power Districts, State Projects
TOTAL (Capacity of Generators Driven by All Types of Prime Mover)							
1979	598,443	464,144	13,837	120,462	34,525	58,346	27,591
1980	613,695	477,083	15,422	121,190	34,598	59,083	27,509
1981	634,808	490,767	18,406	125,635	35,125	60,982	29,527
1982	650,105	499,111	21,463	129,530	35,819	62,544	31,168
1983	658,182	505,487	22,202	130,493	36,598	62,973	30,923
1984	672,462	514,863	24,738	132,862	36,717	63,304	32,841
1985	688,733	530,405	24,574	133,754	37,017	63,710	33,027
1986	707,684	544,199	26,430	137,055	38,584	63,864	34,607
1987	718,056	552,795	26,359	138,902	39,378	64,666	34,858
1988	723,852	557,756	26,383	139,714	40,388	64,792	34,533
1989	730,883	562,127	26,358	142,399	40,668	67,193	34,537
1990	735,051	568,769	26,337	139,945	40,115	65,434	34,397
1991	739,957	573,023	26,453	140,481	40,424	65,561	34,496
1992	741,651	572,920	26,015	142,715	41,629	66,116	34,970
1993	744,689	575,163	26,107	143,419	41,789	66,129	35,501
1994	745,954	574,834	26,372	144,748	41,992	66,333	36,423
1995	750,541	578,668	27,120	144,754	42,179	65,937	36,838
1996	756,481	582,214	27,195	147,072	43,035	67,151	36,887
1997	759,875	582,508	27,999	149,368	43,762	68,868	36,738
1998r	728,259	531,267	32,523	164,470	50,548	68,652	45,270
1999p	677,955	483,746	34,612	159,597	50,184	68,675	40,738
HYDRO (Capacity of Generators Driven by Water Wheels and Turbines)							
1979	75,351	23,916	67	51,368	4,693	34,495	12,180
1980	76,378	24,227	67	52,084	4,692	35,212	12,180
1981	77,145	24,319	67	52,759	4,686	35,891	12,182
1982	78,128	24,584	81	53,464	4,729	36,378	12,357
1983	78,968	24,977	81	53,910	4,781	36,803	12,326
1984	80,590	26,127	81	54,382	4,850	37,139	12,393
1985	83,015	27,571	104	55,340	5,159	37,631	12,550
1986	85,165	28,949	116	56,100	5,952	37,636	12,512
1987	85,910	29,149	113	56,648	5,401	38,438	12,809
1988	86,886	29,680	169	57,037	5,467	38,713	12,856
1989	87,506	29,651	169	57,685	5,548	39,237	12,900
1990	87,235	29,198	170	57,867	5,588	39,359	12,920
1991	88,693	30,351	169	58,173	5,515	39,487	13,171
1992	89,740	30,525	271	58,943	5,668	40,041	13,234
1993	90,155	30,517	394	59,244	5,723	40,054	13,467
1994	90,330	30,107	394	59,829	5,936	40,259	13,634
1995	91,114	30,236	1,156	59,722	5,938	39,987	13,797
1996	90,952	30,266	1,021	59,666	5,873	39,931	13,861
1997	92,495	30,865	1,318	60,312	6,122	40,438	13,755
1998r	91,156	29,352	989	60,815	5,544	40,695	14,576
1999p	89,800	27,626	1,092	61,083	6,061	40,703	14,318
CONVENTIONAL STEAM+ (Capacity of Generators Driven by Steam Engines and Turbines)							
1979	462,999	392,349	13,375	57,275	25,599	20,378	11,298
1980	475,276	403,031	14,954	57,291	25,697	20,393	11,201
1981	491,287	413,571	17,939	59,778	26,199	20,392	13,187
1982	503,804	420,863	21,011	61,930	27,026	20,246	14,658
1983	507,136	422,944	21,767	62,424	27,737	20,244	14,444
1984	516,537	429,047	24,278	63,212	27,788	20,244	15,181
1985	520,299	433,103	24,098	63,098	27,764	20,177	15,156
1986	524,136	432,601	25,963	65,571	28,495	20,326	16,750
1987	524,286	431,677	25,950	66,659	29,629	20,326	16,704
1988	526,564	432,556	25,916	68,091	30,722	20,177	17,192
1989	529,144	433,140	25,898	70,106	30,896	22,058	17,152
1990	531,147	436,810	25,891	68,447	31,274	20,177	16,995
1991	534,061	439,334	26,013	68,714	31,678	20,177	16,859
1992	534,507	438,878	25,462	70,167	32,720	20,177	17,269
1993	536,873	441,116	25,423	70,333	32,590	20,177	17,565
1994	537,884	441,177	25,685	71,022	32,524	20,177	18,320
1995	541,634	444,807	25,674	71,154	32,730	20,052	18,372
1996	546,625	448,513	25,883	72,229	33,624	20,052	18,553
1997	549,745	449,491	26,363	73,890	34,115	21,265	18,510
1998r	522,111	412,316	28,306	81,490	37,592	20,743	23,155
1999p	476,265	369,001	30,421	76,843	38,553	20,743	19,547

See page 9 for footnotes.

TABLE 2 (continued)

Installed Generating Capacity
Total Electric Utility Industry

By Ownership and Type of Prime Mover Driving the Generator

Megawatts (Nameplate)

At December 31st	Total Electric Utility Industry	Investor-Owned Utilities	Cooperatives	Subtotal Government	Municipal Utilities	Federal	Power Districts, State Projects
NUCLEAR STEAM (Capacity of Generators Driven by Nuclear Reactors)							
1979.	54,593	46,065	50	8,478	963	3,456	4,059
1980.	56,488	47,960	50	8,478	963	3,456	4,059
1981.	60,776	50,992	50	9,734	963	4,677	4,094
1982.	63,042	52,038	50	10,954	963	5,897	4,094
1983.	67,073	56,069	50	10,954	963	5,897	4,094
1984.	70,484	58,380	50	12,054	963	5,897	5,194
1985.	80,397	68,238	50	12,109	963	5,897	5,249
1986.	92,417	80,213	50	12,154	963	5,897	5,294
1987.	101,604	89,450	-	12,154	963	5,897	5,294
1988.	103,397	92,103	-	11,294	963	5,897	4,434
1989.	106,748	95,454	-	11,294	963	5,897	4,434
1990.	107,980	97,649	-	10,331	-	5,897	4,434
1991.	108,443	98,113	-	10,331	-	5,897	4,434
1992.	107,850	97,519	-	10,331	-	5,897	4,434
1993.	107,849	97,518	-	10,331	-	5,897	4,434
1994.	107,857	97,526	-	10,331	-	5,897	4,434
1995	107,896	97,566	-	10,331	-	5,897	4,434
1996.	108,976	97,375	-	11,601	-	7,167	4,434
1997.	107,632	96,032	-	11,601	-	7,167	4,434
1998r.	104,757	84,063	2,932	17,762	3,763	7,205	6,794
1999p.	102,291	81,736	2,800	17,755	3,755	7,205	6,795
INTERNAL COMBUSTION (Capacity of Generators Driven by Internal Combustion Engines)							
1979.	5,500	1,814	345	3,341	3,270	17	54
1980.	5,553	1,865	351	3,337	3,246	22	69
1981.	5,600	1,885	351	3,364	3,278	22	65
1982.	5,131	1,627	321	3,182	3,101	22	60
1983.	4,996	1,494	304	3,198	3,117	22	58
1984.	4,841	1,306	330	3,205	3,115	17	73
1985.	5,001	1,477	322	3,202	3,130	*	72
1986.	5,944	2,420	301	3,224	3,171	-	52
1987.	6,212	2,484	296	3,432	3,381	-	52
1988.	6,999	3,416	298	3,285	3,233	-	52
1989.	7,482	3,880	290	3,311	3,258	1	52
1990.	8,685	5,111	276	3,298	3,250	-	48
1991	8,755	5,223	271	3,261	3,228	-	33
1992.	9,550	5,996	282	3,271	3,238	-	33
1993.	9,807	6,009	289	3,508	3,473	-	36
1994.	9,871	6,021	293	3,557	3,521	-	36
1995	9,885	6,057	290	3,537	3,502	-	36
1996.	9,916	6,058	291	3,567	3,528	-	39
1997.	9,984	6,111	318	3,555	3,516	-	39
1998r.	10,214	5,528	296	4,390	3,637	9	744
1999p.	9,551	5,353	300	3,897	3,803	23	72
WIND++ (Capacity of Generators Driven by Wind Turbines)							
1993.	1	*	*	*	*	*	-
1994.	8	*	*	7	7	*	-
1995	8	*	*	7	7	-	-
1996.	8	*	*	7	7	-	-
1997.	14	6	*	7	7	-	-
1998r.	16	6	*	9	8	-	2
1999p.	44	28	*	16	10	-	6
SOLAR+++ (Capacity of Generators Driven by Photovoltaic and Solar Thermal Energy)							
1993.	4	2	-	2	2	-	-
1994.	5	2	-	3	3	-	-
1995	4	2	-	3	3	-	-
1996.	4	2	-	3	3	-	-
1997.	5	3	-	3	3	-	-
1998r.	5	2	-	4	4	-	-
1999p.	5	2	-	3	3	-	*

Total may not equal sum of components due to independent rounding.
**Less than five hundred kilowatts. p Preliminary. r Revised.*
+Includes Combustion Turbines and Combined Cycle Plants. ++Capacity by wind available as of 1983 in previous Statistical Yearbooks.
+++Capacity by solar available as of 1984 in previous Statistical Yearbooks.
Sources: U.S. Department of Energy. Energy Information Administration. Monthly Power Plant Report (EIA-759) and Annual Electric Power Report (EIA-860A).

TABLE 3

Installed Generating Capacity
Total Electric Utility Industry

By State and Type of Prime Mover Driving the Generator
At December 31st, 1998r and 1999p - Megawattts (Nameplate)

State/Division	Total Electric Utility Industry+ 1999p	1998r	Hydro 1999p	1998r	Conventional Steam ++ 1999p	1998r	Nuclear Steam 1999p	1998r	Internal Combustion 1999p	1998r
Total United States	**677,955**	**728,259**	**89,800**	**91,156**	**476,265**	**522,111**	**102,291**	**104,757**	**9,551**	**10,214**
Maine	90	1,457	34	383	35	1,039	-	-	21	36
New Hampshire	2,426	2,426	65	65	1,118	1,118	1,242	1,242	-	-
Vermont	882	886	119	122	173	173	563	563	20	20
Massachusetts	2,084	3,269	981	997	1,023	1,406	-	655	80	210
Rhode Island	7	8	2	2	-	-	-	-	6	6
Connecticut	3,127	5,940	132	132	628	3,263	2,163	2,163	203	382
New England	**8,616**	**13,985**	**1,333**	**1,701**	**2,978**	**6,999**	**3,968**	**4,624**	**330**	**654**
New York	18,785	32,163	4,622	5,293	7,693	20,468	5,624	5,624	847	781
New Jersey	12,780	14,216	387	387	8,074	9,509	4,151	4,151	169	169
Pennsylvania	27,613	36,817	1,876	1,858	17,020	25,336	8,685	9,557	32	66
Middle Atlantic	**59,179**	**83,196**	**6,885**	**7,537**	**32,787**	**55,311**	**18,460**	**19,332**	**1,047**	**1,015**
Ohio	29,137	28,963	171	130	26,435	26,361	2,178	2,178	353	294
Indiana	22,466	22,488	89	89	22,320	22,342	-	-	57	57
Illinois	18,486	33,620	13	15	7,627	21,236	10,553	11,538	292	831
Michigan	24,517	23,879	2,323	2,323	17,556	16,916	4,251	4,251	387	389
Wisconsin	12,034	11,958	455	433	9,844	9,822	1,583	1,583	131	121
East North Central	**106,640**	**120,908**	**3,051**	**2,990**	**83,783**	**96,676**	**18,565**	**19,550**	**1,219**	**1,692**
Minnesota	9,359	9,356	142	142	7,140	7,178	1,737	1,702	339	333
Iowa	8,897	8,863	131	131	7,666	7,656	597	597	501	479
Missouri	18,045	17,459	1,100	1,100	15,195	14,615	1,236	1,236	514	508
North Dakota	4,852	4,641	517	517	4,313	4,103	-	-	22	22
South Dakota	2,973	2,973	1,731	1,731	1,198	1,198	-	-	44	44
Nebraska	6,009	6,003	183	183	4,182	4,182	1,338	1,338	305	299
Kansas	10,596	10,568	-	-	8,705	8,705	1,236	1,236	656	628
West North Central	**60,730**	**59,863**	**3,803**	**3,803**	**48,398**	**47,637**	**6,143**	**6,108**	**2,381**	**2,313**
Delaware	2,293	2,293	-	-	2,283	2,283	-	-	10	10
Maryland	11,745	11,762	474	494	9,117	9,117	1,829	1,829	325	323
District of Columbia	868	868	-	-	868	868	-	-	-	-
Virginia	16,244	16,245	3,069	3,071	9,454	9,454	3,655	3,655	65	65
West Virginia	15,311	15,167	110	110	15,201	15,057	-	-	-	-
North Carolina	22,222	22,013	1,539	1,539	15,483	15,272	5,182	5,182	18	21
South Carolina	18,824	18,724	3,425	3,423	8,575	8,476	6,799	6,799	25	25
Georgia	24,841	24,624	3,301	3,301	17,155	16,938	4,042	4,042	342	342
Florida	40,259	40,421	41	42	33,645	33,821	4,110	4,099	2,463	2,459
South Atlantic	**152,607**	**152,116**	**11,960**	**11,981**	**111,782**	**111,285**	**25,817**	**25,606**	**3,248**	**3,244**
Kentucky	16,480	15,671	778	778	15,688	14,879	-	-	14	14
Tennessee	19,544	19,544	3,778	3,778	12,054	12,054	3,711	3,711	-	-
Alabama	22,737	22,563	2,961	2,961	14,492	14,332	5,271	5,271	14	-
Mississippi	7,389	7,387	-	-	5,928	5,926	1,373	1,373	88	88
East South Central	**66,150**	**65,164**	**7,517**	**7,517**	**48,163**	**47,191**	**10,354**	**10,354**	**116**	**102**
Arkansas	9,803	9,873	1,341	1,215	6,586	6,780	1,845	1,845	30	34
Louisiana	18,258	18,459	-	-	15,959	16,160	2,236	2,238	63	63
Oklahoma	13,774	13,451	1,051	1,044	12,601	12,286	-	-	121	121
Texas	67,639	67,623	647	633	61,724	61,722	5,139	5,139	128	128
West South Central	**109,473**	**109,406**	**3,040**	**2,892**	**96,871**	**96,948**	**9,219**	**9,219**	**342**	**345**
Montana	2,822	5,084	1,912	2,488	905	2,591	-	-	5	5
Idaho	2,388	2,393	2,216	2,221	167	167	-	-	5	5
Wyoming	6,279	6,284	288	288	5,987	5,987	-	-	-	10
Colorado	7,533	7,337	1,123	1,123	6,323	6,133	-	-	88	82
New Mexico	5,723	5,723	79	79	5,628	5,628	-	-	16	16
Arizona	16,537	16,543	2,890	2,893	9,437	9,437	4,210	4,210	-	4
Utah	5,350	5,311	275	275	4,980	4,954	-	-	95	83
Nevada	5,634	5,901	1,049	1,046	4,556	4,826	-	-	30	30
Mountain	**52,265**	**54,576**	**9,830**	**10,412**	**37,982**	**39,721**	**4,210**	**4,210**	**238**	**234**
Washington	24,744	24,679	20,905	20,908	2,626	2,567	1,200	1,200	12	4
Oregon	9,621	9,807	8,147	8,164	1,471	1,640	-	-	3	3
California	24,292	30,952	12,944	12,882	6,720	13,442	4,555	4,555	63	63
Pacific	**58,657**	**65,439**	**41,997**	**41,954**	**10,817**	**17,650**	**5,755**	**5,755**	**79**	**70**
Alaska	1,949	1,925	380	366	1,221	1,218	-	-	348	342
Hawaii	1,690	1,680	3	3	1,484	1,474	-	-	203	203
Alaska & Hawaii	**3,639**	**3,606**	**384**	**369**	**2,705**	**2,692**	-	-	**551**	**545**

Note: Total may not equal sum of components due to independent rounding.

+Total includes wind turbine capacity (1999 - 43.6 MW; 1998 - 15.6 MW) and solar energy capacity (1999 - 4.6 MW; 1998 - 5.2 MW).

++Includes Combustion Turbines and Combined Cycle Plants (1999 - 70,135 MW; 1998 - 72,982 MW).

p Preliminary. r Revised.

Sources: U.S. Department of Energy. Energy Information Administration.
Annual Electric Generation Report (EIA-860A), and Annual Electric Utility Report (EIA-861).

TABLE 4

Installed Generating Capacity
Investor-Owned Electric Utilities

By State and Type of Prime Mover of the Generator

At December 31st, 1998r and 1999p - Megawatts (Nameplate)

	Total Investor-Owned Utilities +		Hydro		Conventional Steam ++		Nuclear Steam		Internal Combustion	
State/Division	1999p	1998r	1999p	1998r	1999p	1998r	1999p	1998r	1999p	1998r
Total United States	**483,746**	**531,267**	**27,626**	**29,352**	**369,001**	**412,316**	**81,736**	**84,083**	**5,353**	**5,528**
Maine	86	1,430	31	380	35	1,015	-	-	20	35
New Hampshire	2,252	2,252	65	65	1,118	1,118	1,069	1,069	-	-
Vermont	794	797	96	99	111	111	563	563	18	18
Massachusetts	1,167	2,332	979	994	175	539	-	655	13	143
Rhode Island	6	6	-	-	-	-	-	-	6	6
Connecticut	2,976	5,788	129	129	588	3,222	2,072	2,072	186	365
New England	**7,280**	**12,606**	**1,300**	**1,668**	**2,027**	**6,006**	**3,704**	**4,360**	**242**	**566**
New York	11,015	20,405	164	892	6,576	15,993	3,501	3,501	773	18
New Jersey	12,683	14,118	387	387	7,976	9,412	4,151	4,151	169	169
Pennsylvania	27,357	36,561	1,854	1,836	17,020	25,336	8,455	9,327	28	61
Middle Atlantic	**51,054**	**71,083**	**2,406**	**3,115**	**31,572**	**50,741**	**16,107**	**16,979**	**970**	**248**
Ohio	26,567	26,477	48	48	24,113	24,023	2,178	2,178	229	229
Indiana	20,412	20,434	89	89	20,290	20,312	-	-	32	32
Illinois	17,050	32,194	4	5	6,485	20,218	10,553	11,408	8	563
Michigan	22,557	21,891	2,285	2,285	15,870	15,204	4,251	4,251	151	151
Wisconsin	10,821	10,778	414	392	8,767	8,767	1,583	1,583	36	36
East North Central	**97,408**	**111,775**	**2,839**	**2,819**	**75,526**	**88,525**	**18,585**	**19,419**	**457**	**1,011**
Minnesota	7,871	7,834	136	136	5,957	5,955	1,737	1,702	41	41
Iowa	7,436	7,383	127	127	6,648	6,595	597	597	64	64
Missouri	12,571	12,427	632	632	10,580	10,436	1,236	1,236	123	123
North Dakota	488	826	-	-	488	826	-	-	-	-
South Dakota	1,040	1,040	-	-	996	996	-	-	44	44
Nebraska	-	-	-	-	-	-	-	-	-	-
Kansas	7,881	7,881	-	-	6,714	6,714	1,162	1,162	5	5
West North Central	**37,287**	**37,390**	**896**	**896**	**31,383**	**31,521**	**4,732**	**4,697**	**277**	**277**
Delaware	2,087	2,087	-	-	2,087	2,087	-	-	-	-
Maryland	11,580	11,600	474	494	9,023	9,023	1,829	1,829	254	254
District of Columbia	868	868	-	-	868	868	-	-	-	-
Virginia	15,289	15,289	2,833	2,833	9,017	9,017	3,427	3,427	12	12
West Virginia	15,311	15,167	110	110	15,201	15,057	-	-	-	-
North Carolina	20,785	20,574	1,121	1,121	14,965	14,753	4,700	4,700	-	-
South Carolina	12,626	12,526	2,923	2,922	5,330	5,231	4,373	4,373	-	-
Georgia	17,527	17,527	1,097	1,097	14,168	14,168	1,923	1,923	339	339
Florida	31,700	31,164	-	-	25,533	25,018	3,911	3,889	2,257	2,257
South Atlantic	**127,773**	**126,801**	**8,558**	**8,576**	**96,190**	**95,221**	**20,162**	**20,141**	**2,862**	**2,862**
Kentucky	9,102	8,740	110	110	8,992	8,630	-	-	-	-
Tennessee	-	-	-	-	-	-	-	-	-	-
Alabama	12,920	12,760	1,583	1,583	9,561	9,401	1,777	1,777	-	-
Mississippi	6,380	6,380	-	-	5,066	5,066	1,235	1,235	79	79
East South Central	**28,402**	**27,880**	**1,693**	**1,693**	**23,619**	**23,097**	**3,012**	**3,012**	**79**	**79**
Arkansas	6,278	6,472	65	65	4,363	4,556	1,845	1,845	6	6
Louisiana	15,007	15,208	-	-	12,771	12,972	2,236	2,236	-	-
Oklahoma	10,376	10,061	-	-	10,351	10,036	-	-	26	26
Texas	54,250	54,250	53	53	50,216	50,216	3,947	3,947	34	34
West South Central	**85,912**	**85,991**	**118**	**118**	**77,700**	**77,780**	**8,028**	**8,028**	**65**	**65**
Montana	1,384	3,645	474	1,049	905	2,591	-	-	5	5
Idaho	1,628	1,628	1,456	1,456	167	167	-	-	5	5
Wyoming	4,317	4,327	1	1	4,317	4,317	-	-	-	10
Colorado	4,272	4,137	352	352	3,895	3,760	-	-	26	26
New Mexico	4,495	4,495	-	-	4,479	4,479	-	-	16	16
Arizona	7,979	7,983	7	7	4,987	4,987	2,985	2,985	-	4
Utah	2,757	2,733	55	55	2,702	2,677	-	-	-	-
Nevada	3,920	4,190	9	9	3,882	4,152	-	-	30	30
Mountain	**30,752**	**33,138**	**2,354**	**2,929**	**25,333**	**27,129**	**2,985**	**2,985**	**81**	**95**
Washington	2,907	2,800	976	979	1,928	1,819	-	-	3	3
Oregon	2,793	3,016	1,432	1,486	1,361	1,530	-	-	-	-
California	10,244	16,862	4,950	4,970	817	7,416	4,443	4,443	33	33
Pacific	**15,944**	**22,678**	**7,359**	**7,434**	**4,105**	**10,764**	**4,443**	**4,443**	**36**	**38**
Alaska	243	244	100	100	61	58	-	-	82	86
Hawaii	1,690	1,680	3	3	1,484	1,474	-	-	203	203
Alaska & Hawaii	**1,933**	**1,925**	**104**	**104**	**1,545**	**1,532**	-	-	**285**	**289**

Note: Total may not equal sum of components due to independent rounding.

+Total includes wind turbine capacity (1999 - 27.7 MW; 1998 - 6.3 MW) and solar energy capacity (1999 - 1.9 MW; 1998 - 1.7 MW).

++Includes Combustion Turbines and Combined Cycle Plants (1999 - 52,400 MW; 1998 - 56,012 MW).

p Preliminary. r Revised.

Sources: U.S. Department of Energy. Energy Information Administration. Annual Electric Generator Report (EIA-860A).

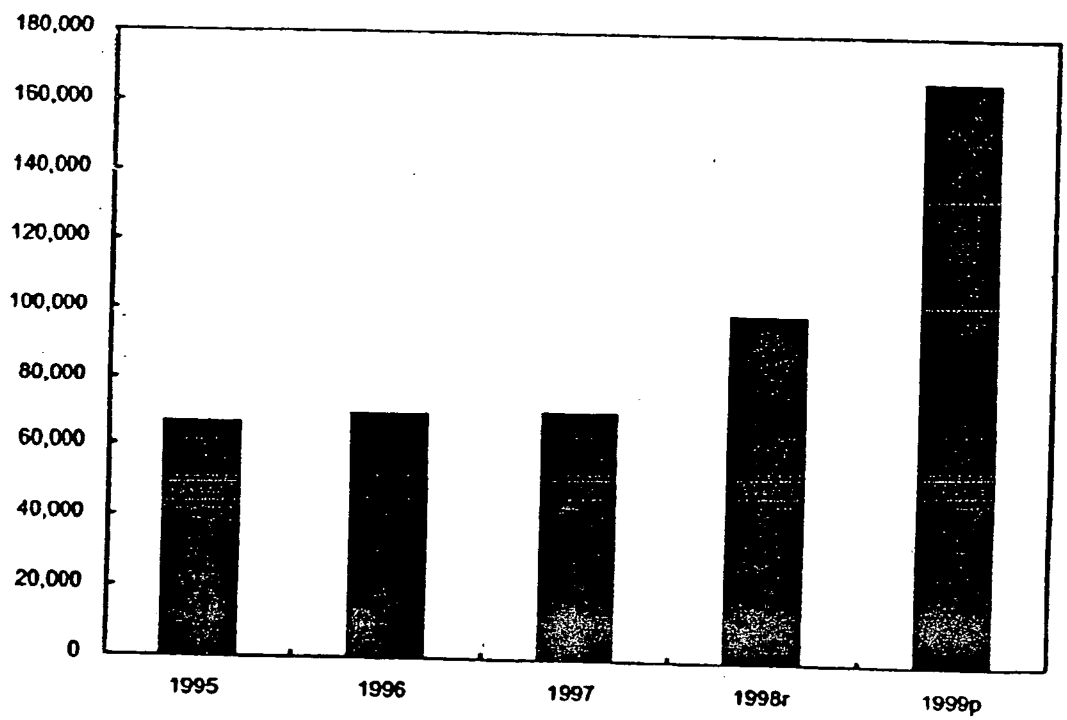
TABLE 5
Utility Generating Capacity Sold to Non-Electric Utility Generators In 1999
By State and Utility Type
Megawatts (Nameplate)

State	Total Electric Utility Industry	Investor-Owned Utilities	Cooperatives	Subtotal Government	Municipal Utilities	Federal	Power Districts, State Projects
	TOTAL (Capacity of Generators Driven by All Types of Prime Mover)						
California	6,599	6,599	-	-	-	-	-
Connecticut	2,813	2,813	-	-	-	-	-
Florida	639	-	-	639	639	-	-
Illinois	15,790	15,659	130	-	-	-	-
Louisiana	368	368	-	-	-	-	-
Maine	1,387	1,343	-	23	23	-	-
Maryland	19	19	-	-	-	-	-
Massachusetts	1,152	1,152	-	-	-	-	-
Michigan	10	-	-	10	10	-	-
Montana	2,262	2,262	-	-	-	-	-
Nevada	270	270	-	-	-	-	-
New Jersey	1,435	1,435	-	-	-	-	-
New York	13,682	13,682	-	*	*	-	-
Pennsylvania	9,270	9,270	-	-	-	-	-
Washington	51	1	-	50	50	-	-
Total	55,707	54,854	130	722	722	-	-

* *Less than 50 kilowatts.*

Source: U.S. Department of Energy. Energy Information Administration. Annual Electric Generator Report (EIA-860A).

Chart I-B
Non-Utility Generating Capacity



p Preliminary. r Revised. Sources: Edison Electric Institute's "Capacity and Generation of Non-Utility Sources of Energy" for 1995 - 1998, and U.S. Department of Energy. Energy Information Administration. Annual Electric Generator Report - Nonutilities (EIA-860B) for 1999.

TABLE 7
Capability* - Peak Load - Kilowatthour Requirements
Total Electric Utility Industry
(Excluding Alaska and Hawaii)

Year	Capability at Time of Summer Peak Load (MW	Non-Coincident Summer Peak Load (MW)	Capability at Time of Winter Peak Load (MW	Non-Coincident Winter Peak Load (MW)	Capacity Margin Based on Non-Coincident Peak Load (%)**	Annual Kilowatthour Requirements (In Millions)	Annual Load Factor Based on Peak Load (%)
1979.	544,506	398,424	554,525	368,878	26.8	2,246,927	64.4
1980.	558,237	427,058	572,195	384,567	23.5	2,292,718	61.3
1981.	572,219	429,349	586,569	397,800	25.0	2,311,026	61.4
1982.	586,142	415,618	598,066	373,985	29.1	2,258,744	62.0
1983.	596,449	447,526	612,453	410,779	25.0	2,341,633	59.7
1984.	604,240	451,150	622,125	436,374	25.3	2,445,603	61.9
1985.	621,597	460,503	636,475	423,660	25.9	2,499,228	62.0
1986.	633,291	476,320	648,721	422,857	24.8	2,532,104	60.7
1987.	648,118	496,185	662,977	448,277	23.4	2,643,532	60.8
1988.	661,580	529,460	678,940	466,533	20.0	2,768,858	59.7
1989.	673,316	523,432	685,249	496,378	22.3	2,849,824	62.2
1990.	685,091	545,537	696,757	484,014	20.4	2,886,496	60.4
1991.	690,915	551,320	703,212	485,435	20.2	2,941,869	60.9
1992.	695,436	548,707	707,752	492,983	21.1	2,942,910	61.2
1993.	694,250	575,356	711,957	521,733	17.1	3,073,303	61.0
1994.	702,985	585,320	715,090	518,253	16.7	3,138,438	61.2
1995.	714,222	620,249	727,679	544,684	13.2	3,247,736	59.8
1996.	723,571	615,529	740,526	545,061	14.9	3,289,876	61.0
1997.	729,079	631,355	743,774	560,228	13.4	3,388,440	61.3
1998r.	824,569	725,745	835,301	652,408	12.0	3,943,485	62.0
1999.	834,035	748,522	848,871	656,332	10.3	4,010,371	61.2

*Capability represents the maximum kilowatt output with all power sources available and with hydraulic equipment under actual water conditions. It must, therefore, provide the necessary allowance for maintenance, emergency outages, and system operating requirements. This rating is more indicative of the actual generating ability of existing power stations than the familiar nameplate rating as used in other tables of this publication.

**Calculated from the maximum non-coincident peak load, summer or winter, and the capability at the time of this peak load. Percent Capacity Margin is the difference between capability and peak load divided by capability multiplied by 100.

Source: North American Electric Reliability Council and Edison Electric Institute.

r Revised.

TABLE 8
Electricity Made Available in the United States
Gigawatthours

Year	Generation: Investor-Owned Utilities	Generation: Government and Cooperatives	Generation: Total Electric Utility Industry	Generation: Non Utility Sources	Generation: Total United States	Net Imports of Electric Energy+	Total Available in U.S.	Estimated Population++ (Thousands) (July 1)	Estimated kWh Per Person
1979. . . .	1,758,170	491,189	2,247,359	71,375	2,318,734	20,334	2,339,068	225,055 r	10,393 r
1980. . . .	1,782,933	503,481	2,286,414	67,945 e	2,354,359	20,925	2,375,284	227,225 r	10,453 r
1981. . . .	1,785,500	509,312	2,294,812	64,446 e	2,359,258	33,584	2,392,842	229,466 r	10,428 r
1982. . . .	1,711,576	529,635	2,241,211	61,076 e	2,302,287	30,744	2,333,031	231,664 r	10,071 r
1983. . . .	1,764,080	546,205	2,310,285	57,678 e	2,367,963	35,330	2,403,293	233,792 r	10,280 r
1984. . . .	1,848,916	567,388	2,416,304	71,520 e	2,487,824	39,661	2,527,485	235,825 r	10,718 r
1985. . . .	1,918,032	551,809	2,469,841	98,478	2,568,319	40,936	2,609,255	237,924 r	10,967 r
1986. . . .	1,928,199	559,111	2,487,310	112,008	2,599,318	35,897	2,635,215	240,133 r	10,974 r
1987. . . .	2,022,260	549,867	2,572,127	146,609	2,718,736	46,338	2,765,074	242,289 r	11,412 r
1988. . . .	2,145,601	558,650	2,704,250	174,252	2,878,502	31,770	2,910,272	244,499 r	11,903 r
1989. . . .	2,191,941	592,364	2,784,304	200,871	2,985,175	10,976	2,996,151	246,819 r	12,139
1990. . . .	2,202,553	605,598	2,808,151	232,781	3,040,932	1,980	3,042,912	249,464 r	12,198 r
1991. . . .	2,215,116	609,907	2,825,023	275,212	3,100,235	22,272	3,122,507	252,153 r	12,383
1992. . . .	2,214,475	582,744	2,797,219	309,727	3,106,946	28,348	3,135,294	255,030 r	12,294
1993. . . .	2,271,185	611,340	2,882,525	327,397	3,209,922	28,427	3,238,349	257,783	12,562
1994. . . .	2,308,684	602,028	2,910,712	372,015	3,282,727	44,192	3,326,919	260,327 r	12,780 r
1995. . . .	2,340,482	654,047	2,994,529	400,506	3,395,035	46,760	3,441,795	262,803 r	13,098 r
1996. . . .	2,372,985	700,164	3,073,149	400,220	3,473,369	37,523	3,510,893	265,229 r	13,237 r
1997. . . .	2,385,484	733,614	3,119,098	416,648	3,535,746	31,940	3,567,686	267,784 r	13,323 r
1998r. . . .	2,350,414	861,756	3,212,171	513,702	3,725,873	28,909	3,754,782	270,248 r	13,894 r
1999. . . .	2,297,834	875,839	3,173,674	569,336	3,743,010	28,993	3,772,003	272,691 p	13,833 p

Note: Total may not equal sum of components due to independent rounding.
+U.S. Department of Energy. Energy Information Administration. Electric Power Annual 1999 Volume II, Table 41.
++U.S. Department of Commerce. Bureau of Census estimates; excludes Armed Forces overseas.
p Preliminary. e Estimated.
Sources: Electric Utility Generation: U.S. Department of Energy. Energy Information Administration. Monthly Power Plant Report. (EIA-759). Non Utility Generation: Edison Electric Institute. Capacity and Generation of Non-Utility Sources of Energy through 1998, and the U.S. Department of Energy. Energy Information Administration. Annual Electric Generator Report--Nonutilities (EIA-860B) for 1999. 1999 Non Utility generation is gross generation. Prior years' are net.

TABLE 9A
Total United States Gigawatthour Source and Disposition

1979-1995 - Gigawatthours

	1979	1980	1981	1982	1983	1984	1985
SOURCE							
Generation							
Total Electric Utility Industry	2,247,359	2,286,414	2,294,812	2,241,211	2,310,285	2,416,304	2,469,841
Non Utility Sources for Own Use	65,341	60,369 •	56,045	49,072 •	42,029 •	52,125 •	70,178 •
Received by Electric Utilities from Non Utility Sources	6,034	7,576	8,401	12,004	15,649	19,395	28,300
Total Generation	2,318,734	2,354,359	2,359,258	2,302,287	2,367,963	2,487,824	2,568,319
Imports from Canada and Mexico	22,516	25,021	35,416	34,284	38,668	42,219	45,901
Total Gigawatthours	2,341,250	2,379,380	2,394,674	2,336,571	2,406,631	2,530,043	2,614,220
DISPOSITION							
Total Sales to Ultimate Customers	2,084,400	2,126,094	2,150,674	2,099,741	2,159,787	2,280,585	2,305,882
Exports to Canada and Mexico	2,182	4,096	1,832	3,540	3,337	2,558	4,965
Energy Used by Producer*	3,382	2,540	1,462	2,539	2,633	2,849	1,833
Company Use & Free Service	11,086	9,053	10,068	12,051	10,650	10,958	9,336
Lost and Unaccounted For	174,859	177,228	174,593	169,628	188,195	180,968	222,026
Non Utility Sources for Own Use	65,341	60,369 •	56,045	49,072 •	42,029 •	52,125 •	70,178 •
Total Gigawatthours	2,341,250	2,379,380	2,394,674	2,336,571	2,406,631	2,530,043	2,614,220

	1986	1987	1988	1989	1990	1991	1992
SOURCE							
Generation							
Total Electric Utility Industry	2,487,310	2,572,127	2,704,250	2,784,304	2,808,151	2,825,023	2,797,219
Non Utility Sources for Own Use	71,289	93,981	104,052	107,194	116,253	138,662	153,254
Received by Electric Utilities from Non Utility Sources	40,719	52,628	70,200	93,677	116,528	136,550	156,473
Total Generation	2,599,318	2,718,736	2,878,502	2,985,175	3,040,932	3,100,235	3,106,946
Imports from Canada and Mexico	40,713	52,219	38,837	26,110	22,506	30,812	37,204
Total Gigawatthours	2,640,031	2,770,955	2,917,339	3,011,285	3,063,438	3,131,047	3,144,150
DISPOSITION							
Total Sales to Ultimate Customers	2,354,744	2,435,483	2,554,161	2,621,003	2,683,976	2,736,586	2,734,929
Exports to Canada and Mexico	4,816	5,881	7,067	15,135	20,526	8,540	8,856
Energy Used by Producer*	1,247	2,112	1,353	3,098	3,021	2,710	2,516
Company Use & Free Service	8,536	8,401	7,351	9,789	6,589	6,788	7,088
Lost and Unaccounted For	199,399	225,097	243,355	255,066	233,073	237,761	237,507
Non Utility Sources for Own Use	71,289	93,981	104,052	107,194	116,253	138,662	153,254
Total Gigawatthours	2,640,031	2,770,955	2,917,339	3,011,285	3,063,438	3,131,047	3,144,150

	1993	1994	1995
SOURCE			
Generation			
Total Electric Utility Industry	2,882,525	2,910,712	2,994,529
Non Utility Sources for Own Use	145,883	168,826	176,107
Received by Electric Utilities from Non Utility Sources	181,515	203,189	224,398
Total Generation	3,209,923	3,282,727	3,395,035
Imports from Canada and Mexico	39,082	50,520	55,907
Total Gigawatthours	3,249,005	3,333,247	3,450,942
DISPOSITION			
Total Sales to Ultimate Customers	2,849,755	2,930,063	3,007,469
Exports to Canada and Mexico	10,655	8,328	9,147
Energy Used by Producer*	2,443	2,988	-
Company Use & Free Service	7,816	8,336	10,432
Lost and Unaccounted For	232,653	216,706	247,787
Non Utility Sources for Own Use	145,883	168,826	176,107
Total Gigawatthours	3,249,005	3,333,247	3,450,942

Please see Table 9B for 1996-1999 data

• Estimated.

**Beginning in 1995, Used by Producer included in Company Use & Free Service.*

Sources: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759), Economic Regulatory Administration, Electricity Transactions Across International Borders, and Edison Electric Institute.

TABLE 10

World Power Data

Fifteen Countries With Greatest Installed Generating Capacity

1998

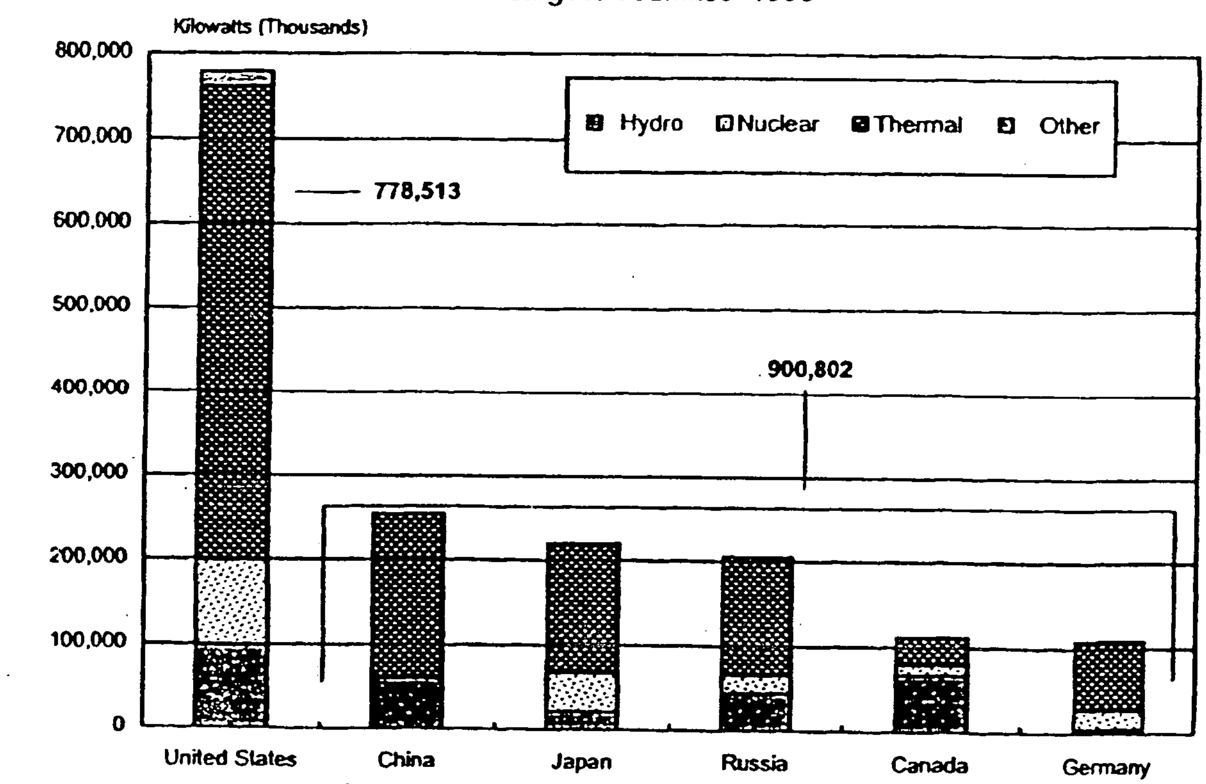
Country	Installed Capacity (Kilowatts in Thousands) Hydro	Nuclear	Thermal	Other	Total	Energy Production+ (kWh in Billions) Hydro	Nuclear	Thermal	Other	Total	Population (Thousands)	kWh Per Capita
United States	99,104	99,716	562,710	16,984	778,513	324.1	673.7	2,546.1	75.7	3,619.6	270,312	13,390
China	59,746	2,167	191,950	–	253,863	202.9	13.5	882.5	–	1,098.8	1,236,915	888
Japan	21,277	45,248	152,202	535	219,262	89.5	318.1	564.5	23.9	998.0	125,932	7,909
Russia	43,900	21,242	140,500	11	205,653	150.5	98.3	523.1	–	771.9	146,861	5,256
Canada	66,646	13,390	32,394	45	112,475	329.3	67.5	149.7	4.4	550.9	30,675	17,959
Germany	4,296	22,314	80,862	2,077	109,549	16.8	152.7	345.5	10.4	525.4	82,079	6,401
France	20,797	62,875	24,489	248	108,409	59.9	366.7	51.8	2.6	481.0	58,805	8,180
India	21,890	2,225	75,185	1,033	100,333	76.2	10.6	358.4	0.9	446.1	984,004	453
United Kingdom	1,494	12,946	55,136	135	69,711	5.1	97.7	234.1	6.1	343.1	58,970	5,818
Italy	13,060	–	49,657	811	63,528	42.0	–	195.0	6.0	243.0	56,783	4,279
Brazil	54,134	657	5,243	2,315	62,349	288.5	3.1	15.6	9.7	316.9	169,807	1,866
Ukraine	4,706	13,880	36,719	–	55,305	11.3	70.6	76.0	–	157.9	50,125	3,150
Korea, South	1,515	10,316	31,902	–	43,733	4.2	85.2	131.8	–	221.3	46,417	4,768
Spain	11,776	7,248	23,965	457	43,448	34.4	56.0	86.6	2.5	179.5	39,134	4,587
Australia	7,001	–	31,514	15	38,530	15.6	–	167.5	3.4	186.4	18,613	10,015

Note: Total may not equal sum of components due to independent rounding.
+Data presented on a net generation basis.
Sources: Capacity and production: Energy Information Administration, International Energy Database, December 1999; population: The World Almanac and Book of Facts - 1999.

Chart II-B

World Generating Capacity

Six Largest Countries -1998



Based on Table 10 as shown above.

TABLE 12
Generation
Total Electric Utility Industry

By Ownership and Type of Prime Mover Driving the Generator

Gigawatthours

Year	Total Electric Utility Industry	Investor-Owned Utilities	Cooperatives	Subtotal Government	Municipal Utilities	Federal	Power Districts, State Projects
TOTAL (Generation by All Types of Prime Mover)							
1979	2,247,359	1,756,170	54,404	436,785	87,265	235,570	113,950
1980	2,286,414	1,782,933	63,550	439,931	86,579	235,051	118,301
1981	2,294,812	1,785,500	73,314	435,998	80,701	232,222	123,075
1982	2,241,211	1,711,576	77,098	452,537	76,569	241,004	134,964
1983	2,310,285	1,764,080	84,710	461,495	73,069	258,181	130,245
1984	2,416,304	1,848,916	101,970	465,418	74,672	253,928	136,818
1985	2,469,841	1,918,032	108,321	443,488	73,864	233,063	136,560
1986	2,487,310	1,928,199	113,897	445,214	78,869	224,854	141,491
1987	2,572,127	2,022,260	122,508	427,359	86,211	205,363	135,786
1988	2,704,250	2,145,601	123,079	435,571	96,539	201,125	137,907
1989	2,784,304	2,191,941	122,810	469,554	100,311	223,531	145,712
1990	2,808,151	2,202,553	126,115	479,483	97,652	235,272	146,559
1991	2,825,023	2,215,116	127,689	482,218	96,590	241,104	144,524
1992	2,797,219	2,214,475	127,405	455,339	94,414	224,695	136,231
1993	2,882,525	2,271,185	127,738	483,602	103,076	232,110	148,416
1994	2,910,712	2,308,684	131,954	470,074	98,804	230,433	140,837
1995	2,994,529	2,340,482	134,103	519,944	103,420	263,205	153,319
1996	3,073,149	2,372,985	138,753	561,411	101,595	297,716	162,099
1997	3,119,098	2,385,484	141,356	592,258	111,133	312,120	169,004
1998r	3,212,171	2,350,414	195,756	666,000	167,880	288,506	209,613
1999	3,173,674	2,297,834	199,511	676,328	172,693	291,908	211,727
HYDRO (Generation of Generators Driven by Water Wheels and Turbines)							
1979	279,790	74,105	244	205,441	13,270	137,212	54,959
1980	276,039	70,500	267	205,272	15,603	131,909	57,760
1981	260,684	61,680	231	198,773	13,700	128,690	56,383
1982	309,213	81,527	294	227,392	17,061	148,027	62,305
1983	332,130	88,663	303	243,164	17,266	160,989	64,910
1984	321,150	83,639	279	237,232	15,775	162,268	59,190
1985	281,149	66,334	410	214,406	14,496	142,435	57,475
1986	290,844	71,356	396	219,091	16,841	141,990	60,260
1987	249,695	58,253	398	191,044	12,285	124,680	54,079
1988	222,940	48,725	396	173,819	12,644	112,015	49,160
1989	265,063	66,575	600	197,888	14,810	131,027	52,051
1990	279,926	66,658	588	212,680	15,887	140,379	56,414
1991	275,519	61,693	593	213,233	15,430	142,528	55,275
1992	239,559	58,749	598	180,212	11,675	117,174	51,363
1993	265,063	72,303	997	191,763	14,056	121,472	56,235
1994	243,693	59,783	1,099	182,811	11,847	120,946	50,018
1995	293,653	73,430	1,125	219,097	18,893	140,692	59,512
1996	324,541	79,155	867	244,519	17,524	163,248	63,747
1997	333,455	76,607	843	256,005	18,719	171,794	65,492
1998r	304,403	76,092	975	227,335	16,972	147,297	63,066
1999	293,932	62,451	761	230,720	18,678	151,764	60,277
CONVENTIONAL STEAM+ (Generation of Generators Driven by Steam Engines and Turbines)							
1979	1,708,256	1,472,652	53,609	181,995	65,100	77,948	38,947
1980	1,755,634	1,499,918	62,803	192,913	63,899	83,715	45,299
1981	1,758,660	1,492,062	72,619	193,980	62,421	80,715	50,844
1982	1,646,883	1,396,336	76,481	174,066	54,507	65,682	53,878
1983	1,682,268	1,426,449	84,015	171,804	51,503	69,237	51,063
1984	1,765,608	1,487,840	101,184	176,584	54,008	66,989	55,587
1985	1,803,323	1,503,349	107,438	192,536	56,543	77,976	58,017
1986	1,780,853	1,469,751	113,219	197,883	61,198	83,092	53,593
1987	1,865,463	1,531,106	121,845	212,512	73,082	80,890	58,540
1988	1,952,566	1,599,747	122,552	230,267	80,152	85,266	64,848
1989	1,988,003	1,637,433	122,055	228,515	83,162	77,012	68,341
1990	1,949,572	1,594,986	125,366	229,220	80,965	80,998	67,257
1991	1,935,025	1,583,168	126,914	224,943	80,384	78,266	66,293
1992	1,936,975	1,579,032	126,635	231,308	82,116	83,526	65,666
1993	2,005,448	1,616,503	126,583	262,362	88,442	101,620	72,300
1994	2,024,885	1,644,817	130,674	249,393	86,350	90,283	72,760
1995	2,025,666	1,639,046	132,815	253,805	83,832	96,897	73,076
1996	2,072,793	1,684,196	137,864	250,733	83,873	94,717	72,144
1997	2,155,251	1,747,436	140,483	267,332	92,268	98,461	76,603
1998r	2,232,190	1,739,862	173,647	318,681	122,726	95,662	100,293
1999	2,152,727	1,652,102	177,415	323,210	124,822	94,625	103,763

See page 21 for footnotes.

TABLE 12 (continued)

Generation

Total Electric Utility Industry

By Ownership and Type of Prime Mover Driving the Generator
Gigawatthours

Year	Total Electric Utility Industry	Investor-Owned Utilities	Cooperatives	Subtotal Government	Municipal Utilities	Federal	Power Districts, State Projects
NUCLEAR STEAM (Generation of Generators Driven by Nuclear Reactors)							
1979	255,155	208,788	201	46,166	5,729	20,402	20,035
1980	251,121	211,831	214	39,076	4,426	19,413	15,237
1981	272,674	231,190	241	41,243	2,585	22,810	15,847
1982	282,773	233,213	137	49,423	3,349	27,294	18,780
1983	293,677	248,379	201	45,097	2,875	27,951	14,271
1984	327,634	276,849	319	50,466	3,760	24,665	22,040
1985	383,691	347,769	323	35,599	1,885	12,646	21,069
1986	414,038	388,513	157	27,367	(41)	(230)	27,638
1987	455,270	432,239	129	22,902	(57)	(207)	23,166
1988	526,973	496,367	-	30,606	2,864	3,844	23,897
1989	529,355	487,114	-	42,240	1,429	15,492	25,319
1990	576,862	540,098	-	38,764	(18)	13,895	22,887
1991	612,565	569,300	-	43,265	-	20,310	22,955
1992	618,776	575,580	-	43,196	-	23,994	19,201
1993	610,291	581,394	-	28,897	-	9,018	19,879
1994	640,440	603,179	-	37,261	-	19,204	18,057
1995	673,402	627,058	-	46,344	-	25,617	20,728
1996	674,729	608,770	-	65,959	-	39,751	26,208
1997	629,420	560,649	-	68,771	-	41,866	26,905
1998r	673,702	533,485	20,966	119,252	27,458	45,547	46,246
1999	725,038	582,313	21,140	121,583	28,384	45,519	47,680
INTERNAL COMBUSTION (Generation of Generators Driven by Internal Combustion Engines)							
1979	4,158	625	350	3,183	3,166	8	9
1980	3,620	684	266	2,670	2,651	14	5
1981	2,795	568	224	2,003	1,995	7	1
1982	2,343	501	186	1,656	1,653	2	1
1983	2,207	588	190	1,429	1,425	3	1
1984	1,901	579	188	1,133	1,130	3	*
1985	1,662	570	150	942	938	4	*
1986	1,556	565	124	867	866	-	*
1987	1,685	649	136	900	899	-	1
1988	1,762	753	130	878	877	-	1
1989	1,880	817	155	908	907	-	1
1990	1,788	811	162	816	815	-	1
1991	1,910	954	183	773	772	-	1
1992	1,905	1,113	172	621	620	-	1
1993	1,719	985	158	576	575	-	1
1994	1,691	903	181	606	604	-	2
1995	1,793	946	163	683	681	-	2
1996	1,074	863	23	188	187	-	1
1997	963	791	31	141	137	-	4
1998r	1,871	975	169	727	720	-	8
1999	1,953	950	195	808	801	-	7
WIND++ (Generation of Generators Driven by Wind Turbines)							
1992	*	*	*	*	*	*	-
1993	*	*	*	*	-	*	-
1994	*	*	-	*	*	*	-
1995	11	*	-	11	11	*	-
1996	10	*	-	10	10	(*)	-
1997	6	-	-	6	6	*	-
1998r	3	*	-	3	3	-	-
1999	23	17	-	6	6	*	-
SOLAR+++ (Generation of Generators Driven by Photovoltaic and Solar Thermal Energy)							
1992	3	*	-	3	3	-	-
1993	4	1	-	3	3	-	-
1994	3	1	-	2	2	-	-
1995	4	1	-	3	3	-	-
1996	3	1	-	2	2	-	-
1997	3	1	-	2	2	-	-
1998r	3	1	-	2	2	-	-
1999	3	1	-	2	2	-	-

Note: Total may not equal sum of components due to independent rounding. r Revised.
+Includes Combustion Turbines and Combined Cycle Plants. ++Generation by wind available as of 1983 in previous Statistical Yearbooks.
+++Generation by solar available as of 1984 in previous Statistical Yearbooks.
*( ) Denotes negative value. * Less than five hundred thousand kilowatthours.*
Source: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759).

TABLE 13
Generation Per Kilowatt of Installed Nameplate Capacity
Total Electric Utility Industry
By Ownership and Type of Prime Mover Driving the Generator
Kilowatthours

Year	Total Electric Utility Industry	Investor-Owned	Cooperatives	Government-Owned	Total Electric Utility Industry	Investor-Owned	Cooperatives	Government-Owned
	TOTAL+				HYDRO			
1979	3,816	3,827	4,272	3,725	3,823	3,103	3,642	4,173
1980	3,773	3,789	4,344	3,841	3,639	2,929	3,985	3,968
1981	3,676	3,690	4,335	3,533	3,396	2,541	3,448	3,792
1982	3,489	3,458	3,868	3,547	3,983	3,334	3,973	4,281
1983	3,532	3,512	3,880	3,550	4,228	3,578	3,741	4,529
1984	3,632	3,624	4,345	3,535	4,025	3,273	3,444	4,381
1985	3,629	3,670	4,393	3,327	3,437	2,471	4,432	3,908
1986	3,562	3,589	4,466	3,288	3,459	2,525	3,600	3,932
1987	3,608	3,687	4,641	3,097	2,919	2,005	3,476	3,389
1988	3,751	3,864	4,667	3,127	2,580	1,656	2,809	3,058
1989	3,773	3,873	4,662	3,208	2,798	1,943	2,947	3,240
1990	3,831	3,895	4,787	3,396	3,204	2,265	3,459	3,681
1991	3,831	3,880	4,838	3,439	3,132	2,072	3,499	3,675
1992	3,776	3,865	4,856	3,216	2,685	1,930	2,718	3,077
1993	3,879	3,956	4,902	3,380	2,947	2,369	2,994	3,245
1994	3,905	4,015	5,029	3,262	2,700	1,972	2,789	3,071
1995	4,002	4,058	5,014	3,592	3,237	2,434	1,452	3,665
1996	4,078	4,088	5,109	3,848	3,565	2,617	797	4,096
1997	4,114	4,096	5,122	3,996	3,635	2,508	721	4,268
1998r	4,411	4,424	6,019	4,049	3,339	2,592	986	3,738
1999p	4,681	4,750	5,764	4,238	3,273	2,261	697	3,777
	STEAM++				INTERNAL COMBUSTION			
1979	3,849	3,881	4,381	3,527	753	347	903	956
1980	3,825	3,849	4,433	3,528	655	372	764	800
1981	3,748	3,764	4,417	3,478	501	303	638	598
1982	3,449	3,477	3,924	3,139	437	285	554	506
1983	3,463	3,519	3,928	2,966	436	377	608	448
1984	3,605	3,652	4,399	3,055	386	414	593	354
1985	3,683	3,744	4,446	3,032	338	410	460	294
1986	3,606	3,661	4,520	2,946	284	290	398	270
1987	3,736	3,798	4,695	3,008	277	265	456	270
1988	3,949	4,009	4,726	3,298	267	255	438	261
1989	3,947	4,007	4,721	3,306	251	215	485	271
1990	3,963	4,017	4,841	3,321	221	180	572	247
1991	3,976	4,016	4,890	3,399	219	185	669	236
1992	3,978	4,013	4,920	3,441	208	198	622	190
1993	4,065	4,089	4,975	3,614	178	164	552	170
1994	4,131	4,173	5,114	3,539	172	150	622	172
1995	4,167	4,191	5,172	3,686	182	157	559	193
1996	4,210	4,214	5,348	3,831	108	142	79	53
1997	4,242	4,230	5,378	3,970	97	130	102	40
1998r	4,636	4,580	6,230	4,412	183	176	569	166
1999p	4,974	4,957	5,977	4,702	204	177	650	207

+ *Total includes wind and solar.*
++ *Includes conventional and nuclear steam.*
p Preliminary, r Revised.
Source: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759) and Annual Electric Generator Report (EIA-860), as shown in Tables 2 and 12.

TABLE 14
Generation in Percent of Total
Total Electric Utility Industry
By Ownership and Type of Prime Mover Driving the Generator

Year	Investor-Owned	Cooperatives	Government-Owned	Total	Investor-Owned	Cooperatives	Government-Owned	Total	Investor-Owned	Cooperatives	Government-Owned
	TOTAL+			HYDRO				CONVENTIONAL STEAM++			
1979	78.1 %	2.4 %	19.5 %	12.4 %	3.3 %	* %	9.1 %	76.0 %	65.5 %	2.4 %	8.1 %
1980	78.0	2.8	19.2	12.1	3.1	*	9.0	76.8	65.6	2.8	8.4
1981	77.8	3.2	19.0	11.4	2.7	*	8.7	76.6	65.0	3.2	8.4
1982	78.4	3.4	20.2	13.8	3.7	*	10.1	73.5	62.3	3.4	7.8
1983	76.4	3.6	20.0	14.4	3.9	*	10.5	72.8	61.7	3.6	7.5
1984	76.5	4.2	19.3	13.3	3.5	*	9.8	73.1	61.6	4.2	7.3
1985	77.7	4.4	17.9	11.4	2.7	*	8.7	73.0	60.9	4.3	7.8
1986	77.5	4.6	17.9	11.7	2.9	*	8.8	71.6	59.1	4.5	8.0
1987	78.6	4.8	16.6	9.7	2.3	*	7.4	72.5	59.5	4.7	8.3
1988	79.3	4.6	16.1	8.2	1.8	*	6.4	72.2	59.2	4.5	8.5
1989	78.7	4.4	16.9	9.5	2.4	*	7.1	71.4	58.8	4.4	8.2
1990	78.4	4.5	17.1	10.0	2.4	*	7.6	69.4	56.8	4.5	8.2
1991	78.4	4.5	17.1	9.8	2.2	*	7.5	68.5	56.0	4.5	8.0
1992	79.2	4.6	16.3	8.6	2.1	*	6.4	69.2	56.5	4.5	8.3
1993	78.8	4.4	16.8	9.2	2.5	*	6.7	69.6	56.1	4.4	9.1
1994	79.3	4.5	16.1	8.4	2.1	*	6.3	69.6	56.5	4.5	8.6
1995	78.2	4.5	17.4	9.8	2.5	*	7.3	67.6	54.7	4.4	8.5
1996	77.2	4.5	18.3	10.6	2.6	*	8.0	67.4	54.8	4.5	8.2
1997	76.5	4.5	19.0	10.7	2.5	*	8.2	69.1	58.0	4.5	8.6
1998r	73.2	6.1	20.7	9.5	2.4	*	7.1	69.5	54.2	5.4	9.9
1999	72.4	6.3	21.3	9.3	2.0	*	7.3	67.8	52.1	5.6	10.2

Year	Total	Investor-Owned	Cooperatives	Government-Owned	Total	Investor-Owned	Cooperatives	Government-Owned
	NUCLEAR STEAM				INTERNAL COMBUSTION			
1979	11.4 %	9.3 %	* %	2.1 %	0.2 %	* %	* %	0.2 %
1980	11.0	9.3	*	1.7	0.1	*	*	0.1
1981	11.9	10.1	*	1.8	0.1	*	*	0.1
1982	12.6	10.4	*	2.2	0.1	*	*	0.1
1983	12.7	10.8	*	1.9	0.1	*	*	0.1
1984	13.5	11.4	*	2.1	0.1	*	*	0.1
1985	15.5	14.1	*	1.4	0.1	*	*	*
1986	16.6	15.5	*	1.1	0.1	*	*	*
1987	17.7	16.8	*	0.9	0.1	*	*	*
1988	19.5	18.4	-	1.1	0.1	*	*	*
1989	19.0	17.5	-	1.5	0.1	*	*	*
1990	20.5	19.2	-	1.3	0.1	*	*	*
1991	21.7	20.2	-	1.5	0.1	*	*	*
1992	22.1	20.6	-	1.5	0.1	*	*	*
1993	21.2	20.2	-	1.0	0.1	*	*	*
1994	22.0	20.7	-	1.3	0.1	*	*	*
1995	22.5	20.9	-	1.5	0.1	*	*	*
1996	22.0	19.8	-	2.1	*	*	*	*
1997	20.2	18.0	-	2.2	*	*	*	*
1998r	21.0	16.6	0.7	3.7	*	*	*	*
1999	22.8	18.3	0.7	3.8	0.1	*	*	*

Note: Total may not equal sum of components due to independent rounding.
+Total includes wind and solar, which together comprise less than one-tenth of one percent of the total.
++Includes Combustion Turbines and Combined Cycle Plants.
**Less than one-tenth of one percent.*
Source: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759), as shown in Table 12.

TABLE 15
Generation
Total Electric Utility Industry
By State and Type of Prime Mover Driving the Generator
1998 and 1999 - Gigawatthours

	Total Electric Utility Industry+		Hydro		Conventional Steam++		Nuclear Steam		Internal Combustion	
State/Division	1999	1998	1999	1998	1999	1998	1999	1998	1999	1998
Total United States	**3,173,674**	**3,212,171**	**293,932**	**304,403**	**2,152,727**	**2,232,190**	**725,036**	**673,702**	**1,953**	**1,871**
Maine	1,189	3,549	516	1,820	673	1,726	–	–	–	3
New Hampshire	13,876	14,238	339	975	4,860	4,876	8,676	8,387	–	–
Vermont	4,735	4,394	421	848	240	185	4,059	3,358	2	3
Massachusetts	4,360	26,037	189	331	2,230	19,991	1,931	5,698	10	18
Rhode Island	9	2,061	–	–	–	2,053	–	–	9	8
Connecticut	20,484	15,123	368	385	7,439	11,493	12,675	3,243	2	3
New England	**44,653**	**65,401**	**1,834**	**4,359**	**15,442**	**40,323**	**27,342**	**20,686**	**23**	**33**
New York	97,009	115,840	20,124	26,582	39,818	57,927	37,019	31,314	49	18
New Jersey	38,868	35,911	(145)	(146)	10,040	8,925	28,971	27,132	2	0
Pennsylvania	161,596	173,903	1,155	1,568	89,548	111,181	70,885	61,149	8	5
Middle Atlantic	**297,473**	**325,655**	**21,133**	**28,004**	**139,406**	**178,033**	**136,874**	**119,595**	**59**	**24**
Ohio	140,912	146,448	423	406	124,047	129,550	16,422	16,476	20	16
Indiana	114,183	112,772	407	479	113,760	112,285	–	–	16	8
Illinois	149,808	131,274	52	51	68,375	75,596	81,356	55,596	25	32
Michigan	87,866	85,146	426	352	72,785	72,242	14,591	12,494	64	58
Wisconsin	54,714	52,529	1,743	1,518	41,467	41,602	11,495	9,397	9	12
East North Central	**547,482**	**528,169**	**3,051**	**2,806**	**420,434**	**431,275**	**123,863**	**93,963**	**134**	**126**
Minnesota	44,154	43,977	857	695	29,963	31,613	13,316	11,644	18	25
Iowa	37,032	37,085	931	893	32,436	32,406	3,640	3,768	23	18
Missouri	73,505	74,894	1,740	2,269	63,141	64,067	8,587	8,517	37	42
North Dakota	31,260	30,519	2,609	2,296	28,651	28,223	–	–	–	–
South Dakota	11,416	9,089	7,536	5,758	3,872	3,320	–	–	8	12
Nebraska	29,122	28,720	860	1,683	18,131	18,743	10,091	8,259	40	35
Kansas	42,003	41,481	–	–	32,631	30,840	9,157	10,411	216	230
West North Central	**268,492**	**265,766**	**14,534**	**13,593**	**208,824**	**209,213**	**44,790**	**42,598**	**341**	**361**
Delaware	6,239	6,318	–	–	6,237	6,315	–	–	3	3
Maryland	49,324	48,514	1,422	1,740	34,575	33,428	13,312	13,331	14	15
District of Columbia	230	244	–	–	230	244	–	–	–	–
Virginia	65,071	63,815	(608)	256	37,361	36,311	28,301	27,234	17	14
West Virginia	91,678	89,605	303	361	91,375	89,244	–	–	–	–
North Carolina	109,882	113,112	2,654	4,111	69,705	70,223	37,524	38,778	–	–
South Carolina	87,347	84,397	650	2,513	35,884	33,124	50,814	48,759	*	*
Georgia	110,537	108,717	2,674	5,026	76,384	72,310	31,478	31,380	*	1
Florida	168,914	169,447	140	199	135,117	137,968	31,526	31,115	131	165
South Atlantic	**687,223**	**684,168**	**7,236**	**14,205**	**488,868**	**479,166**	**192,954**	**190,598**	**165**	**198**
Kentucky	81,658	86,151	2,557	3,116	79,102	83,035	–	–	–	*
Tennessee	89,683	94,143	6,499	9,385	55,957	56,370	27,227	28,388	–	–
Alabama	113,909	113,394	7,760	10,565	75,257	74,166	30,892	28,663	–	–
Mississippi	32,212	31,992	–	–	23,784	22,801	8,428	9,191	–	–
East South Central	**317,461**	**325,679**	**16,815**	**23,066**	**234,099**	**236,373**	**66,548**	**66,241**	**–**	*****
Arkansas	44,131	43,199	2,693	3,114	28,518	26,988	12,920	13,097	*	*
Louisiana	64,837	66,107	–		51,725	49,680	13,112	16,428	*	*
Oklahoma	50,279	51,454	3,069	3,420	47,204	48,029	–	–	6	5
Texas	292,458	293,068	1,117	1,419	254,551	252,925	36,760	38,685	31	40
West South Central	**451,705**	**453,829**	**6,879**	**7,953**	**381,998**	**377,622**	**62,791**	**68,210**	**37**	**45**
Montana	27,597	27,617	11,581	11,054	16,016	16,563	–	–	1	*
Idaho	12,588	11,978	12,465	11,978	123	*	–	–	*	*
Wyoming	42,951	44,699	1,170	1,342	41,781	43,357	–	–	–	–
Colorado	36,167	35,471	1,480	1,392	34,685	34,078	–	–	2	1
New Mexico	31,654	31,428	243	236	31,412	31,192	–	–	–	*
Arizona	83,096	81,299	10,083	11,239	42,598	39,759	30,416	30,301	–	–
Utah	38,062	35,160	1,238	1,299	34,722	33,802	–	–	103	59
Nevada	26,486	26,553	2,807	3,151	23,679	23,402	–	–	(1)	(1)
Mountain	**296,602**	**294,208**	**41,068**	**41,692**	**225,015**	**222,152**	**30,416**	**30,301**	**105**	**61**
Washington	111,949	97,128	96,472	79,410	9,391	10,802	6,086	6,916	*	*
Oregon	51,698	46,352	45,234	39,504	6,464	6,848	–	–	–	–
California	87,875	114,926	38,842	48,684	15,625	31,615	33,372	34,594	29	28
Pacific	**251,522**	**258,406**	**180,549**	**167,598**	**31,480**	**49,265**	**39,458**	**41,510**	**29**	**28**
Alaska	4,609	4,590	817	1,113	3,449	3,176	–	–	344	301
Hawaii	6,452	6,301	19	14	5,713	5,592	–	–	717	695
Alaska & Hawaii	**11,061**	**10,891**	**835**	**1,127**	**9,162**	**8,768**	**–**	**–**	**1,060**	**996**

Note: Total may not equal sum of components due to independent rounding.
+Total includes generation by wind (1998 - 3.0 GWh; 1999 - 23.0 GWh) and generation by solar (1998 - 2.5 GWh; 1999 - 3.0 GWh).
++Includes Combustion Turbines and Combined Cycle Plants (1998 - 78,484 GWh; 1999 - 77,101 GWh).
*( ) Denotes negative value. *Less than five hundred thousand kilowatthours.*
Source: U.S. Department of Energy. Energy Information Administration. Monthly Power Plant Report (EIA-759).

TABLE 16
Generation
Investor-Owned Electric Utilities
By State and Type of Prime Mover Driving the Generator
1998 and 1999 - Gigawatthours

	Total Electric Utility Industry+		Hydro		Conventional Steam++		Nuclear Steam		Internal Combustion	
State/Division	1999	1998	1999	1998	1999	1998	1999	1998	1999	1998
Total United States	**2,297,834**	**2,350,414**	**62,451**	**76,092**	**1,652,102**	**1,739,862**	**582,313**	**533,485**	**950**	**975**
Maine	1,186	3,479	513	1,814	673	1,662	–	–	–	3
New Hampshire	12,682	13,068	339	975	4,860	4,876	7,482	7,217	–	–
Vermont	4,509	4,248	351	806	84	82	4,059	3,358	1	3
Massachusetts	3,372	24,889	184	325	1,256	18,856	1,931	5,698	1	9
Rhode Island	9	2,061	–	–	*	2,053	–	–	9	8
Connecticut	19,860	14,829	363	374	7,420	11,451	12,078	3,004	*	*
New England	**41,618**	**62,574**	**1,749**	**4,294**	**14,294**	**38,980**	**25,550**	**19,277**	**12**	**24**
New York	60,431	74,197	1,995	3,589	36,846	54,062	21,581	16,538	9	7
New Jersey	38,824	35,833	(145)	(146)	9,997	8,847	28,971	27,132	2	*
Pennsylvania	159,877	172,168	1,098	1,475	89,548	111,181	69,224	59,509	7	4
Middle Atlantic	**259,132**	**282,198**	**2,948**	**4,917**	**136,391**	**174,090**	**119,776**	**103,179**	**18**	**11**
Ohio	132,065	136,554	163	167	115,468	119,901	16,422	16,476	12	11
Indiana	94,930	93,920	407	479	94,518	93,437	–	–	5	5
Illinois	146,162	127,540	17	13	64,788	71,918	81,356	55,608	1	1
Michigan	81,216	78,520	230	125	66,374	65,881	14,591	12,494	22	20
Wisconsin	49,538	47,899	1,539	1,330	36,503	37,171	11,495	9,397	1	1
East North Central	**503,912**	**484,434**	**2,356**	**2,114**	**377,651**	**388,307**	**123,883**	**93,975**	**41**	**37**
Minnesota	36,598	35,816	833	673	22,449	23,499	13,316	11,644	*	(*)
Iowa	33,457	33,256	929	891	28,887	28,597	3,640	3,768	*	*
Missouri	51,413	53,442	655	1,027	42,171	43,898	8,587	8,517	–	–
North Dakota	2,573	5,825	–	–	2,573	5,825	–	–	–	–
South Dakota	3,865	3,316	–	–	3,858	3,305	–	–	8	12
Nebraska	–	–	–	–	–	–	–	–	–	–
Kansas	36,108	35,152	–	–	27,500	25,366	8,607	9,786	*	–
West North Central	**164,015**	**166,807**	**2,418**	**2,592**	**127,439**	**130,489**	**34,150**	**33,714**	**8**	**12**
Delaware	6,056	6,165	–	–	6,056	6,165	–	–	–	–
Maryland	41,660	42,191	1,422	1,740	26,916	27,114	13,312	13,331	8	7
District of Columbia	230	244	–	–	230	244	–	–	–	–
Virginia	59,765	58,426	(937)	(440)	34,166	33,282	26,525	25,575	11	9
West Virginia	91,678	89,605	303	361	91,375	89,244	–	–	–	–
North Carolina	102,562	105,517	1,692	2,773	66,919	67,491	33,951	35,252	–	–
South Carolina	51,298	48,689	(91)	855	18,690	17,149	32,899	30,686	–	–
Georgia	76,586	75,320	1,114	2,012	60,513	58,401	14,959	14,906	*	1
Florida	130,500	132,901	–	–	101,496	103,272	28,981	29,560	23	68
South Atlantic	**560,333**	**559,057**	**3,503**	**7,301**	**406,362**	**402,361**	**150,427**	**149,310**	**42**	**85**
Kentucky	44,978	43,602	284	311	44,693	43,291	–	–	–	–
Tennessee	–	–	–	–	–	–	–	–	–	–
Alabama	69,090	69,828	3,304	4,855	53,184	53,470	12,601	11,503	–	–
Mississippi	28,463	27,891	–	–	20,877	19,619	7,585	8,271	–	–
East South Central	**142,530**	**141,321**	**3,589**	**5,167**	**118,755**	**116,380**	**20,186**	**19,774**	–	–
Arkansas	29,964	28,464	158	190	16,886	15,177	12,920	13,097	–	–
Louisiana	50,782	52,995	–	–	37,671	36,567	13,112	16,428	–	–
Oklahoma	35,606	36,871	–	–	35,606	36,871	–	–	*	*
Texas	237,939	240,982	47	178	209,673	211,284	28,218	29,518	2	2
West South Central	**354,292**	**359,312**	**205**	**367**	**299,836**	**299,899**	**54,249**	**59,043**	**2**	**2**
Montana	21,623	22,008	5,607	5,445	16,016	16,563	–	–	1	*
Idaho	8,610	8,652	8,487	8,652	123	*	–	–	*	*
Wyoming	29,774	31,031	1	1	29,774	31,030	–	–	–	–
Colorado	22,215	21,404	43	92	22,171	21,310	–	–	2	1
New Mexico	21,621	21,646	–	–	21,621	21,645	–	–	*	*
Arizona	42,465	41,023	33	32	20,867	19,508	21,565	21,483	–	–
Utah	17,235	16,306	243	301	16,992	16,004	–	–	–	–
Nevada	18,293	17,836	48	59	18,246	17,778	–	–	(1)	(1)
Mountain	**181,837**	**179,905**	**14,462**	**14,581**	**145,809**	**143,839**	**21,565**	**21,483**	**2**	**2**
Washington	12,271	12,478	5,305	4,296	6,966	8,182	–	–	*	*
Oregon	14,998	15,470	8,904	8,958	6,094	6,512	–	–	–	–
California	56,294	80,409	16,925	21,424	6,792	25,228	32,547	33,729	29	28
Pacific	**83,564**	**108,357**	**31,135**	**34,677**	**19,852**	**39,923**	**32,547**	**33,729**	**29**	**28**
Alaska	149	147	68	67	2	*	–	–	79	80
Hawaii	6,452	6,301	19	14	5,713	5,592	–	–	717	695
Alaska & Hawaii	**6,601**	**6,449**	**87**	**81**	**5,715**	**5,593**	–	–	**796**	**775**

Note: Total may not equal sum of components due to independent rounding.
+Total includes generation by wind (1998 - 0.3 GWh; 1999 - 17.4 GWh) and generation by solar (1998 - 0.8 GWh; 1999 - 0.8 GWh).
++Includes Combustion Turbines and Combined Cycle Plants (1998 - 61,263 GWh; 1999 - 60,189 GWh).
*( ) Denotes negative value. * Less than five hundred thousand kilowatthours.*
Source: U.S. Department of Energy. Energy Information Administration. Monthly Power Plant Report. (EIA-759).

TABLE 17

Generation

Total Electric Utility Industry and Investor-Owned Electric Utilities

By Month and Type of Prime Mover Driving the Generator

1996 - 1999 - Gigawatthours

Year - Month	Total Electric Utility Industry: Total+	Hydro	Conventional Steam++	Nuclear Steam	Internal Combustion	Investor-Owned Electric Utilities: Total+	Hydro	Conventional Steam++	Nuclear Steam	Internal Combustion
YEAR - 1996										
January	268,267	28,562	176,678	62,942	84	206,470	6,840	142,071	57,493	66
February	244,997	29,566	159,422	55,928	81	187,818	7,876	128,869	51,008	64
March	247,500	31,901	160,048	55,474	76	190,807	8,738	130,349	51,657	64
April	225,950	30,090	145,458	50,325	76	173,192	8,289	118,907	45,929	67
May	251,078	31,275	164,069	55,637	95	191,974	8,146	132,961	50,784	83
June	268,164	29,858	180,713	57,498	94	206,307	6,726	147,267	52,242	71
July	288,860	27,069	200,725	60,953	110	222,741	5,534	162,832	54,295	80
August	290,052	24,581	203,888	61,477	105	225,757	4,809	166,068	54,799	81
September	250,120	20,493	174,931	54,593	101	194,978	4,381	142,109	48,410	78
October	240,082	20,943	168,429	50,612	97	187,318	4,762	137,339	45,135	82
November	240,539	21,707	166,624	52,132	76	188,346	5,410	136,315	46,558	62
December	257,541	28,496	171,808	57,159	78	197,277	7,644	139,108	50,459	65
Total	3,073,149	324,541	2,072,793	674,729	1,074	2,372,985	79,155	1,684,196	608,770	863
YEAR - 1997										
January	273,583	30,739	183,854	58,914	76	209,120	7,862	148,581	52,616	61
February	233,755	29,548	153,480	50,658	68	176,229	7,235	123,732	45,204	58
March	243,939	32,916	160,535	50,414	73	184,039	8,745	130,654	44,577	63
April	230,404	30,094	154,917	45,313	80	173,984	7,765	125,820	40,329	69
May	242,710	32,342	163,271	47,032	64	181,529	7,783	131,450	42,240	56
June	266,062	32,452	181,435	52,095	79	201,853	6,909	148,074	46,809	61
July	303,697	29,755	216,457	57,352	131	233,053	5,297	176,135	51,530	92
August	293,835	25,220	207,424	61,084	106	227,869	4,607	168,085	55,093	84
September	266,136	21,859	191,603	52,586	87	208,042	4,624	155,999	47,347	72
October	252,934	22,984	182,889	46,981	79	195,865	4,830	149,033	41,936	66
November	244,758	21,561	171,600	51,535	62	188,073	5,211	138,488	44,337	55
December	267,286	23,983	187,787	55,457	59	205,827	5,738	151,405	48,631	53
Total	3,119,098	333,455	2,155,251	629,420	963	2,385,484	76,607	1,747,436	560,649	791
YEAR - 1998r										
January	265,435	27,482	179,757	57,889	125	191,668	7,469	139,010	45,049	62
February	235,340	28,776	155,349	50,999	125	167,782	7,770	120,370	39,548	62
March	256,575	30,252	172,147	53,711	135	185,039	8,552	134,563	41,947	72
April	232,457	26,889	157,843	47,503	150	169,190	8,359	123,949	37,008	86
May	265,077	30,981	182,267	51,496	160	189,405	7,549	141,317	40,689	82
June	291,029	30,216	204,933	55,732	179	211,003	7,132	159,730	44,344	88
July	317,521	26,708	229,062	61,499	207	232,812	6,108	178,335	48,554	103
August	312,538	23,282	228,711	60,369	206	232,731	4,664	179,602	48,587	110
September	279,198	19,621	202,365	57,206	170	208,387	4,310	158,339	45,690	89
October	251,380	17,537	176,508	57,429	141	188,402	4,020	137,891	46,080	76
November	239,089	18,595	163,229	57,372	138	178,034	4,432	126,979	46,057	73
December	266,532	24,062	180,018	62,497	135	195,961	5,728	139,778	49,933	70
Total	3,212,171	304,403	2,232,190	673,702	1,871	2,350,414	76,092	1,739,862	533,485	975
YEAR - 1999										
January	275,048	27,169	182,322	65,399	156	198,974	6,199	140,706	51,991	75
February	239,535	26,545	155,640	57,235	113	172,376	6,391	120,597	45,319	67
March	258,666	29,681	170,274	58,578	130	187,397	6,847	133,225	47,253	70
April	238,647	25,104	165,066	48,315	160	172,395	6,144	127,276	38,897	76
May	254,185	26,487	171,740	55,809	146	183,820	6,276	131,689	45,782	71
June	280,479	28,118	190,138	62,025	196	203,164	6,003	146,600	50,463	98
July	317,927	27,248	223,848	66,519	309	232,483	5,169	173,679	53,499	133
August	308,541	23,434	217,026	67,842	237	224,856	3,912	166,301	54,538	103
September	261,941	19,220	181,902	60,666	151	190,627	3,545	138,064	48,945	73
October	243,815	18,233	170,350	55,099	132	178,022	3,688	129,931	44,338	63
November	235,701	19,462	155,843	60,285	109	169,674	3,770	118,151	47,691	60
December	259,189	23,230	168,578	67,265	114	184,048	4,506	125,883	53,598	59
Total	3,173,674	293,932	2,152,727	725,036	1,953	2,297,834	62,451	1,652,102	582,313	950

Note: Total may not equal sum of components due to independent rounding.
+Includes generation by wind and solar. See Table 12 for details. ++Includes Combustion Turbines and Combined Cycle Plants.
Source: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759).

TABLE 18
Index of Weekly Electric Output
Total Electric Utility Industry
(Excluding Alaska and Hawaii)

Seasonally Adjusted - 1982 Average = 100

1989-1999

Week Number	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
1	127	127	139	128	129	143	152	148	135	145	149
2	122	120	122	125	130	139	138	151	147	146	156
3	117	114	122	131	134	142	133	139	160	148	150
4	116	117	130	134	131	151	142	142	146	144	139
5	118	119	125	127	133	138	139	154	150	145	144
6	134	119	116	127	134	147	150	157	144	146	145
7	124	119	123	129	132	142	144	144	150	147	145
8	132	128	126	127	143	141	137	141	143	146	151
9	129	130	128	127	144	137	142	141	145	146	158
10	132	126	125	124	139	143	139	147	146	150	154
11	123	122	130	132	139	140	133	144	148	161	164
12	127	125	125	131	144	137	134	140	147	154	156
13	122	131	127	134	137	137	138	146	145	153	156
14	128	129	128	132	135	137	138	142	144	153	154
15	128	130	129	129	133	137	139	141	147	148	155
16	125	129	131	131	133	133	142	144	149	148	158
17	126	129	125	126	128	136	139	143	146	146	154
18	127	131	127	128	128	133	140	145	144	145	152
19	122	126	127	128	129	132	143	151	145	148	152
20	122	130	137	129	129	130	143	148	141	150	150
21	130	127	131	129	124	135	143	156	143	158	152
22	129	123	142	122	126	130	143	142	141	156	155
23	122	128	129	122	119	136	150	145	138	154	154
24	119	128	130	126	129	142	139	147	138	143	163
25	124	129	132	125	127	144	140	145	139	147	140
26	124	130	132	124	130	144	138	145	152	163	148
27	127	134	137	129	137	135	134	144	147	154	158
28	127	126	129	129	135	138	147	138	138	147	157
29	118	124	135	137	139	143	146	146	153	153	144
30	127	125	135	129	135	136	154	145	146	156	158
31	127	125	129	132	141	138	152	142	148	150	165
32	115	120	129	129	134	137	150	153	144	151	158
33	121	130	130	134	135	141	157	143	144	152	155
34	127	131	132	126	143	140	148	149	143	151	155
35	130	140	142	134	146	144	145	143	141	160	154
36	125	138	132	132	150	129	142	148	147	162	158
37	130	141	142	134	130	143	140	148	151	152	157
38	125	130	141	140	134	139	139	140	159	163	150
39	121	128	131	140	139	138	138	144	152	164	149
40	125	131	134	134	135	143	143	142	153	164	157
41	127	138	135	136	139	137	144	146	160	156	152
42	129	132	133	136	137	140	142	146	150	152	159
43	125	131	134	138	138	139	143	146	149	151	154
44	126	129	134	136	135	138	144	149	151	151	153
45	126	131	142	138	140	137	148	149	149	148	150
46	124	127	133	136	137	138	148	152	152	148	149
47	126	123	130	139	137	135	141	152	158	148	153
48	129	128	131	133	135	134	145	151	148	142	146
49	131	129	127	134	132	133	142	149	148	142	156
50	137	126	121	137	131	138	148	146	154	146	155
51	142	124	127	130	131	141	141	152	150	147	156
52	136	134	121	133	142	132	147	146	146	158	165
Year	126	128	130	131	135	138	143	146	147	151	153

Note: Seasonal factors are always based on 52 weeks ending on Saturday. Therefore one week was eliminated in 1994, since that year had 53 Saturdays.
The above values are based on Edison Electric Institute's Weekly Electric Output Report.

TABLE 19

Weekly Electric Output - Total Electric Utility Industry

(Excluding Alaska and Hawaii)

1997-1999 - Gigawatthours

Week Ended		1999	Week Ended		1998	Percent Change 99/98	Week Ended		1997	Percent Change 98/97
Jan.	2	64,171	Jan.	3	61,946	3.6	Jan.	4	57,896	7.0
	9	70,366		10	61,852	13.8		11	65,741	(5.9)
	16	68,436		17	65,911	3.8		18	71,867	(8.3)
	23	63,563		24	65,198	(2.5)		25	66,257	(1.6)
	30	64,258		31	64,547	(0.4)				
Feb.	6	65,044	Feb.	7	64,943	0.2	Feb.	1	66,073	(2.3)
	13	63,977		14	64,408	(0.7)		8	63,054	3.0
	20	64,404		21	62,699	2.7		15	65,844	(2.2)
	27	66,347		28	61,327	8.2		22	61,026	2.7
Mar.	6	63,625	Mar.	7	61,959	2.7	Mar.	1	61,225	0.2
	13	65,531		14	64,390	1.8		8	60,388	2.6
	20	62,379		21	61,674	1.1		15	59,387	8.4
	27	60,520		28	59,649	1.5		22	59,339	3.9
								29	56,950	4.7
Apr.	3	58,622	Apr.	4	58,695	(0.1)	Apr.	5	55,754	5.3
	10	58,742		11	56,251	4.4		12	56,543	(0.5)
	17	59,234		18	56,175	5.4		19	56,998	(1.4)
	24	58,935		25	56,527	4.3		26	56,464	0.1
May	1	58,751	May	2	56,601	3.8	May	3	56,016	0.9
	8	59,075		9	58,363	1.2		10	56,659	3.0
	15	60,227		16	60,832	(1.0)		17	57,177	6.4
	22	61,823		23	64,533	(4.2)		24	58,640	10.0
	29	52,437		30	64,258	(2.8)		31	58,024	10.7
June	5	64,740	June	6	66,333	(2.4)	June	7	59,520	11.4
	12	71,971		13	64,274	12.0		14	61,893	3.8
	19	66,604		20	70,713	(5.8)		21	67,042	5.5
	26	70,063		27	77,400	(9.5)		28	72,792	6.3
July	3	74,630	July	4	72,841	2.5	July	5	69,519	11.3
	10	77,746		11	73,856	5.3		12	69,507	6.3
	17	73,996		18	77,565	(4.6)		19	77,484	0.1
	24	81,144		25	79,676	1.8		26	74,851	6.4
	31	84,773								
Aug.			Aug.	1	76,391	11.0	Aug.	2	74,982	1.9
	7	79,240		8	75,425	5.1		9	71,838	5.0
	14	79,310		15	77,764	2.0		16	74,381	4.5
	21	77,982		22	76,283	2.2		23	72,763	4.8
	28	77,050		29	80,335	(4.1)		30	71,138	12.9
Sept.	4	74,253	Sept.	5	75,728	(1.9)	Sept.	6	69,145	9.5
	11	73,044		12	69,817	4.6		13	68,226	2.3
	18	67,221		19	71,953	(6.6)		20	69,830	3.0
	25	63,508		26	68,881	(7.8)		27	64,036	7.6
Oct.	2	65,869	Oct.	3	67,849	(2.9)	Oct.	4	63,525	6.8
	9	62,576		10	63,058	(0.8)		11	64,585	(2.4)
	16	64,792		17	61,583	5.2		18	60,550	1.7
	23	62,696		24	60,858	3.0		25	59,922	1.6
	30	62,561		31	61,192	2.2				
Nov.	6	62,748	Nov.	7	61,577	1.9	Nov.	1	60,971	0.4
	13	62,652		14	61,761	1.4		8	60,970	1.0
	20	63,804		21	61,512	3.7		15	62,582	(1.3)
	27	60,765		28	58,753	3.4		22	64,680	(4.9)
								29	60,073	(2.2)
Dec.	4	65,608	Dec.	5	60,029	9.3	Dec.	6	62,978	(4.7)
	11	67,347		12	63,764	5.6		13	67,586	(5.7)
	18	68,160		19	65,135	4.6		20	66,015	(1.3)
	25	67,900		26	65,747	3.3		27	60,720	8.3

Note: Weekly Electric Output is the total of that reported by the individual utilities which consists of the net electric energy generated by each respondent utility plus energy received from others less energy delivered for resale.

These figures are based on the reports of investor-owned utilities, large municipal systems, and state and Federal agencies comprising approximately 87 percent of the total. They are then expanded to an estimated full coverage of the contiguous United States. As these data are for 52 weeks rather than for the calendar year and include net imports and purchases from industrial plants, they do not add to totals for the electric utility industry shown in other tables.

TABLE 21

Sources of Energy for Electric Generation
Total Electric Utility Industry

By Year and Energy Source
Gigawatthours

Year	Total Generation*	Coal	Fuel Oil	Gas	Nuclear	Hydro	Other**
1979	2,247,359	1,075,595	302,948	329,486	255,155	279,790	4,387
1980	2,286,414	1,161,969	245,547	346,233	251,121	276,039	5,506
1981	2,294,812	1,203,554	206,070	345,777	272,674	260,684	6,054
1982	2,241,211	1,192,379	146,423	305,260	282,773	309,213	5,164
1983	2,310,285	1,259,424	144,499	274,098	293,677	332,130	6,456
1984	2,416,304	1,341,681	119,808	297,394	327,634	321,150	8,638
1985	2,469,841	1,402,128	100,202	291,946	383,691	281,149	10,724
1986	2,487,310	1,385,831	136,585	248,508	414,038	290,844	11,503
1987	2,572,127	1,463,781	118,493	272,621	455,270	249,695	12,267
1988	2,704,250	1,540,653	148,900	252,801	526,973	222,940	11,984
1989	2,784,304	1,553,661	158,318	266,598	529,355	265,063	11,309
1990	2,808,151	1,559,606	117,017	264,089	576,862	279,926	10,651
1991	2,825,023	1,551,167	111,463	264,172	612,565	275,519	10,137
1992	2,797,219	1,575,895	88,916	263,872	618,776	239,559	10,200
1993	2,882,525	1,639,151	99,539	258,915	610,291	265,063	9,565
1994	2,910,712	1,635,493	91,039	291,115	640,440	243,693	8,933
1995	2,994,529	1,652,914	60,844	307,306	673,402	293,653	6,409
1996	3,073,149	1,737,368	66,962	262,335	674,729	324,541	7,214
1997	3,119,098	1,788,532	77,115	283,108	629,420	333,455	7,468
1998	3,212,171	1,807,480	110,158	309,222	673,702	304,403	7,206
1999	3,173,674	1,767,679	86,929	296,381	725,036	293,932	3,716

Note: Total may not equal sum of components due to independent rounding.

**Generation by petroleum coke included in fuel oil from 1979 to 1980, and 1983 to 1997. In 1981 and 1982 petroleum coke included in coal.*

***Includes generation by geothermal, wood, waste, wind and solar.*

Source: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759).

TABLE 22

Sources of Energy for Electric Generation in Percent of Total Total Electric Utility Industry

By Year and Energy Source

Year	Coal	Fuel Oil	Gas	Nuclear	Hydro	Other
1979	47.9 %	13.5 %	14.7 %	11.4 %	12.4 %	0.2 %
1980	50.8	10.7	15.1	11.0	12.1	0.2
1981	52.4	9.0	15.1	11.9	11.4	0.3
1982	53.2	6.5	13.6	12.6	13.8	0.2
1983	54.5	6.3	11.9	12.7	14.4	0.3
1984	55.5	5.0	12.3	13.6	13.3	0.4
1985	56.8	4.1	11.8	15.5	11.4	0.4
1986	55.7	5.5	10.0	16.6	11.7	0.5
1987	56.9	4.6	10.6	17.7	9.7	0.5
1988	57.0	5.5	9.3	19.5	8.2	0.4
1989	55.8	5.7	9.6	19.0	9.5	0.4
1990	55.5	4.2	9.4	20.5	10.0	0.4
1991	54.9	3.9	9.4	21.7	9.8	0.4
1992	56.3	3.2	9.4	22.1	8.6	0.4
1993	56.9	3.5	9.0	21.2	9.2	0.3
1994	56.2	3.1	10.0	22.0	8.4	0.3
1995	55.2	2.0	10.3	22.5	9.8	0.2
1996	56.5	2.2	8.5	22.0	10.6	0.2
1997	57.3	2.5	9.1	20.2	10.7	0.2
1998	56.3	3.4	9.6	21.0	9.5	0.2
1999	55.7	2.7	9.3	22.8	9.3	0.1

Note: Total may not equal sum of components due to independent rounding.
Source: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759), as shown in Table 21.

TABLE 25

Consumption of Fossil Fuels for Electric Generation
Total Electric Utility Industry

By Year and Kind of Fuel

Year	Coal (Thousand Short Tons)	Fuel Oil (Thousand 42-Gallon Barrels)	Gas (Million Cubic Feet)	Total Fossil Fuel in Coal Equivalents +– (Thousand Short tons)	Net Generation by Fuels+ (kWh in Millions)	Heat Rate– (Btu per kWh)	Lbs. of Coal per kWh@
1979.	527,317	523,256	3,490,517	837,371	1,708,029	10,470	0.981
1980.	569,453	420,214	3,681,595	916,952	1,753,749	10,489	0.980
1981.	598,936	351,111	3,640,154	922,133	1,755,401	10,506	0.982
1982.	593,666	249,771	3,225,518	858,869	1,644,062	10,517	0.996
1983.	625,211	245,497	2,910,767	867,621	1,678,021	10,547	0.993
1984.	664,399	204,479	3,111,342	909,156	1,758,882	10,385	0.990
1985.	693,841	173,414	3,044,083	926,793	1,794,276	10,429	0.990
1986.	685,056	230,482	2,602,370	907,720	1,770,925	10,423	0.989
1987.	717,894	199,378	2,844,051	944,420	1,854,895	10,354	0.981
1988.	758,372	248,096	2,635,613	984,969	1,942,353	10,328	0.984
1989.	766,888	267,451	2,787,012	1,004,964	1,978,577	10,312	0.987
1990.	773,549	196,054	2,787,332	988,300	1,940,712	10,368	0.997
1991.	772,268	184,886	2,789,014	987,469	1,926,801	10,322	0.996
1992.	779,860	147,335	2,765,608	983,484	1,928,683	10,340	0.990
1993.	813,508	162,454	2,682,440	1,017,086	1,997,605	10,351	0.993
1994.	817,270	151,004	2,987,146	1,033,575	2,017,646	10,425	0.999
1995.	829,007	102,150	3,196,507	1,039,174	2,021,064	10,173	1.003
1996.	874,616	112,565	2,727,173	1,063,756	2,066,666	10,176	1.007
1997.	898,332	124,739	2,955,694	1,103,037	2,148,756	10,081	1.005
1998.	910,867	178,614	3,258,054	1,147,317	2,226,860	10,360	0.998
1999.	894,120	143,830	3,113,419	1,113,614	2,150,989	10,301	1.012

Notes: As of 1994, data includes only Steam Electric and Combined Cycle Plants with a total of 50 MW or more.
Beginning in 1982, petroleum coke excluded from Coal.
Beginning in 1980, Coal Equivalents are calculated on the basis of Btu instead of generation data.
+Excludes geothermal, wood, waste, and nuclear fuels, and includes petroleum coke.
–EEI estimate (as of 1994, based on fuel receipts).
@EEI estimate.

Sources: U.S. Department of Energy. Energy Information Administration. Monthly Power Plant Report (EIA-759). Federal Energy Regulatory Commission. Monthly Report of Cost and Quality of Fuels for Electric Plants (FERC-423).

TABLE 26
Consumption of Fossil Fuels for Electric Generation
Total Electric Utility Industry
By State and Kind of Fuel - Year 1999

State/Division	Coal (Thousand Short Tons)	Fuel Oil (Thousand 42-Gallon Barrels)	Gas (Million Cubic Feet)	Total Fossil Fuel in Coal Equivalents +– (Thousand Short tons)	Net Generation by Fuels+ (kWh in Millions)	Heat Rate~ (Btu per kWh)	Lbs. of Coal per kWh@
Total United States	**894,120**	**143,830**	**3,113,419**	**1,113,614**	**2,150,989**	**10,301**	**1.012**
Maine	-	1,133	-	273	673	9,838	-
New Hampshire	1,341	2,663	572	2,140	4,859	10,723	0.806
Vermont	-	64	250	10	40	6,375	-
Massachusetts	427	600	8,141	3,589	2,240	9,112	0.795
Rhode Island	-	19	-	-	9	-	-
Connecticut	*	10,008	13,095	3,450	6,974	11,157	NM
New England	**1,768**	**14,486**	**22,057**	**9,481**	**14,796**	**10,624**	**0.803**
New York	4,412	20,243	181,823	16,465	39,867	10,203	0.806
New Jersey	2,583	1,205	32,650	4,150	10,042	10,323	0.809
Pennsylvania	34,558	5,597	10,376	36,390	89,556	9,955	0.808
Middle Atlantic	**41,554**	**27,045**	**224,849**	**57,005**	**139,466**	**10,053**	**0.808**
Ohio	52,122	985	11,105	52,841	124,067	9,969	0.849
Indiana	55,105	555	7,655	55,625	113,776	10,696	0.981
Illinois	35,995	722	40,716	38,403	68,333	10,726	1.109
Michigan	33,615	2,620	51,122	35,879	72,849	10,150	0.973
Wisconsin	23,450	341	14,077	24,340	41,133	10,681	1.175
East North Central	**200,288**	**5,222**	**124,875**	**207,088**	**420,157**	**10,390**	**0.979**
Minnesota	17,114	201	6,595	17,555	29,564	10,036	1.207
Iowa	20,071	299	5,249	20,480	32,438	11,513	1.257
Missouri	36,546	703	19,427	37,863	63,128	10,755	1.193
North Dakota	24,540	81	*	24,576	28,650	11,276	1.715
South Dakota	2,159	59	2,527	2,159	3,879	9,161	1.175
Nebraska	11,219	70	4,555	11,509	18,171	11,293	1.261
Kansas	18,888	632	35,889	21,216	32,846	11,261	1.274
West North Central	**130,538**	**2,044**	**74,241**	**135,357**	**208,678**	**10,939**	**1.297**
Delaware	1,244	2,059	19,878	2,504	6,239	10,543	0.901
Maryland	10,931	7,117	16,399	13,334	34,588	9,929	0.745
District of Columbia	-	547	-	133	230	10,778	-
Virginia	12,427	4,873	23,457	14,616	37,378	10,001	0.783
West Virginia	36,093	321	385	36,184	91,375	9,980	0.792
North Carolina	26,507	632	10,584	27,093	69,704	9,207	0.773
South Carolina	13,666	807	5,118	14,054	35,884	9,218	0.775
Georgia	31,506	1,416	20,537	32,759	76,385	10,423	0.851
Florida	26,090	56,225	319,274	54,242	135,232	9,277	0.832
South Atlantic	**158,463**	**73,997**	**415,634**	**194,920**	**487,015**	**9,693**	**0.801**
Kentucky	34,710	220	5,590	35,013	79,102	10,404	0.884
Tennessee	23,216	1,042	3,460	23,479	55,957	11,488	0.841
Alabama	33,428	295	20,918	34,471	75,257	8,838	0.913
Mississippi	6,022	4,978	101,623	12,232	23,784	10,528	0.924
East South Central	**97,377**	**6,535**	**131,592**	**105,195**	**234,098**	**10,173**	**0.885**
Arkansas	14,974	260	40,088	17,431	28,518	10,308	1.217
Louisiana	13,916	644	320,328	34,593	51,726	10,607	1.315
Oklahoma	18,353	24	169,845	28,490	47,210	11,164	1.200
Texas	97,746	288	1,207,293	179,968	254,581	10,705	1.416
West South Central	**144,989**	**1,215**	**1,737,553**	**260,482**	**382,035**	**10,719**	**1.352**
Montana	10,198	30	289	10,227	16,017	11,005	1.276
Idaho	-	*	-	-	*	-	-
Wyoming	25,639	85	167	25,677	41,781	10,694	1.229
Colorado	17,704	72	19,155	18,739	34,687	10,808	1.086
New Mexico	16,224	72	35,581	18,220	31,412	10,473	1.156
Arizona	19,025	88	50,875	21,557	42,597	10,652	1.001
Utah	14,590	52	6,478	14,894	34,669	9,655	0.855
Nevada	7,763	73	65,105	10,781	23,679	10,261	0.918
Mountain	**111,144**	**472**	**177,649**	**120,095**	**224,842**	**10,489**	**1.072**
Washington	5,707	19	6,693	5,714	9,244	9,770	1.319
Oregon	2,154	15	23,292	3,474	6,465	10,142	1.165
California	-	120	144,655	8,712	13,970	10,723	-
Pacific	**7,860**	**155**	**174,839**	**17,900**	**29,678**	**10,300**	**1.272**
Alaska	140	1,464	30,529	1,948	3,793	5,386	1.795
Hawaii	-	11,195	-	4,162	6,430	10,491	-
Alaska & Hawaii	**140**	**12,659**	**30,529**	**6,110**	**10,222**	**8,598**	**1.795**

Note: Total may not equal sum of components due to independent rounding. +Excludes geothermal, wood, waste, and nuclear fuels, and includes petroleum coke. ~EEI estimate based on fuel receipts. @EEI estimate. NM Not meaningful.
**Less than 500 of stated value (tons, 42-gallon barrels, thousand cubic feet, or thousand kilowatthours).*
Source: U.S. Department of Energy, Energy Information Administration, Monthly Power Plant Report (EIA-759).

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TABLE 27

Fossil Fuels Used for Electric Generation
Total Electric Utility Industry
Fuel Burned Under Boilers and by Internal Combustion Engines
1996 - 1999 by Geographic Division

Division	Year	Composite Averages: Cost per Million Btu Consumed	Composite Averages: Cost of Fuel per Net kWh	Composite Averages: Btu per Net kWh	Coal (a): Cost per Million Btu Consumed	Coal (a): Cost per Ton	Coal (a): Btu per Pound	Oil (b): Cost per Million Btu Consumed	Oil (b): Cost per Bbl	Oil (b): Btu per Gallon	Gas (c): Cost per Million Btu Consumed	Gas (c): Cost per MCF	Gas (c): Btu per Cu Ft
United States	1996	151.9¢	1.55¢	10,176	128.9¢	$26.45	10,263	315.7¢	$19.95	150,465	264.1¢	$2.69	1,017
	1997	152.2	1.53	10,081	127.3	26.16	10,275	288.0	18.30	151,327	276.0	2.81	1,019
	1998	143.8	1.49	10,360	125.2	25.64	10,241	213.6	13.55	151,066	238.1	2.43	1,022
	1999	144.1	1.48	10,301	121.6	24.72	10,163	252.7	16.03	151,058	257.4	2.62	1,019
New England	1996	239.3	2.56	10,683	170.2	43.55	12,793	307.9	19.71	152,427	266.2	2.75	1,031
	1997	242.7	2.39	9,839	171.2	43.67	12,756	274.3	17.51	151,952	300.6	3.09	1,029
	1998	200.7	2.11	10,494	167.6	42.94	12,810	203.5	12.97	151,708	283.7	2.92	1,029
	1999	207.5	2.21	10,624	156.8	41.22	13,147	218.4	13.98	152,354	267.1	2.74	1,025
Middle Atlantic	1996	174.5	1.78	10,188	140.8	35.08	12,460	328.7	20.62	149,395	287.7	2.96	1,028
	1997	169.1	1.72	10,167	138.3	34.39	12,436	285.3	18.02	150,332	282.2	2.90	1,027
	1998	160.3	1.64	10,238	137.6	34.33	12,478	210.6	13.30	150,381	252.0	2.60	1,030
	1999	168.5	1.69	10,053	132.5	33.48	12,638	247.4	15.62	150,352	281.1	2.88	1,025
East North Central	1996	135.9	1.37	10,106	133.3	28.29	10,611	385.8	23.60	145,641	270.7	1.83	1,019
	1997	133.6	1.38	10,308	130.7	27.68	10,588	382.3	23.20	144,482	259.7	1.99	768
	1998	132.8	1.40	10,532	129.9	27.51	10,589	288.7	17.70	145,945	230.6	1.91	830
	1999	129.3	1.34	10,390	125.9	26.60	10,562	334.4	20.36	144,969	251.2	2.06	820
West North Central	1996	94.6	1.03	10,848	92.1	15.53	8,430	434.8	25.59	140,164	241.2	2.38	985
	1997	94.9	1.00	10,551	91.7	15.39	8,394	346.5	21.46	147,461	267.8	2.64	986
	1998	91.8	1.02	11,077	88.9	14.91	8,388	292.6	17.46	142,079	224.1	2.25	1,002
	1999	91.1	1.00	10,939	87.3	14.58	8,347	359.5	21.59	142,955	249.5	2.51	1,008
South Atlantic	1996	170.9	1.67	9,751	149.3	36.68	12,285	294.7	18.72	151,275	307.9	3.12	1,012
	1997	167.9	1.60	9,534	147.6	36.34	12,311	276.1	17.63	152,021	302.9	3.16	1,044
	1998	159.7	1.57	9,820	144.7	35.58	12,296	209.2	13.27	151,080	279.3	2.93	1,048
	1999	162.7	1.58	9,693	141.1	34.84	12,344	249.7	15.89	151,520	296.6	3.08	1,040
East South Central	1996	130.5	1.31	10,029	125.3	29.35	11,714	296.1	18.64	149,907	269.0	2.79	1,038
	1997	128.9	1.31	10,143	123.9	28.70	11,584	289.8	18.82	154,607	263.4	2.73	1,035
	1998	130.3	1.35	10,344	126.0	29.10	11,543	205.7	13.51	156,398	224.5	2.33	1,039
	1999	128.1	1.30	10,173	123.2	28.03	11,376	181.1	11.84	155,611	245.2	2.52	1,027
West South Central	1996	180.5	1.89	10,491	129.1	20.13	7,798	417.9	24.81	141,347	255.9	2.63	1,027
	1997	184.9	1.87	10,101	126.7	19.69	7,765	361.5	22.37	147,329	266.7	2.74	1,026
	1998	169.0	1.80	10,672	123.4	19.34	7,837	250.1	15.80	150,442	227.0	2.33	1,028
	1999	174.5	1.87	10,719	120.4	18.86	7,836	255.9	16.07	149,492	249.0	2.55	1,025
Mountain	1996	118.0	1.22	10,307	112.0	21.82	9,741	551.7	32.44	139,987	231.0	2.36	1,020
	1997	118.3	1.22	10,346	110.7	21.52	9,723	532.9	31.14	139,142	245.5	2.51	1,022
	1998	114.9	1.20	10,460	107.3	20.83	9,708	423.9	24.69	138,687	230.8	2.36	1,021
	1999	116.4	1.22	10,489	106.1	20.69	9,755	487.2	28.33	138,459	247.5	2.53	1,024
Pacific	1996	238.7	2.34	9,802	148.5	23.96	8,066	508.5	29.89	139,932	261.9	2.68	1,025
	1997	270.8	2.81	10,370	154.5	25.19	8,153	494.4	29.06	139,974	298.0	3.04	1,019
	1998	220.7	2.21	10,033	138.4	23.07	8,332	292.4	17.69	144,034	257.5	2.63	1,020
	1999	209.8	2.16	10,300	140.8	23.77	8,444	413.2	24.43	140,747	261.8	2.65	1,012
Alaska	1996	144.6	0.79	5,440	N/A	N/A	N/A	N/A	N/A	N/A	144.6	1.45	1,001
	1997	174.0	0.99	5,713	N/A	N/A	N/A	N/A	N/A	N/A	174.0	1.74	1,000
	1998	179.8	1.07	5,924	-	N/A	N/A	N/A	N/A	N/A	179.8	1.80	1,000
	1999	159.3	0.86	5,386	-	-	-	-	-	-	159.3	1.59	1,000
Hawaii	1996	353.5	3.11	8,810	-	-	-	353.5	22.10	148,816	-	-	-
	1997	364.3	2.67	7,319	-	-	-	364.3	22.85	149,351	-	-	-
	1998	261.5	1.80	6,879	-	-	-	261.5	16.39	149,205	-	-	-
	1999	319.9	3.36	10,491	-	-	-	319.9	20.08	149,492	-	-	-

(a) Coal includes bituminous and anthracite coal and relatively small amounts of lignite.
(b) Oil includes fuel oil, crude oil, and small amounts of tar and gasoline, and petroleum coke.
(c) Gas includes natural and manufactured gas and waste gas.
N/A Not available.

Sources: U. S. Department of Energy, Energy Information Administration. Monthly Power Plant Report (EIA-759). Federal Energy Regulatory Commission. Monthly Report of Cost and Quality of Fuels for Electric Plants (FERC-423).

TABLE 29

Receipts and Average Delivered Cost of Fossil Fuels
Total Electric Utility Industry

Fuel Burned Under Boilers and by Internal Combustion Engines
By State - Year 1999

State/Division	Composite Averages: Cost per Million Btu Consumed	Composite Averages: Cost of Fuel per Net kWh	Composite Averages: Btu per Net kWh	Coal (a): Cost per Million Btu Consumed	Coal (a): Cost per Ton	Coal (a): Btu per Pound	Oil (b): Cost per Million Btu Consumed	Oil (b): Cost per Bbl	Oil (b): Btu per Gallon	Gas (c): Cost per Million Btu Consumed	Gas (c): Cost per MCF	Gas (c): Btu per Cu Ft
Total United States	144.1¢	1.48¢	10,301	121.6¢	$24.72	10,163	252.7¢	$16.03	151,058	257.4¢	$2.62	1,019
Maine	177.9	1.75	9,838	-	-	-	177.9	11.27	150,839	-	-	-
New Hampshire	172.0	1.84	10,723	151.5	39.79	13,133	213.8	13.75	153,222	261.0	2.67	1,024
Vermont	319.3	2.04	6,375	-	-	-	-	-	-	319.3	3.23	1,012
Massachusetts	217.2	1.98	9,112	173.4	45.63	13,160	243.2	15.31	149,853	265.3	2.72	1,026
Rhode Island	-	-	-	-	-	-	-	-	-	-	-	-
Connecticut	231.0	2.58	11,157	169.3	45.85	13,541	223.5	14.30	152,337	267.3	2.74	1,025
New England	207.5	2.21	10,624	156.8	41.22	13,147	218.4	13.98	152,354	267.1	2.74	1,025
New York	231.8	2.36	10,203	144.9	37.77	13,034	236.5	14.96	150,571	278.5	2.85	1,024
New Jersey	198.2	2.03	10,323	145.4	38.23	13,150	288.2	18.07	149,297	298.9	3.08	1,031
Pennsylvania	138.4	1.36	9,955	129.9	32.61	12,552	269.1	18.96	150,039	293.1	3.03	1,033
Middle Atlantic	168.5	1.69	10,053	132.5	33.48	12,638	247.4	15.62	150,352	281.1	2.88	1,025
Ohio	137.5	1.37	9,969	136.2	32.47	11,918	391.7	22.71	138,054	306.4	3.15	1,028
Indiana	112.6	1.20	10,698	111.0	23.58	10,620	426.3	24.57	137,245	289.3	2.97	1,026
Illinois	149.4	1.60	10,726	143.7	27.47	9,560	345.0	21.13	145,807	236.2	2.41	1,022
Michigan	138.2	1.40	10,150	130.6	27.39	10,487	289.2	18.11	149,118	252.3	1.53	608
Wisconsin	104.3	1.11	10,681	102.3	18.66	9,115	413.7	24.32	139,970	290.5	2.93	1,010
East North Central	129.3	1.34	10,390	125.9	26.60	10,562	334.4	20.36	144,969	251.2	2.06	820
Minnesota	111.1	1.11	10,036	109.6	19.47	8,883	420.9	24.33	137,596	266.3	2.69	1,011
Iowa	85.4	0.98	11,513	82.1	14.09	8,581	398.8	23.34	139,341	313.7	3.15	1,004
Missouri	94.8	1.02	10,755	92.6	16.56	8,948	381.5	22.12	138,034	265.6	2.66	1,003
North Dakota	73.3	0.83	11,276	73.0	9.56	6,547	417.2	24.34	138,876	404.0	4.21	1,042
South Dakota	93.8	0.86	9,161	93.6	16.16	8,630	-	-	-	-	-	-
Nebraska	57.4	0.65	11,293	55.4	9.42	8,498	431.5	24.95	137,673	281.1	2.80	995
Kansas	108.1	1.22	11,261	95.4	16.47	8,628	319.0	19.77	147,609	234.1	2.36	1,010
West North Central	91.1	1.00	10,939	87.3	14.58	8,347	359.5	21.59	142,955	249.5	2.51	1,008
Delaware	223.1	2.35	10,543	158.9	41.12	12,935	243.9	15.46	150,999	303.3	2.98	983
Maryland	158.9	1.58	9,929	137.9	35.69	12,943	257.4	16.33	151,073	307.6	3.20	1,040
District of Columbia	339.5	3.66	10,778	-	-	-	339.5	20.43	143,279	-	-	-
Virginia	149.6	1.50	10,001	134.3	34.11	12,702	229.9	14.54	150,662	299.7	3.17	1,056
West Virginia	119.1	1.19	9,980	118.2	29.22	12,361	463.5	27.08	139,102	299.8	3.00	1,000
North Carolina	145.4	1.34	9,207	143.8	35.80	12,450	398.4	23.12	138,171	283.3	2.92	1,031
South Carolina	142.2	1.31	9,218	141.6	36.29	12,809	406.7	23.60	138,151	347.3	3.57	1,028
Georgia	156.9	1.64	10,423	154.6	36.29	11,740	389.6	22.66	138,495	248.9	2.57	1,032
Florida	213.9	1.98	9,277	158.9	39.08	12,299	245.6	15.69	152,090	297.2	3.10	1,044
South Atlantic	162.7	1.58	9,693	141.1	34.84	12,344	249.7	15.89	151,520	296.6	3.08	1,040
Kentucky	106.5	1.11	10,404	105.8	24.52	11,582	431.9	25.31	139,505	340.4	3.49	1,025
Tennessee	114.0	1.31	11,488	113.1	26.32	11,635	393.3	23.11	139,900	-	-	-
Alabama	148.4	1.31	8,838	147.6	32.36	10,963	326.0	19.05	139,143	295.1	2.98	1,011
Mississippi	181.3	1.91	10,528	155.2	34.34	11,062	154.1	10.22	157,968	242.6	2.49	1,027
East South Central	128.1	1.30	10,173	123.2	28.83	11,376	181.1	11.84	155,611	245.2	2.52	1,027
Arkansas	155.8	1.61	10,308	145.6	25.19	8,651	329.3	19.47	140,807	253.0	2.59	1,022
Louisiana	203.7	2.16	10,607	139.8	22.79	8,149	204.2	13.25	154,471	249.0	2.59	1,039
Oklahoma	147.8	1.65	11,164	91.2	15.73	8,619	495.5	29.62	142,350	271.7	2.79	1,028
Texas	175.8	1.88	10,705	120.0	18.01	7,506	396.0	22.85	138,003	245.8	2.51	1,021
West South Central	174.5	1.87	10,719	120.4	18.86	7,836	255.9	16.07	149,492	249.0	2.55	1,025
Montana	73.2	0.81	11,005	72.7	12.26	8,435	491.0	28.89	140,100	184.5	2.02	1,092
Idaho	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	76.8	0.82	10,694	76.2	13.39	8,784	476.0	27.81	139,102	372.3	3.89	1,044
Colorado	105.4	1.14	10,808	98.5	19.20	9,749	543.8	30.92	135,379	256.9	2.65	1,032
New Mexico	143.5	1.50	10,473	132.9	24.27	9,132	502.3	28.69	136,000	228.2	2.31	1,013
Arizona	147.4	1.57	10,652	132.7	27.21	10,257	479.8	27.95	138,692	264.3	2.67	1,011
Utah	105.5	1.02	9,655	103.1	23.96	11,620	513.6	30.14	139,722	253.8	2.65	1,043
Nevada	157.9	1.62	10,261	129.4	29.13	11,257	452.6	26.45	139,110	242.3	2.51	1,037
Mountain	116.4	1.22	10,489	106.1	20.69	9,755	487.2	28.33	138,459	247.5	2.53	1,024
Washington	156.3	1.53	9,770	156.0	25.65	8,224	478.8	28.15	140,000	-	-	-
Oregon	139.9	1.42	10,142	107.9	19.34	8,961	414.1	24.35	140,000	193.6	1.96	1,012
California	272.5	2.92	10,723	-	-	-	327.2	19.91	144,857	272.5	2.76	1,012
Pacific	209.8	2.16	10,300	140.8	23.77	8,444	413.2	24.43	140,747	261.8	2.65	1,012
Alaska	159.3	0.86	5,386	-	-	-	-	-	-	159.3	1.59	1,000
Hawaii	319.9	3.36	10,491	-	-	-	319.9	20.08	149,492	-	-	-
Alaska & Hawaii	282.6	2.43	8,598	-	-	-	319.9	20.08	149,492	159.3	1.59	1,000

See Table 27 for footnotes.

Source: Federal Energy Regulatory Commission. Monthly Report of Cost and Quality of Fuels for Electric Plants (FERC-423).

TABLE 31
Average Cost of Fossil Fuels Delivered to Steam-Electric Utility Plants
By Year
(Cents per Million Btu)

Year	Coal	Residual Oil*	Natural Gas**	All Fossil Fuels**
1990	145.5	331.9	232.1	168.9
1991	144.7	248.5	215.3	160.3
1992	141.2	247.5	232.8	159.0
1993	138.5	238.2	258.0	159.5
1994	135.5	240.9	223.0	152.6
1995	131.8	258.6	198.4	145.3
1996	128.9	303.4	264.1	151.9
1997	127.3	278.8	276.0	152.2
1998	125.2	213.6	238.1	143.8
1999	121.8	243.3	257.4	144.1

*Residual fuel oil prices include Fuel Oil No. 4, No. 5, No. 6, and topped crude fuel oil prices. The weighted average for all fossil fuels includes both residual fuel oil prices and light oil (Fuel Oil No. 2, kerosene, and jet fuel) prices.
**Includes small quantities of coke oven gas, refinery gas and blast furnace gas.
Source: U.S. Department of Energy. Energy Information Administration. Monthly Energy Review.

TABLE 32

Energy Supply and Disposition Balance

By Year

(Quadrillion Btu)

	1978r	1979r	1980r	1981r	1982r	1983r	1984r	1985r	1986r	1987r	1988r
TOTAL SUPPLY	**82.05**	**83.91**	**82.15**	**80.91**	**78.09**	**77.07**	**80.82**	**81.06**	**81.18**	**83.55**	**87.56**
Total Production	**63.14**	**65.95**	**67.24**	**67.01**	**66.57**	**64.11**	**68.83**	**67.72**	**67.18**	**67.76**	**69.03**
Coal	14.91	17.54	18.60	18.38	18.64	17.25	19.72	19.33	19.51	20.14	20.74
Natural Gas (Dry)	19.49	20.08	19.91	19.70	18.32	16.59	18.01	16.98	16.54	17.14	17.60
Crude Oil*	18.43	18.10	18.25	18.15	18.31	18.39	18.85	18.99	18.38	17.67	17.28
Natural Gas Plant Liquids	2.25	2.29	2.25	2.31	2.19	2.18	2.27	2.24	2.15	2.22	2.26
Nuclear	3.02	2.78	2.74	3.01	3.13	3.20	3.55	4.15	4.47	4.91	5.66
Hydro**	2.94	2.93	2.90	2.76	3.27	3.53	3.39	2.97	3.07	2.63	2.33
Biomass+	2.04	2.15	2.48	2.59	2.62	2.83	2.88	2.86	2.84	2.82	2.94
Other Renewables++	0.06	0.08	0.11	0.12	0.10	0.13	0.17	0.20	0.22	0.23	0.22
Total Imports	**19.25**	**19.62**	**15.97**	**13.97**	**12.09**	**12.03**	**12.77**	**12.10**	**14.44**	**15.76**	**17.56**
Crude Oil	13.46	13.82	11.16	9.34	7.42	7.08	7.28	6.81	9.00	10.07	11.00
Refined Petroleum Products	4.36	4.11	3.50	3.30	3.36	3.57	4.15	3.80	4.20	4.09	4.75
Natural Gas	0.99	1.30	1.01	0.92	0.95	0.94	0.85	0.95	0.75	0.99	1.30
Other	0.44	0.39	0.30	0.41	0.36	0.44	0.49	0.54	0.49	0.61	0.51
Adjustments	**(0.34)**	**(1.66)**	**(1.06)**	**(0.07)**	**(0.57)**	**0.94**	**(0.79)**	**1.24**	**(0.44)**	**0.03**	**0.97**
TOTAL DISPOSITION	**82.05**	**83.91**	**82.15**	**80.91**	**78.09**	**77.07**	**80.82**	**81.06**	**81.18**	**83.55**	**87.56**
Total Exports	**1.93**	**2.87**	**3.72**	**4.33**	**4.63**	**3.72**	**3.80**	**4.23**	**4.06**	**3.85**	**4.42**
Coal	1.08	1.75	2.42	2.94	2.79	2.04	2.15	2.44	2.25	2.09	2.50
Other	0.85	1.12	1.30	1.39	1.84	1.68	1.65	1.79	1.81	1.76	1.92
Total Consumption	**80.12**	**81.04**	**78.43**	**76.58**	**73.46**	**73.35**	**77.02**	**76.83**	**77.12**	**79.70**	**83.14**
Coal#	13.89	15.10	15.39	15.89	15.30	15.88	17.06	17.47	17.24	18.02	18.89
Natural Gas (Dry)	20.00	20.67	20.39	19.93	18.51	17.36	18.51	17.83	16.71	17.74	18.55
Refined Petroleum Products	37.97	37.12	34.20	31.93	30.23	30.05	31.05	30.92	32.20	32.87	34.22
Nuclear	3.02	2.78	2.74	3.01	3.13	3.20	3.55	4.15	4.47	4.91	5.66
Hydro**	3.14	3.14	3.12	3.11	3.57	3.90	3.80	3.40	3.45	3.12	2.66
Biomass+	2.04	2.15	2.48	2.59	2.62	2.83	2.88	2.86	2.84	2.82	2.94
Other Renewables++	0.06	0.08	0.11	0.12	0.11	0.13	0.17	0.20	0.22	0.23	0.22

Note: Total may not equal sum of components due to independent rounding.
** Includes Lease Condensate*
*** Includes hydroelectric pumped storage, which represents total pumped storage facility production minus energy used for pumping.*
+ Wood and wood waste. Values are estimated.
++ Includes geothermal, solar and wind.
 # Includes coal coke net imports.
r Revised.
( ) Denotes negative value.
Source: EEI calculations based on data provided by the U.S. Department of Energy, Energy Information Administration in the Annual Energy Review 1999.

TABLE 32 (cont.)

Energy Supply and Disposition Balance

By Year

(Quadrillion Btu)

	1989r	1990r	1991r	1992r	1993r	1994r	1995r	1996r	1997r	1998r	1999p
TOTAL SUPPLY	**89.47**	**89.21**	**89.29**	**90.54**	**91.65**	**93.25**	**95.45**	**98.56**	**98.85**	**98.95**	**100.42**
Total Production	**69.46**	**70.85**	**70.52**	**70.06**	**68.37**	**70.83**	**71.29**	**72.58**	**72.53**	**72.55**	**72.52**
Coal	21.35	22.46	21.59	21.63	20.25	22.11	22.03	22.68	23.21	23.72	23.33
Natural Gas (Dry)	17.85	18.36	18.23	18.38	18.58	19.35	19.10	19.36	19.39	19.29	19.30
Crude Oil*	16.12	15.57	15.70	15.22	14.49	14.10	13.89	13.72	13.66	13.24	12.54
Natural Gas Plant Liquids	2.16	2.18	2.31	2.36	2.41	2.39	2.44	2.53	2.50	2.42	2.51
Nuclear	5.68	6.16	6.58	6.61	6.52	6.84	7.18	7.17	6.68	7.16	7.73
Hydro**	2.86	3.01	2.98	2.58	2.85	2.65	3.18	3.56	3.68	3.30	3.16
Biomass+	3.05	2.67	2.68	2.83	2.78	2.91	3.04	3.10	2.98	2.99	3.51
Other Renewables++	0.41	0.44	0.45	0.46	0.48	0.48	0.43	0.45	0.44	0.44	0.44
Total Imports	**18.96**	**18.95**	**18.50**	**19.58**	**21.50**	**22.73**	**22.54**	**23.99**	**25.52**	**26.86**	**26.92**
Crude Oil	12.60	12.77	12.55	13.22	14.75	15.34	15.63	16.26	17.87	18.92	18.62
Refined Petroleum Products	4.56	4.35	3.80	3.75	3.76	3.90	3.23	4.01	3.87	3.99	3.91
Natural Gas	1.39	1.55	1.80	2.16	2.40	2.68	2.90	3.00	3.06	3.22	3.64
Other	0.41	0.28	0.35	0.45	0.59	0.81	0.78	0.72	0.72	0.73	0.75
Adjustments	**1.05**	**(0.59)**	**0.28**	**0.90**	**1.79**	**(0.32)**	**1.63**	**1.98**	**0.80**	**(0.46)**	**0.98**
TOTAL DISPOSITION	**89.47**	**89.21**	**89.29**	**90.54**	**91.65**	**93.25**	**95.45**	**98.56**	**98.85**	**98.95**	**100.42**
Total Exports	**4.77**	**4.87**	**5.16**	**4.96**	**4.28**	**4.08**	**4.54**	**4.66**	**4.57**	**4.34**	**3.82**
Coal	2.64	2.77	2.85	2.68	1.96	1.88	2.32	2.37	2.19	2.05	1.53
Other	2.13	2.10	2.31	2.28	2.32	2.20	2.22	2.29	2.38	2.29	2.29
Total Consumption	**84.70**	**84.34**	**84.13**	**85.58**	**87.37**	**89.17**	**90.91**	**93.90**	**94.28**	**94.61**	**96.60**
Coal#	18.96	19.11	18.78	19.19	19.80	20.02	20.09	20.96	21.49	21.66	21.76
Natural Gas (Dry)	19.38	19.30	19.61	20.13	20.83	21.29	22.16	22.56	22.53	21.92	22.10
Refined Petroleum Products	34.21	33.55	32.85	33.53	33.84	34.67	34.55	35.76	36.27	36.93	37.71
Nuclear	5.68	6.16	6.58	6.61	6.52	6.84	7.18	7.17	6.68	7.16	7.73
Hydro**	3.00	3.10	3.18	2.82	3.11	2.94	3.45	3.88	3.90	3.51	3.35
Biomass+	3.05	2.67	2.68	2.83	2.78	2.91	3.04	3.10	2.98	2.99	3.51
Other Renewables++	0.42	0.45	0.47	0.48	0.50	0.50	0.45	0.46	0.44	0.44	0.44

Note: Total may not equal sum of components due to independent rounding.

** Includes Lease Condensate*

*** Includes hydroelectric pumped storage, which represents total pumped storage facility production minus energy used for pumping.*

+ Wood and wood waste. Values are estimated.

++ Includes geothermal, solar and wind.

 # Includes coal coke net imports.

p Preliminary. r Revised.

( ) Denotes negative value.

Source: EEI calculations based on data provided by the U.S. Department of Energy, Energy Information Administration in the Annual Energy Review 1999.

TABLE 38

Energy Sales - Total Electric Utility Industry

By Year and Class of Service

Gigawatthours

Year	Total Sales	Exports to Canada and Mexico	Total Sales to Ultimate Customers	Residential	Commercial*	Industrial*	Street and Highway Lighting	Other Pub. Auth. and Other Sales**	Railroads and Railways	Inter departmental
1979. .	2,086,582	2,182	2,084,400	695,996	494,723	817,617	14,792	49,604	4,258	7,412
1980. .	2,130,190	4,096	2,126,094	734,411	524,122	793,812	14,832	48,284	4,275	6,358
1981. .	2,152,506	1,832	2,150,674	730,479	521,698	819,641	14,683	53,737	4,208	6,230
1982. .	2,103,281	3,540	2,099,741	732,678	516,959	770,398	14,238	55,745	4,288	5,438
1983. .	2,163,124	3,337	2,159,787	750,293	545,601	782,984	13,944	57,287	4,300	5,398
1984. .	2,283,143	2,558	2,280,585	782,608	578,083	835,486	14,205	59,894	4,483	5,828
1985. .	2,310,847	4,965	2,305,882	792,875	605,865	820,301	14,644	62,165	4,704	5,328
1986. .	2,359,560	4,816	2,354,744	820,015	628,965	818,982	15,037	61,888	4,689	5,167
1987. .	2,441,364	5,881	2,435,483	846,457	658,445	843,709	14,386	63,047	4,898	4,541
1988. .	2,561,228	7,067	2,554,161	886,070	697,832	881,790	14,609	64,560	5,078	4,222
1989. .	2,636,138	15,135	2,621,003	898,802	715,915	912,772	14,570	69,334	5,294	4,316
1990. .	2,704,502	20,526	2,683,976	915,799	738,869	931,877	15,215	72,771	5,255	4,190
1991. .	2,745,126	8,540	2,736,586	948,807	753,298	934,906	15,633	78,073	5,253	2,618
1992. .	2,743,785	8,858	2,734,929	929,290	755,658	949,259	15,795	77,200	5,166	2,562
1993. .	2,860,410	10,655	2,849,755	994,144	803,094	956,611	18,134	69,685	5,378	2,711
1994. .	2,936,391	6,328	2,930,063	1,008,492	833,508	990,254	18,462	70,572	5,788	2,985
1995. .	3,016,616	9,147	3,007,469	1,042,399	863,501	1,006,178	17,887	69,929	5,481	2,094
1996. .	3,103,004	9,020	3,093,984	1,082,358	887,086	1,028,427	18,037	70,299	5,302	2,475
1997. .	3,154,164	15,560	3,138,604	1,078,605	929,031	1,027,667	19,739	75,823	5,321	2,617
1998r.	3,258,046	18,228	3,239,818	1,127,735	968,528	1,040,038	16,282	87,236	N/A	N/A
1999p.	3,250,121	14,222	3,235,899	1,140,761	970,601	1,017,783	15,894	90,860	N/A	N/A

Note: Total may not equal sum of components due to independent rounding. p Preliminary. N/A Not Available.

* Commercial and Industrial are not wholly comparable on a year-to-year basis due to changes from one classification to another.

** Starting with 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in "Other Sales."

Sources: Edison Electric Institute and U.S. Department of Energy. Energy Information Administration. Annual Electric Utility Report. (EIA-861), and Electric Power Annual 1998, Volume II, Table 43.

TABLE 39

Energy Sales - Investor-Owned Electric Utilities

By Year and Class of Service

Gigawatthours

Year	Total Sales	Sales for Resale+	Total Sales to Ultimate Customers	Residential	Commercial*	Industrial*	Street and Highway Lighting	Other Pub. Auth. and Other Sales**	Railroads and Railways	Inter departmental
1979. .	1,719,640	117,408	1,602,232	509,655	394,511	648,031	10,854	34,165	2,103	2,913
1980. .	1,732,553	118,745	1,613,808	532,025	408,265	623,472	10,820	34,449	2,156	2,821
1981. .	1,745,234	116,248	1,628,986	527,119	420,014	628,481	10,918	37,623	1,939	2,892
1982. .	1,701,020	109,796	1,591,224	530,713	431,598	578,380	10,716	38,987	1,924	2,925
1983. .	1,749,915	109,540	1,640,375	546,080	445,300	597,405	10,445	38,396	1,929	2,820
1984. .	1,841,195	104,168	1,737,027	563,703	473,470	643,466	10,379	40,760	2,045	3,204
1985. .	1,871,702	102,773	1,768,929	573,253	498,320	638,513	10,339	43,565	2,252	2,687
1986. .	1,913,682	105,621	1,808,061	594,019	518,639	637,116	10,348	42,948	2,261	2,729
1987. .	1,988,233	108,675	1,879,558	618,496	544,616	658,417	10,395	43,195	2,239	2,200
1988. .	2,078,543	109,468	1,969,075	648,522	575,617	685,836	10,399	44,415	2,399	1,887
1989. .	2,129,953	108,601	2,021,352	657,956	593,020	707,108	10,441	48,433	2,482	1,913
1990. .	2,167,884	107,140	2,060,744	667,563	610,415	717,355	10,476	51,021	2,485	1,429
1991. .	2,233,555	133,329	2,100,226	682,427	623,185	715,496	10,505	54,860	2,549	1,194
1992. .	2,247,951	146,785	2,101,166	675,435	624,463	728,943	10,597	58,155	2,508	1,068
1993. .	2,348,320	173,139	2,175,181	717,485	663,865	733,482	10,882	46,162	2,447	860
1994. .	2,397,952	164,723	2,233,229	724,843	693,622	753,580	10,763	46,669	2,724	1,027
1995. .	2,479,064	192,694	2,286,370	750,878	714,136	759,624	10,661	48,069	2,531	470
1996. .	2,623,940	288,257	2,335,683	770,726	731,286	772,006	11,857	46,566	2,532	710
1997. .	2,766,521	397,233	2,369,288	767,530	748,000	789,958	11,319	49,692	2,357	432
1998r.	2,851,915	424,182	2,427,733	796,267	770,512	795,971	11,282	53,701	N/A	N/A
1999p.	N/A	N/A	2,397,707	802,834	763,913	766,789	10,374	53,797	N/A	N/A

Note: Total may not equal sum of components due to independent rounding. p Preliminary. N/A Not Available.

+To non-investor-owned electric utilities and exports.

* Commercial and Industrial are not wholly comparable on a year-to-year basis due to changes from one classification to another.

** Starting with 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in "Other Sales."

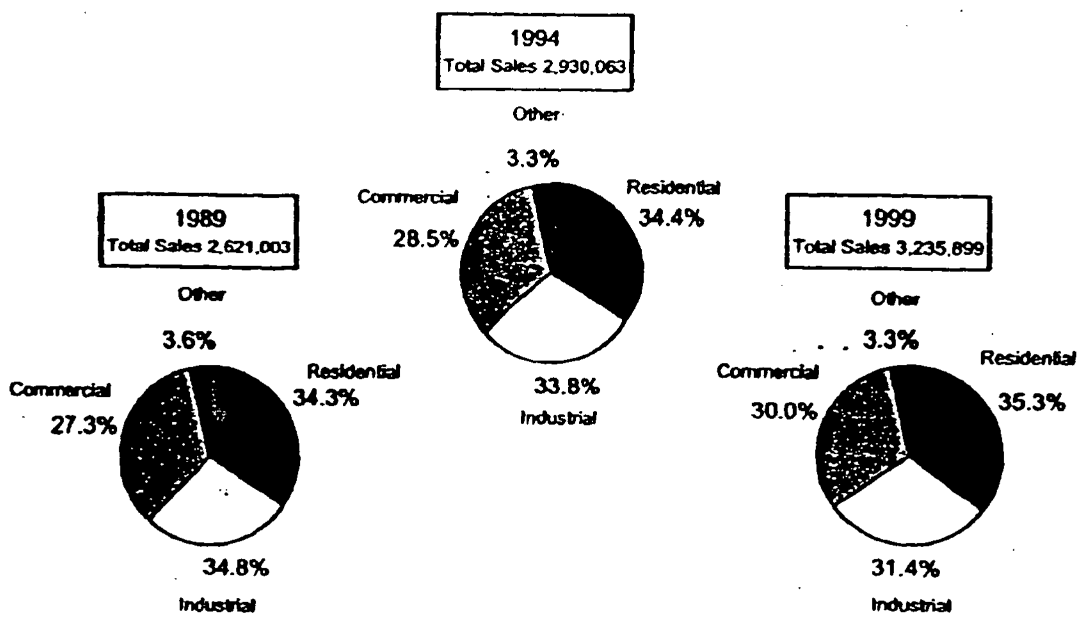
Sources: Edison Electric Institute and U.S. Department of Energy. Energy Information Administration. Annual Electric Utility Report. (EIA-861).

TABLE 40
Energy Sales in Percent of Total
Total Electric Utility Industry
By Year and Class of Service

Year	Residential	Commercial	Industrial	Street and Highway Lighting	Other Public Authorities and Other Sales*	Railroads and Railways	Inter-depart-mental
1979.	33.4	23.7	39.2	0.7	2.4	0.2	0.4
1980.	34.5	24.7	37.3	0.7	2.3	0.2	0.3
1981.	34.0	24.2	38.1	0.7	2.5	0.2	0.3
1982.	34.9	24.6	36.7	0.7	2.7	0.2	0.2
1983.	34.7	25.3	36.3	0.6	2.7	0.2	0.2
1984.	34.3	25.4	36.6	0.6	2.6	0.2	0.3
1985.	34.4	26.3	35.6	0.6	2.7	0.2	0.2
1986.	34.8	26.7	34.8	0.6	2.7	0.2	0.2
1987.	34.8	27.0	34.6	0.6	2.6	0.2	0.2
1988.	34.7	27.3	34.5	0.6	2.5	0.2	0.2
1989.	34.3	27.3	34.8	0.6	2.6	0.2	0.2
1990.	34.1	27.5	34.7	0.6	2.7	0.2	0.2
1991.	34.7	27.5	34.1	0.6	2.8	0.2	0.1
1992.	34.0	27.6	34.7	0.6	2.8	0.2	0.1
1993.	34.9	28.2	33.6	0.6	2.4	0.2	0.1
1994.	34.4	28.5	33.8	0.6	2.4	0.2	0.1
1995.	34.7	28.7	33.5	0.6	2.2	0.2	0.1
1996.	33.0	31.3	33.1	0.5	2.0	0.1	0.0
1997.	34.4	29.6	32.7	0.6	2.4	0.2	0.1
1998.	34.8	29.9	32.1	0.5	2.7	N/A	N/A
1999.	35.3	30.0	31.4	0.5	2.8	N/A	N/A

Based on sales data in Table 38.
** Beginning with 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in "Other Sales."*

Chart VI-B
Energy Sales to Ultimate Consumers
Total Electric Utility Industry
by Year and Class of Service
Gigawatthours



Based on Tables 39 and 40.

TABLE 41

Energy Sales
Total Electric Utility Industry

By State and Class of Service
Year 1999 - Gigawatthours

State/Division	Total to Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Sales
Total United States	**3,235,899**	**1,140,761**	**970,601**	**1,017,783**	**15,894**	**90,860**
Maine	11,944	3,704	3,491	4,687	50	11
New Hampshire	9,723	3,572	3,512	2,510	38	90
Vermont	5,527	1,999	1,896	1,587	20	25
Massachusetts	47,821	17,392	20,458	9,409	398	162
Rhode Island	6,655	2,663	2,701	1,137	38	115
Connecticut	29,803	11,619	11,834	5,836	141	373
New England	**111,472**	**40,949**	**43,893**	**25,167**	**686**	**778**
New York	129,834	42,538	49,366	25,202	1,040	11,688
New Jersey	70,582	24,550	32,436	13,071	508	17
Pennsylvania	96,023	41,244	24,799	28,879	438	663
Middle Atlantic	**296,439**	**108,332**	**106,601**	**67,152**	**1,987**	**12,369**
Ohio	164,271	46,629	39,461	74,293	738	3,150
Indiana	98,735	28,806	20,161	47,230	350	190
Illinois	132,237	39,623	41,891	41,612	244	8,867
Michigan	103,480	30,661	35,062	38,808	535	414
Wisconsin	63,547	19,502	17,638	25,665	324	419
East North Central	**560,270**	**165,220**	**154,212**	**225,609**	**2,190**	**13,039**
Minnesota	57,399	17,998	10,909	27,764	274	454
Iowa	38,034	11,867	8,269	16,499	152	1,247
Missouri	68,976	27,766	24,042	16,122	266	780
North Dakota	9,112	3,307	2,350	3,013	56	387
South Dakota	7,922	3,302	2,291	1,949	55	326
Nebraska	22,810	7,929	6,661	6,883	202	1,134
Kansas	33,820	11,347	11,822	10,215	173	263
West North Central	**238,073**	**83,516**	**66,343**	**82,445**	**1,179**	**4,590**
Delaware	10,494	3,532	3,348	3,559	41	13
Maryland	59,086	23,342	24,988	9,936	290	529
District of Columbia	10,418	1,643	8,146	249	97	282
Virginia	93,032	35,779	26,968	20,269	355	9,662
West Virginia	27,144	9,452	6,473	11,126	71	21
North Carolina	115,015	43,648	35,069	34,165	443	1,690
South Carolina	73,304	23,699	16,585	32,117	146	757
Georgia	112,656	41,767	34,093	35,255	552	988
Florida	187,270	93,846	69,056	18,579	729	5,061
South Atlantic	**688,419**	**276,708**	**224,727**	**165,256**	**2,725**	**19,003**
Kentucky	79,098	22,548	13,222	40,054	286	2,988
Tennessee	93,180	35,425	25,228	31,493	984	51
Alabama	80,401	27,048	18,145	34,533	388	288
Mississippi	43,980	16,321	11,151	15,735	283	489
East South Central	**296,659**	**101,342**	**67,746**	**121,816**	**1,941**	**3,816**
Arkansas	39,789	14,045	8,374	16,680	151	538
Louisiana	78,267	26,426	17,581	31,484	357	2,419
Oklahoma	46,737	18,301	12,398	13,271	227	2,539
Texas	301,844	108,591	79,388	99,741	1,112	13,012
West South Central	**466,638**	**167,364**	**117,742**	**161,176**	**1,847**	**18,508**
Montana	12,132	3,664	3,025	5,108	49	286
Idaho	21,846	6,806	6,450	8,295	42	253
Wyoming	11,782	2,025	2,514	7,065	32	146
Colorado	40,571	13,131	17,006	9,521	231	682
New Mexico	17,998	4,645	5,887	5,922	107	1,436
Arizona	57,662	22,517	19,776	12,456	689	2,223
Utah	21,879	6,236	7,282	7,568	79	714
Nevada	26,253	8,386	6,049	10,861	152	806
Mountain	**210,123**	**67,411**	**67,990**	**66,795**	**1,381**	**6,546**
Washington	94,155	32,817	23,009	34,624	329	3,377
Oregon	46,996	18,058	14,912	13,558	173	294
California	211,981	74,490	78,154	49,596	1,376	8,367
Pacific	**353,133**	**125,365**	**116,075**	**97,777**	**1,878**	**12,038**
Alaska	5,293	1,866	2,385	844	25	173
Hawaii	9,381	2,689	2,887	3,748	57	-
Alaska & Hawaii	**14,674**	**4,555**	**5,273**	**4,591**	**81**	**173**

Note: Total may not equal sum of components due to independent rounding.
Source: U.S. Department of Energy. Energy Information Administration. Annual Electric Utility Report (EIA-861).

TABLE 42
Energy Sales
Investor-Owned Electric Utilities
By State and Class of Service
Year 1999 - Gigawatthours

State/Division	Total to Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Sales
Total United States	2,397,707	802,834	763,913	766,789	10,374	53,797
Maine	11,422	3,559	3,433	4,378	47	4
New Hampshire	8,956	3,158	3,272	2,401	35	90
Vermont	4,588	1,559	1,625	1,383	13	6
Massachusetts	40,985	14,873	19,010	6,852	247	3
Rhode Island	6,613	2,638	2,696	1,126	38	115
Connecticut	27,998	11,125	11,352	5,196	116	200
New England	100,560	36,913	41,398	21,335	496	418
New York	94,052	32,690	39,102	19,209	379	2,672
New Jersey	69,505	24,057	32,099	12,834	502	13
Pennsylvania	92,602	39,061	24,099	28,366	433	643
Middle Atlantic	256,159	95,808	95,300	60,409	1,315	3,327
Ohio	149,099	39,995	36,382	69,011	662	3,050
Indiana	80,705	21,065	17,178	42,092	288	82
Illinois	122,149	34,788	39,046	39,479	206	8,631
Michigan	93,529	27,382	31,803	33,699	470	175
Wisconsin	53,518	15,611	15,549	21,754	266	338
East North Central	499,000	138,841	139,958	206,034	1,892	12,276
Minnesota	39,233	9,122	6,241	23,495	159	217
Iowa	28,979	7,812	6,422	13,687	120	939
Missouri	47,874	17,335	18,925	10,957	222	435
North Dakota	4,515	1,632	1,548	1,215	48	72
South Dakota	4,426	1,453	1,512	1,397	33	31
Nebraska	-	-	-	-	-	-
Kansas	24,531	8,271	9,179	6,917	141	22
West North Central	149,559	45,624	43,829	57,668	723	1,715
Delaware	8,243	2,499	2,843	2,863	36	2
Maryland	55,084	21,047	23,917	9,498	274	348
District of Columbia	10,418	1,643	8,146	249	97	282
Virginia	81,104	29,679	24,744	17,086	308	9,286
West Virginia	26,998	9,362	6,428	11,119	71	18
North Carolina	88,495	29,352	27,415	30,109	328	1,291
South Carolina	48,111	13,540	12,195	21,710	116	549
Georgia	74,685	20,984	25,003	28,014	399	285
Florida	143,974	72,082	54,587	12,513	501	4,292
South Atlantic	537,112	200,188	185,279	133,160	2,131	16,355
Kentucky	44,029	12,265	9,173	19,636	152	2,803
Tennessee	1,804	662	364	732	8	39
Alabama	50,157	15,699	12,314	21,943	198	3
Mississippi	22,061	7,002	7,003	7,653	114	289
East South Central	118,052	35,628	28,854	49,964	472	3,135
Arkansas	24,758	8,060	6,394	9,859	121	323
Louisiana	67,620	19,993	14,660	30,446	323	2,198
Oklahoma	35,486	12,328	9,872	10,694	117	2,475
Texas	238,233	77,604	64,318	86,683	915	8,713
West South Central	366,097	117,986	95,244	137,682	1,476	13,709
Montana	6,056	2,054	2,412	1,464	43	84
Idaho	19,276	5,588	5,815	7,833	37	2
Wyoming	8,488	1,159	1,489	5,762	20	59
Colorado	24,855	7,537	11,998	5,018	172	130
New Mexico	12,663	3,434	4,429	4,079	87	635
Arizona	31,443	12,065	11,180	7,770	124	304
Utah	17,846	4,747	5,549	7,024	58	469
Nevada	23,320	7,870	5,563	9,152	149	586
Mountain	143,947	44,454	48,435	48,101	689	2,267
Washington	30,287	13,434	10,766	5,973	102	13
Oregon	33,591	12,680	11,721	9,043	146	-
California	153,524	58,419	60,111	33,617	874	503
Pacific	217,401	84,533	82,597	48,633	1,122	516
Alaska	441	169	133	57	1	80
Hawaii	9,381	2,689	2,887	3,748	57	-
Alaska & Hawaii	9,822	2,858	3,020	3,805	58	80

Note: Total may not equal sum of components due to independent rounding.
Source: U.S. Department of Energy. Energy Information Administration. *Annual Electric Utility Report (EIA-861).*

TABLE 43
Energy Sales
Total Electric Utility Industry
By Quarter and Class of Service
1993-1999 - Gigawatthours

Year-Quarter	Total to Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Sales*	Railroads and Railways	Inter-departmental
YEAR-1993								
First Quarter.	695,964	256,905	189,039	224,191	4,665	19,102	1,458	596
Second Quarter. . . .	668,791	211,788	192,176	239,610	4,299	18,587	1,380	645
Third Quarter.	791,800	291,337	227,283	251,239	4,324	16,164	1,115	738
Fourth Quarter.	693,200	234,114	194,596	241,571	4,847	15,832	1,424	732
Total.	2,849,755	994,144	803,094	958,611	18,134	69,685	5,376	2,711
YEAR-1994								
First Quarter.	719,796	267,325	196,814	231,218	4,536	17,703	1,569	631
Second Quarter. . . .	692,927	220,834	202,239	245,480	4,355	17,824	1,486	708
Third Quarter.	806,095	288,665	234,333	260,833	4,402	15,789	1,200	873
Fourth Quarter.	711,244	231,668	200,122	252,724	5,169	19,256	1,533	772
Total.	2,930,063	1,008,492	833,508	990,254	18,462	70,572	5,788	2,985
YEAR-1995								
First Quarter.	723,517	262,080	199,573	239,704	4,195	16,315	1,429	221
Second Quarter. . . .	702,938	222,001	206,067	251,193	4,334	17,415	1,316	613
Third Quarter.	848,036	313,033	247,928	261,977	4,401	18,920	1,146	631
Fourth Quarter.	732,978	245,285	209,934	253,304	4,958	17,278	1,590	629
Total.	3,007,469	1,042,399	863,501	1,006,178	17,887	69,929	5,481	2,094
YEAR-1996								
First Quarter.	773,128	290,273	212,302	246,991	4,544	17,032	1,482	504
Second Quarter. . . .	735,893	240,120	214,268	258,071	4,422	17,083	1,275	654
Third Quarter.	838,749	301,108	244,760	267,606	4,263	18,953	1,295	763
Fourth Quarter.	746,214	250,856	215,756	255,760	4,809	17,230	1,250	553
Total.	3,093,984	1,082,358	887,086	1,028,427	18,037	70,299	5,302	2,475
YEAR-1997								
First Quarter.	765,451	278,342	217,018	244,961	4,785	18,005	1,580	645
Second Quarter. . . .	728,977	227,505	220,157	256,315	4,925	18,014	1,322	643
Third Quarter.	869,698	312,064	261,907	268,508	4,959	20,605	1,161	719
Fourth Quarter.	774,478	260,693	229,949	257,883	5,070	19,000	1,258	610
Total.	3,138,604	1,078,605	929,031	1,027,667	19,739	75,623	5,321	2,617
YEAR-1998r								
First Quarter.	768,015	274,497	221,037	248,013	4,090	20,379	N/A	N/A
Second Quarter. . . .	771,132	249,568	234,864	261,729	3,738	21,238	N/A	N/A
Third Quarter.	923,121	347,783	277,586	269,742	4,183	23,828	N/A	N/A
Fourth Quarter.	777,551	255,890	235,042	260,555	4,279	21,784	N/A	N/A
Total.	3,239,818	1,127,735	968,528	1,040,038	16,288	87,229	N/A	N/A
YEAR-1999								
First Quarter.	779,218	286,628	225,600	241,630	3,776	21,584	N/A	N/A
Second Quarter. . . .	768,078	249,904	235,903	256,369	3,856	22,044	N/A	N/A
Third Quarter.	920,397	349,259	276,422	265,614	4,333	24,769	N/A	N/A
Fourth Quarter.	768,208	254,970	232,676	254,170	3,929	22,463	N/A	N/A
Total.	3,235,899	1,140,761	970,601	1,017,783	15,894	90,860	N/A	N/A

Note: Total may not equal sum of components due to independent rounding.
r Revised.
N/A = Not available.
** Beginning with 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in Other Sales.*

TABLE 44

Energy Sales

Investor-Owned Electric Utilities

By Quarter and Class of Service

1993-1999 - Gigawatthours

Year-Quarter	Total to Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Sales*	Railroads and Railways	Inter-depart-mental
YEAR-1993								
First Quarter. . . .	536,035	187,947	157,024	178,195	2,848	11,135	656	187
Second Quarter. .	510,077	152,320	158,639	184,255	2,509	11,301	617	218
Third Quarter. . . .	600,446	208,144	187,764	189,171	2,558	12,295	584	277
Fourth Quarter. . .	528,623	169,074	160,438	183,860	2,907	11,431	591	178
Total.	2,175,181	717,485	663,865	733,482	10,822	46,162	2,447	860
YEAR-1994								
First Quarter. . . .	549,882	193,077	163,620	178,312	2,721	11,206	733	213
Second Quarter. .	530,725	159,113	168,765	187,730	2,579	11,612	681	265
Third Quarter. . . .	614,457	206,762	194,655	197,155	2,631	12,261	676	318
Fourth Quarter. . .	538,165	165,892	166,582	190,384	2,832	11,590	654	231
Total.	2,233,229	724,843	693,622	753,580	10,763	46,669	2,724	1,027
YEAR-1995								
First Quarter. . . .	551,843	188,716	165,537	182,479	2,720	11,600	692	99
Second Quarter. .	535,885	160,383	170,452	190,057	2,478	11,802	568	146
Third Quarter. . . .	643,068	225,142	204,705	198,761	2,518	13,187	649	105
Fourth Quarter. . .	555,573	176,638	173,442	190,327	2,945	11,481	622	120
Total.	2,286,370	750,878	714,136	759,624	10,661	48,069	2,531	470
YEAR-1996								
First Quarter. . . .	582,243	206,698	175,015	185,408	2,987	11,282	708	145
Second Quarter. .	556,366	170,985	176,636	193,725	2,907	11,316	609	188
Third Quarter. . . .	633,262	214,413	201,772	200,882	2,802	12,555	619	219
Fourth Quarter. . .	563,812	178,630	177,862	191,990	3,161	11,413	597	159
Total.	2,335,683	770,726	731,286	772,006	11,857	46,566	2,532	710
YEAR-1997								
First Quarter. . . .	578,636	197,705	176,098	189,402	2,742	11,916	641	131
Second Quarter. .	555,391	164,101	178,449	197,665	2,748	11,738	590	101
Third Quarter. . . .	651,584	220,631	209,393	204,498	2,861	13,546	557	99
Fourth Quarter. . .	583,677	185,093	184,060	198,393	2,967	12,491	571	102
Total.	2,369,288	767,530	748,000	789,958	11,319	49,692	2,357	432
YEAR-1998r								
First Quarter. . . .	574,768	193,061	176,692	189,811	3,048	12,159	N/A	N/A
Second Quarter. .	581,017	177,040	186,875	201,231	2,711	13,159	N/A	N/A
Third Quarter. . . .	687,853	243,922	220,224	206,233	2,679	14,795	N/A	N/A
Fourth Quarter. . .	584,095	182,244	186,721	198,696	2,846	13,588	N/A	N/A
Total.	2,427,733	796,267	770,512	795,971	11,282	53,701	N/A	N/A
YEAR-1999								
First Quarter. . . .	567,666	194,653	175,179	182,852	2,801	12,181	N/A	N/A
Second Quarter. .	573,303	178,500	185,274	193,853	2,493	13,183	N/A	N/A
Third Quarter. . . .	680,229	245,934	218,338	196,673	2,463	14,821	N/A	N/A
Fourth Quarter. . .	576,509	183,747	185,122	191,411	2,617	13,612	N/A	N/A
Total.	2,397,707	802,834	763,913	766,789	10,374	53,797	N/A	N/A

N/A = Not available.

Note: Total may not equal sum of components due to independent rounding.

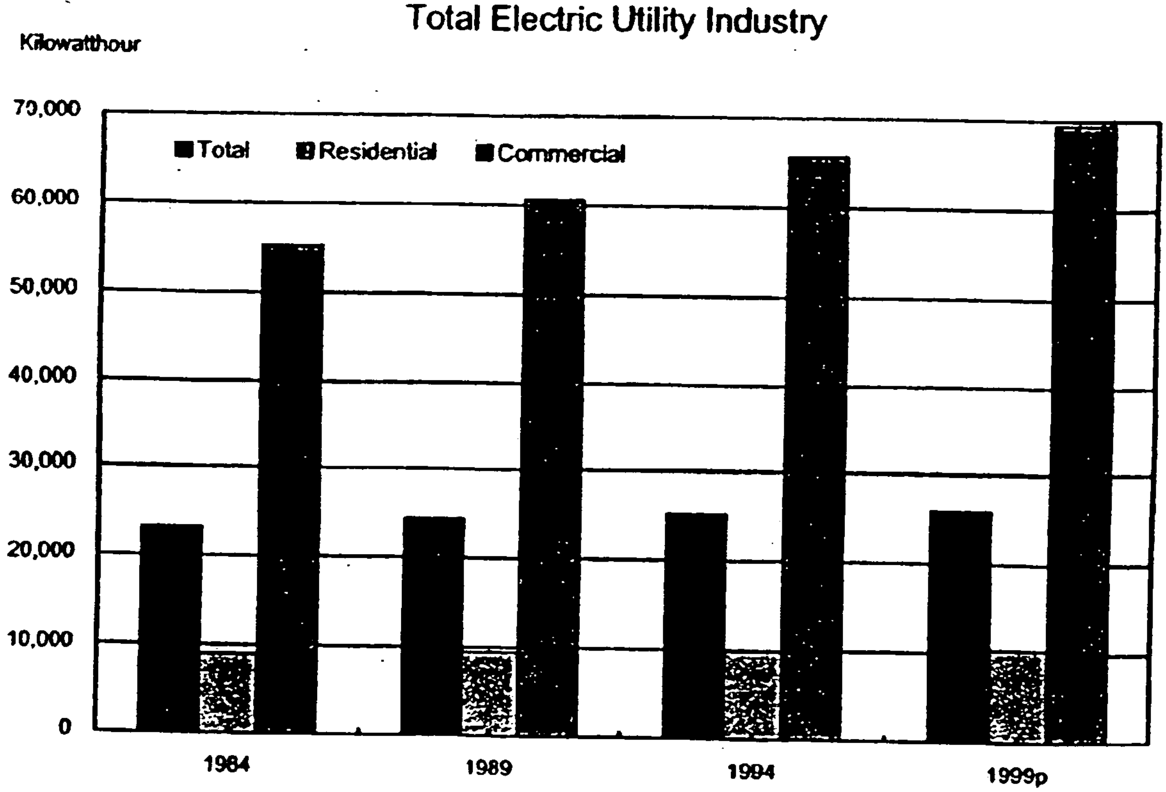
** Beginning with 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in Other Sales.*

TABLE 45
Average Annual kWh Use Per Customer

Total Electric Utility Industry					Investor-Owned Electric Utilities				
Year	Total Ultimate Customers	Residential	Commercial	Industrial	Year	Total Ultimate Customers	Residential	Commercial	Industrial
1979. .	23,481	8,843	53,197	N/A	1979. .	23,287	8,360	54,594	N/A
1980. .	23,167	9,025	54,538	N/A	1980. .	22,949	8,539	55,210	N/A
1981. .	23,026	8,825	53,402	1,669,211	1981. .	22,753	8,311	55,742	N/A
1982. .	22,197	8,743	52,260	1,431,408	1982. .	21,940	8,261	56,379	1,512,487
1983. .	22,479	8,814	53,822	1,567,077	1983. .	22,293	8,379	57,003	1,534,956
1984. .	23,152	8,978	55,205	1,661,280	1984. .	23,173	8,500	59,270	1,622,100
1985. .	22,903	8,906	56,109	1,598,675	1985. .	23,149	8,487	60,517	1,699,809
1986. .	23,071	9,090	57,161	1,625,242	1986. .	23,201	8,627	61,462	1,728,461
1987. .	23,472	9,236	58,409	1,719,914	1987. .	23,653	8,818	62,801	1,813,588
1988. .	24,167	9,498	60,437	1,784,084	1988. .	24,325	9,082	64,748	1,862,303
1989. .	24,359	9,470	60,576	1,793,286	1989. .	24,543	9,063	65,212	1,868,875
1990. .	24,551	9,508	61,277	1,793,467	1990. .	24,627	9,058	65,796	1,827,987
1991. .	24,691	9,719	61,565	1,779,766	1991. .	24,798	9,280	66,560	1,809,554
1992. .	24,350	9,392	61,022	1,747,274	1992. .	24,530	8,949	65,998	1,820,737
1993. .	24,870	9,864	64,424	1,758,234	1993. .	25,090	9,394	69,470	1,877,728
1994. .	25,190	9,868	65,658	1,703,065	1994. .	25,423	9,378	71,352	1,874,409
1995. .	25,448	10,042	66,821	1,757,621	1995. .	25,666	9,583	72,181	1,930,088
1996. .	25,784	10,275	67,250	1,757,938	1996. .	25,875	9,713	72,575	1,922,512
1997. .	25,694	10,072	68,679	1,825,789	1997. .	25,905	9,552	72,697	1,961,108
1998r. .	26,119	10,371	70,017	1,932,558	1998r. .	26,420	9,875	74,120	1,977,004
1999p. .	25,837	10,388	69,508	1,930,072	1999p. .	25,947	9,897	73,214	1,970,148

Based on sales data in Tables 38 and 39, and customer data in tables 47 and 48. N/A Not Available. r Revised. p Preliminary.

Chart VI-D
Average Kilowatthours Used
Total Electric Utility Industry



Based on Table 45, as shown above.

SECTION VII
CUSTOMERS

TABLE 47
Ultimate Customers
Total Electric Utility Industry
Average- By Year and Class of Service+

Year	Total Ultimate Customers	Residential	Commercial*	Industrial*	Street and Highway Lighting	Other Customers **	Railroads and Railways	Inter-depart-mental
1979.	89,771,985	79,620,180	9,388,572	477,874	124,228	158,098	30	5,003
1980.	92,653,471	82,153,162	9,698,809	484,652	142,724	168,120	30	5,974
1981.	94,011,299	83,304,355	9,847,260	518,996	141,051	197,187	31	4,419
1982.	95,250,268	84,371,779	9,976,274	533,635	148,678	218,975	31	2,896
1983.	96,985,531	85,842,195	10,266,449	500,215	153,659	219,879	31	3,103
1984.	99,371,026	87,938,995	10,565,239	525,692	139,703	199,393	29	1,975
1985.	101,579,271	89,819,726	10,920,861	499,728	158,307	178,759	28	1,862
1986.	102,952,793	90,994,586	11,114,300	498,254	161,377	182,257	28	1,991
1987.	104,624,233	92,399,323	11,386,008	487,572	165,188	184,369	27	1,746
1988.	106,411,256	93,921,875	11,637,444	491,292	169,792	188,954	28	1,871
1989.	108,468,242	95,616,026	11,976,449	506,597	176,215	190,954	28	1,973
1990.	110,102,079	97,033,887	12,135,373	508,145	198,444	222,898	29	2,303
1991.	111,434,108	98,184,250	12,288,449	513,727	211,439	233,916	29	2,298
1992.	113,080,193	99,635,244	12,461,309	529,701	212,328	239,048	29	2,534
1993.	115,216,208	101,307,528	12,533,045	538,458	429,361	399,574	29	10,213
1994.	116,907,312	102,729,353	12,763,940	567,801	431,167	403,974	108	10,869
1995+.	118,180,005	103,804,131	12,922,598	572,466	447,461	423,310	116	9,923
1996+.	119,995,213	105,334,712	13,190,904	585,019	447,667	425,319	144	11,448
1997+.	122,154,887	107,093,501	13,527,117	562,862	407,020	553,167	145	11,075
1998r+. . . .	124,040,512	108,736,845	13,832,662	538,167	368,028	564,810	N/A	N/A
1999+.	125,242,583	109,817,057	13,963,937	527,329	380,968	553,292	N/A	N/A

+Beginning in 1995, ultimate customers are yearly average customers, not as of December 31 (year end). r Revised. N/A Not Available.
**Commercial and industrial are not wholly comparable on a year-to-year basis due to changes from one classification to another.*
***Beginning in 1998, data for Other Public Authorities, Railroads and Railways, and Interdepartmental are all combined in the "Other Customers" column.*
Sources: Edison Electric Institute and U.S. Department of Energy, Energy Information Administration, Annual Electric Utility Report (EIA-861).

TABLE 48

Ultimate Customers
Investor-Owned Electric Utilities

Average- By Year and Class of Service+

Year	Total Ultimate Customers	Residential	Commercial *	Industrial *	Street and Highway Lighting	Other Customers **	Railroads and Railways	Inter-depart-mental
1979. . . .	69,581,540	61,676,402	7,290,125	372,407	108,149	134,171	23	232
1980. . . .	70,996,563	62,902,588	7,459,959	375,540	123,589	134,595	23	263
1981. . . .	72,037,264	63,820,699	7,579,344	389,646	112,061	135,049	23	269
1982. . . .	72,979,298	64,648,932	7,702,142	378,016	113,251	136,484	23	442
1983. . . .	74,247,765	65,718,130	7,886,857	387,875	115,170	139,233	23	450
1984. . . .	75,709,055	66,987,481	8,066,025	396,304	117,874	140,907	23	477
1985. . . .	77,203,821	68,234,704	8,340,862	363,757	121,395	142,621	23	441
1986. . . .	78,717,500	69,548,070	8,535,188	364,294	123,525	145,957	22	460
1987. . . .	80,232,499	70,826,711	8,768,207	360,468	127,644	149,022	22	444
1988. . . .	81,673,876	72,036,602	8,985,299	367,854	131,711	151,898	21	426
1989. . . .	83,029,027	73,177,333	9,181,076	376,790	137,579	155,770	22	490
1990. . . .	84,240,074	74,223,521	9,332,439	383,418	140,521	158,689	22	457
1991. . . .	85,138,027	75,037,580	9,395,616	386,270	147,289	170,785	23	463
1992. . . .	86,221,811	75,985,426	9,522,074	384,088	146,301	173,414	23	464
1993. . . .	87,324,291	76,895,776	9,623,413	383,005	238,823	182,792	23	485
1994. . . .	88,433,759	77,824,272	9,790,478	388,383	240,467	189,471	23	459
1995+. . . .	89,081,691	78,354,056	9,893,634	393,570	243,764	196,180	87	501
1996+. . . .	90,267,307	79,349,510	10,076,313	401,561	251,470	187,928	77	385
1997+. . . .	91,459,782	80,350,086	10,251,253	402,812	256,813	198,600	97	121
1998r+. . .	91,889,360	80,630,612	10,395,516	402,615	257,399	203,218	N/A	N/A
1999+. . . .	92,408,587	81,115,934	10,433,991	389,204	255,995	213,463	N/A	N/A

+Beginning in 1995, ultimate customers are yearly average customers, not as of December 31 (year end). r Revised. N/A Not Available.
**Commercial and industrial are not wholly comparable on a year-to-year basis due to changes from one classification to another.*
*** Beginning in 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are combined in the "Other Customers" column.*
Sources: Edison Electric Institute and U.S. Department of Energy, Energy Information Administration, Annual Electric Utility Report. (EIA-861).

TABLE 49
Customers in Percent of Total
Total Electric Utility Industry
Average- By Year and Class of Service+

Year	Residential	Commercial	Industrial	Street and Highway Lighting	Other Customers*	Railroads and Railways**	Inter-depart-mental**
1979.	88.7	10.5	0.5	0.1	0.2	0.0	0.0
1980.	88.7	10.5	0.5	0.1	0.2	0.0	0.0
1981.	88.6	10.5	0.5	0.2	0.2	0.0	0.0
1982.	88.6	10.5	0.6	0.1	0.2	0.0	0.0
1983.	88.5	10.6	0.5	0.2	0.2	0.0	0.0
1984.	88.5	10.6	0.5	0.2	0.2	0.0	0.0
1985.	88.3	10.8	0.5	0.2	0.2	0.0	0.0
1986.	88.3	10.8	0.5	0.2	0.2	0.0	0.0
1987.	88.3	10.8	0.5	0.2	0.2	0.0	0.0
1988.	88.2	10.9	0.5	0.2	0.2	0.0	0.0
1989.	88.2	10.9	0.5	0.2	0.2	0.0	0.0
1990.	88.1	11.0	0.5	0.2	0.2	0.0	0.0
1991.	88.1	11.0	0.5	0.2	0.2	0.0	0.0
1992.	88.1	11.0	0.5	0.2	0.2	0.0	0.0
1993.	87.9	10.9	0.5	0.4	0.3	0.0	0.0
1994.	87.9	10.9	0.5	0.4	0.3	0.0	0.0
1995+.	87.8	10.9	0.5	0.4	0.4	0.0	0.0
1996+.	87.8	10.9	0.5	0.4	0.4	0.0	0.0
1997+.	87.7	11.1	0.5	0.3	0.5	0.0	0.0
1998r+.	87.7	11.2	0.4	0.3	0.5	N/A	N/A
1999+.	87.7	11.1	0.4	0.3	0.4	N/A	N/A

Note: Total may not sum to 100.0% due to independent rounding. r Revised. N/A Not Available.
+Beginning in 1995, ultimate customers are yearly average customers, not as of December 31 (year end).
** Beginning in 1998, data for Other Public Authorities, Railroads and Railways, and Interdepartmental are all combined in the "Other Customers" column.*
*** Less than one-tenth of one percent.*
Based on customer data in Table 47.

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TABLE 50

Ultimate Customers
Total Electric Utility Industry

Average- By State and Class of Service - Year 1999

State/Division	Total Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Customers
Total United States	**125,242,583**	**109,817,057**	**13,963,937**	**527,329**	**380,968**	**553,292**
Maine	723,516	625,988	78,264	2,676	17,958	630
New Hampshire	823,962	531,875	83,245	3,302	4,895	645
Vermont	322,197	280,314	40,164	440	724	555
Massachusetts	2,827,093	2,495,675	306,208	13,871	6,989	4,350
Rhode Island	467,794	419,188	45,393	2,498	689	26
Connecticut	1,503,282	1,361,589	130,813	5,916	3,294	1,670
New England	**6,467,844**	**5,714,629**	**682,087**	**28,703**	**34,549**	**7,878**
New York	7,499,171	6,601,592	855,942	8,536	13,125	19,976
New Jersey	3,605,476	3,147,864	433,754	13,060	10,743	55
Pennsylvania	5,104,483	4,562,445	510,258	23,901	5,691	2,188
Middle Atlantic	**16,209,130**	**14,311,901**	**1,799,954**	**45,497**	**29,559**	**22,219**
Ohio	5,197,242	4,630,054	517,069	29,990	7,690	12,439
Indiana	2,816,941	2,505,377	284,254	18,309	6,286	2,715
Illinois	5,139,907	4,622,423	481,254	5,390	4,413	26,427
Michigan	4,534,231	4,058,091	450,752	13,515	6,554	5,319
Wisconsin	2,571,264	2,282,906	271,363	5,367	5,502	6,126
East North Central	**20,259,585**	**18,098,851**	**2,004,692**	**72,571**	**30,445**	**53,026**
Minnesota	2,275,795	2,017,362	224,404	11,067	6,242	16,720
Iowa	1,416,687	1,228,606	167,576	3,971	2,253	14,281
Missouri	2,736,945	2,405,251	308,178	9,590	3,332	10,594
North Dakota	341,197	286,494	47,679	1,859	894	4,271
South Dakota	379,689	318,578	50,131	1,884	1,296	7,800
Nebraska	885,715	718,240	117,810	8,421	3,178	38,066
Kansas	1,330,034	1,118,271	180,990	13,781	2,593	14,399
West North Central	**9,366,062**	**8,092,802**	**1,096,768**	**50,573**	**19,788**	**106,131**
Delaware	370,500	331,047	37,983	551	726	193
Maryland	2,174,889	1,952,497	213,306	7,633	1,279	174
District of Columbia	219,923	193,822	26,069	1	30	1
Virginia	3,062,559	2,715,550	299,282	5,284	3,236	39,207
West Virginia	943,913	813,330	116,154	11,201	1,305	1,923
North Carolina	4,006,103	3,474,399	500,602	12,771	11,696	6,635
South Carolina	2,012,085	1,724,911	266,724	4,900	6,959	8,591
Georgia	3,732,145	3,295,924	392,919	10,987	10,433	21,882
Florida	7,961,361	7,001,021	862,939	23,353	25,798	48,250
South Atlantic	**24,483,478**	**21,502,501**	**2,715,978**	**76,681**	**61,462**	**126 856**
Kentucky	1,991,347	1,734,903	227,020	6,883	9,355	13,186
Tennessee	2,747,901	2,363,365	370,445	1,758	12,237	96
Alabama	2,224,999	1,900,692	304,125	6,378	4,362	9,442
Mississippi	1,345,963	1,152,329	179,959	4,504	2,183	6,988
East South Central	**8,310,210**	**7,151,289**	**1,081,549**	**19,523**	**28,137**	**29,712**
Arkansas	1,339,280	1,159,684	139,604	25,771	1,685	12,536
Louisiana	2,041,874	1,791,240	213,273	15,419	2,541	19,401
Oklahoma	1,729,389	1,495,399	203,523	15,334	2,413	12,720
Texas	9,032,925	7,832,319	1,040,684	65,431	11,966	82,525
West South Central	**14,143,488**	**12,278,642**	**1,597,084**	**121,955**	**18,605**	**127,182**
Montana	480,628	393,329	69,060	4,254	3,854	10,131
Idaho	617,058	516,526	90,798	6,566	511	2,657
Wyoming	271,125	218,808	45,501	3,805	731	2,280
Colorado	2,047,712	1,712,891	235,962	2,787	85,218	10,854
New Mexico	826,832	712,084	102,233	6,165	984	5,368
Arizona	2,121,707	1,896,943	200,359	5,136	11,096	8,173
Utah	833,806	738,880	80,840	8,731	3,547	1,808
Nevada	870,800	760,262	108,077	1,358	392	711
Mountain	**8,069,668**	**6,949,723**	**932,830**	**38,802**	**106,333**	**41,980**
Washington	2,707,232	2,390,364	272,983	19,386	8,164	16,335
Oregon	1,635,114	1,408,927	203,161	11,850	2,037	9,139
California	12,899,380	11,326,501	1,487,329	40,654	36,678	8,218
Pacific	**17,241,728**	**15,125,792**	**1,963,473**	**71,890**	**46,879**	**33,692**
Alaska	269,831	227,247	36,536	473	957	4,618
Hawaii	421,581	363,680	52,986	661	4,254	-
Alaska & Hawaii	**691,412**	**590,927**	**89,522**	**1,134**	**5,211**	**4,618**

Note: Customers for Street and Highway Lighting, and Other Customers may reflect the number of meters or connections instead of actual customers.

Source: U.S. Department of Energy. Energy Information Administration. Annual Electric Utility Report (EIA-861).

TABLE 51
Ultimate Customers
Investor-Owned Electric Utilities
Average- By State and Class of Service - Year 1999

State/Division	Total Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Customers
Total United States	**92,408,587**	**81,115,934**	**10,433,991**	**389,204**	**255,995**	**213,463**
Maine	695,022	602,161	72,625	2,516	17,713	7
New Hampshire	542,784	463,446	72,814	3,244	2,629	631
Vermont	247,095	214,036	32,402	72	267	318
Massachusetts	2,459,487	2,173,333	272,914	7,785	5,454	1
Rhode Island	463,751	415,483	45,078	2,477	688	25
Connecticut	1,436,491	1,304,991	121,803	5,734	2,777	1,186
New England	**5,844,610**	**5,173,450**	**617,638**	**21,828**	**29,528**	**2,168**
New York	6,269,541	5,507,926	729,651	7,137	8,084	16,743
New Jersey	3,540,274	3,089,881	426,943	12,955	10,494	1
Pennsylvania	4,824,355	4,305,720	489,793	23,201	5,359	282
Middle Atlantic	**14,634,170**	**12,903,527**	**1,646,387**	**43,293**	**23,937**	**17,026**
Ohio	4,509,578	4,011,171	455,745	27,741	7,281	7,640
Indiana	2,112,116	1,861,861	231,068	14,732	3,810	645
Illinois	4,649,503	4,180,697	441,410	3,233	552	23,611
Michigan	3,994,111	3,581,054	398,994	11,447	3,398	1,220
Wisconsin	2,122,833	1,883,082	230,957	3,590	4,569	635
East North Central	**17,388,141**	**15,517,865**	**1,758,174**	**60,743**	**19,608**	**33,751**
Minnesota	1,352,560	1,185,159	153,176	8,275	3,032	2,918
Iowa	1,030,060	883,157	133,448	2,540	1,004	9,911
Missouri	1,751,194	1,524,032	213,860	7,198	2,400	3,704
North Dakota	211,133	175,968	33,402	759	405	599
South Dakota	203,436	168,201	33,544	543	566	582
Nebraska	-	-	-	-	-	-
Kansas	902,528	787,033	108,678	6,357	238	222
West North Central	**5,450,911**	**4,723,550**	**676,108**	**25,672**	**7,645**	**17,936**
Delaware	264,269	236,299	27,341	308	320	1
Maryland	1,986,771	1,782,119	196,459	7,344	846	3
District of Columbia	219,923	193,822	26,069	1	30	1
Virginia	2,543,417	2,250,681	256,912	4,168	2,451	29,205
West Virginia	931,792	803,404	114,718	11,193	1,294	1,183
North Carolina	2,691,092	2,291,419	376,716	10,870	10,244	1,843
South Carolina	1,166,013	982,055	174,295	3,863	3,466	2,334
Georgia	1,982,155	1,728,195	241,276	9,254	3,425	5
Florida	6,055,612	5,351,932	656,033	19,859	4,927	23,061
South Atlantic	**17,841,044**	**15,819,926**	**2,069,819**	**66,860**	**27,003**	**57,636**
Kentucky	1,113,081	950,884	142,218	4,529	5,675	9,775
Tennessee	44,255	39,144	4,742	202	125	42
Alabama	1,303,541	1,112,007	185,851	4,982	700	1
Mississippi	582,434	490,693	84,356	3,768	547	3,070
East South Central	**3,043,311**	**2,592,728**	**417,167**	**13,481**	**7,047**	**12,888**
Arkansas	798,825	678,151	94,935	23,342	566	1,831
Louisiana	1,564,091	1,366,599	167,754	14,476	2,263	12,999
Oklahoma	1,143,901	988,374	129,745	13,563	1,723	10,496
Texas	6,253,652	5,435,297	721,400	46,110	8,050	42,795
West South Central	**9,760,469**	**8,468,421**	**1,113,834**	**97,491**	**12,602**	**68,121**
Montana	320,186	261,246	51,752	3,512	3,510	166
Idaho	516,461	430,139	79,927	5,937	439	19
Wyoming	170,612	139,737	27,317	2,925	521	112
Colorado	1,275,002	1,052,831	138,017	381	83,677	96
New Mexico	579,073	507,473	66,627	3,030	539	1,404
Arizona	1,205,112	1,076,275	122,218	4,681	918	1,020
Utah	630,968	563,259	56,141	8,388	3,152	28
Nevada	822,915	720,374	101,203	1,169	115	54
Mountain	**5,520,329**	**4,751,334**	**643,202**	**30,023**	**92,871**	**2,899**
Washington	1,221,366	1,075,563	132,727	11,074	1,967	35
Oregon	1,217,448	1,049,155	156,275	10,764	1,254	-
California	10,040,653	8,856,944	1,147,939	7,413	28,270	87
Pacific	**12,479,467**	**10,981,662**	**1,436,941**	**29,251**	**31,491**	**122**
Alaska	24,554	19,791	3,737	101	9	916
Hawaii	421,581	363,680	52,986	661	4,254	-
Alaska & Hawaii	**446,135**	**383,471**	**56,723**	**762**	**4,263**	**916**

Note: Customers for Street and Highway Lighting, and Other Customers may reflect the number of meters or connections instead of actual customers.
Source: U.S. Department of Energy. Energy Information Administration. Annual Electric Utility Report (EIA-861).

TABLE 56

Revenues

Total Electric Utility Industry

By Year and Class of Service

Thousands of Dollars

Year	Total Revenue from Sales+	Exports to Canada and Mexico++	Total from Ultimate Customers	Residential	Commercial *	Industrial *	Street and Highway Lighting	Other Revenues**	Railroads and Railways	Interdepartmental
1979. .	$79,849,846	$9,609	$79,840,237	$30,798,693	$22,264,356	$23,825,487	$918,157	$1,517,333	$188,628	$127,583
1980. .	95,505,802	43,421	95,462,381	37,580,892	27,369,963	27,316,770	1,041,008	1,811,065	207,683	135,000
1981. .	111,028,011	26,838	111,001,173	42,824,457	31,325,322	33,030,093	1,168,691	2,247,307	238,554	166,749
1982. .	121,597,243	13,012	121,584,231	47,188,127	34,150,840	35,881,745	1,254,430	2,633,749	291,751	183,589
1983. .	129,596,675	7,874	129,588,801	51,226,246	37,103,377	38,611,630	1,324,955	2,864,037	296,766	161,790
1984. .	143,114,300	21,796	143,092,504	56,116,141	41,253,720	40,795,789	1,375,931	3,044,623	302,725	203,574
1985. .	149,187,568	25,218	149,162,352	58,591,751	44,060,554	41,367,847	1,478,092	3,163,473	313,165	189,470
1986. .	152,480,811	13,688	152,467,123	60,910,603	45,410,286	40,906,054	1,498,431	3,214,164	311,971	215,614
1987. .	155,733,643	33,407	155,700,236	63,049,059	46,745,107	40,630,608	1,509,248	3,273,260	301,635	191,321
1988. .	162,449,065	61,207	162,387,858	68,402,539	49,141,145	41,561,302	1,503,799	3,308,314	296,215	174,544
1989. .	169,903,112	276,332	169,626,780	68,760,042	51,561,710	43,745,803	1,544,298	3,518,362	328,974	167,591
1990. .	176,928,812	460,863	176,467,949	71,866,279	54,193,002	44,865,804	1,633,369	3,610,237	337,620	161,637
1991. .	185,220,296	102,631	185,117,665	76,350,757	56,847,134	45,869,777	1,689,600	3,894,210	338,050	128,137
1992. .	187,399,044	115,976	187,283,068	78,392,219	57,969,047	46,760,653	1,739,072	3,929,403	363,087	129,587
1993. .	197,991,799	134,547	197,857,252	82,438,503	62,040,225	48,591,203	2,031,192	4,229,446	382,505	146,178
1994. .	202,597,119	81,677	202,515,442	84,517,347	64,432,340	46,816,060	2,024,512	4,158,918	416,269	149,997
1995. .	207,651,577	93,058	207,558,519	87,597,523	66,477,471	46,913,380	1,962,316	4,122,624	378,718	108,486
1996. .	212,390,487	97,300	212,293,187	90,465,389	67,801,618	47,358,592	1,836,493	4,309,243	361,507	160,345
1997. .	215,264,141	117,091	215,147,050	90,881,203	70,458,832	46,690,273	2,184,639	4,428,541	376,108	127,454
1998. .	218,490,595	128,009	218,362,586	93,166,443	71,772,470	46,560,216	1,875,735	4,987,722	N/A	N/A
1999. .	215,647,371	174,544	215,472,827	93,142,367	70,492,058	45,055,529	1,809,785	4,973,088	N/A	N/A

+Excludes other electric revenues. ++Source: Department of Energy. Energy Information Administration. Annual Report of International Electric Import/Export Data (FE-781R).

Please see Table 57 for other notes.

TABLE 57

Revenues

Investor-Owned Electric Utilities

By Year and Class of Service

Thousands of Dollars

Year	Total Revenues	Other Revenues+	Total from Ultimate Customers	Residential	Commercial *	Industrial *	Street and Highway Lighting	Other Revenues**	Railroads and Railways	Interdepartmental
1979. .	$68,151,992	$4,274,055	$63,877,937	$23,613,621	$18,463,690	$19,801,718	$716,209	$1,137,987	$80,002	$64,710
1980. .	80,635,823	4,460,469	76,175,354	28,492,402	22,351,012	22,970,668	819,762	1,362,136	111,552	67,822
1981. .	94,266,325	5,497,327	88,768,998	32,622,129	26,370,929	26,986,678	933,861	1,641,632	120,124	93,645
1982. .	101,692,973	4,595,135	97,097,838	36,138,384	29,603,969	28,322,848	1,022,473	1,775,494	130,340	104,329
1983. .	109,446,384	6,581,164	102,865,220	39,067,481	31,336,661	29,275,314	1,057,872	1,899,057	126,300	102,538
1984. .	120,090,160	6,752,083	113,338,077	42,474,833	34,720,332	32,605,010	1,119,279	2,144,129	142,578	131,916
1985. .	125,547,432	6,711,160	118,836,272	44,651,261	37,241,520	33,204,216	1,159,701	2,285,783	157,728	136,064
1986. .	127,552,448	6,477,978	121,074,470	46,241,943	38,382,364	32,618,323	1,177,956	2,334,092	156,846	162,947
1987. .	129,437,054	6,124,194	123,312,860	47,962,072	39,437,160	32,110,727	1,196,413	2,320,698	147,338	136,454
1988. .	134,555,680	6,315,324	128,240,356	50,472,485	41,237,149	32,739,382	1,181,146	2,343,706	150,151	116,336
1989. .	140,883,099	7,005,070	133,878,029	52,325,314	43,440,937	34,132,516	1,212,529	2,499,378	158,725	108,631
1990. .	146,171,868	6,691,043	139,480,825	54,549,758	45,597,299	35,278,242	1,240,369	2,548,938	163,490	102,729
1991. .	153,903,744	6,660,684	147,243,060	58,560,848	48,129,655	36,158,888	1,284,624	2,854,065	177,900	77,081
1992. .	156,565,938	7,810,634	148,755,304	58,312,162	48,974,855	36,972,947	1,316,109	2,931,984	177,165	70,081
1993. .	162,318,898	6,018,042	156,300,856	62,658,939	52,385,777	38,594,605	1,429,027	2,990,518	169,517	72,473
1994. .	167,600,009	8,083,338	159,516,671	64,008,355	54,796,207	38,248,314	1,367,705	2,825,027	197,098	73,967
1995. .	172,680,719	9,046,502	163,634,217	66,596,508	56,285,488	38,298,167	1,330,924	2,909,831	175,949	37,350
1996. .	183,409,866	16,856,791	166,553,075	68,307,900	57,235,666	36,515,696	1,421,332	2,824,253	173,364	74,864
1997. .	194,653,613	26,083,409	168,570,204	68,587,739	58,493,914	36,940,321	1,416,458	2,929,311	172,639	29,822
1998. .	201,191,014	32,674,022	168,516,992	69,056,079	58,303,190	36,593,244	1,407,374	3,157,105	N/A	N/A
1999. .	195,517,065	31,852,075	163,664,990	68,275,866	56,287,443	34,747,270	1,303,800	3,050,611	N/A	N/A

+Includes revenue from sales to non-investor-owned electric utilities, from exports and other electric revenues.

Notes for both Table 56 and Table 57:

Total may not equal sum of components due to independent rounding. N/A Not Available.

* Commercial and Industrial are not wholly comparable on a year-to-year basis due to changes from one classification to another.

**Beginning in 1998, data for Other Public Authorities, Railroads and Railways, and Interdepartmental are all combined in the "Other Revenues" column.

Sources: Edison Electric Institute and U.S. Department of Energy. Energy Information Administration. Annual Electric Utility Report. (EIA-861).

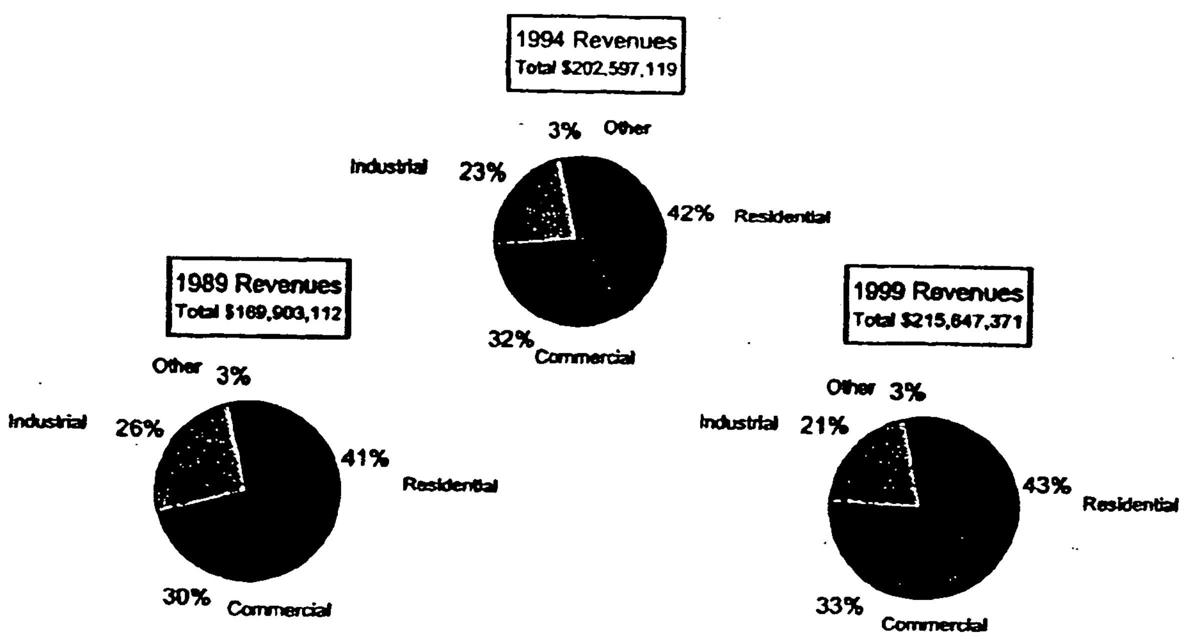
TABLE 58
Revenues in Percent of Total
Total Electric Utility Industry
By Year and Class of Service

Year	Residential	Commercial	Industrial	Street and Highway Lighting	Other Pub. Auth. / Other Sales	Railroads and Railways	Inter-depart-mental
1979	38.7	28.0	29.9	1.1	1.9	0.2	0.2
1980	39.4	28.7	28.6	1.1	1.9	0.2	0.1
1981	38.6	28.2	29.7	1.1	2.0	0.2	0.2
1982	38.8	28.1	29.5	1.0	2.2	0.2	0.2
1983	39.5	28.6	28.3	1.0	2.2	0.3	0.1
1984	39.3	28.8	28.5	1.0	2.1	0.2	0.1
1985	39.3	29.5	27.8	1.0	2.1	0.2	0.1
1986	40.0	29.8	26.8	1.0	2.1	0.2	0.1
1987	40.5	30.0	26.1	1.0	2.1	0.2	0.1
1988	40.9	30.3	25.6	0.9	2.0	0.2	0.1
1989	40.5	30.4	25.8	0.9	2.1	0.2	0.1
1990	40.7	30.7	25.4	0.9	2.0	0.2	0.1
1991	41.2	30.7	24.8	0.9	2.1	0.2	0.1
1992	40.8	31.0	25.0	0.9	2.1	0.2	0.1
1993	41.7	31.4	23.5	1.0	2.1	0.2	0.1
1994	41.7	31.8	23.1	1.0	2.1	0.2	0.1
1995	42.2	32.0	22.6	0.9	2.0	0.2	0.1
1996	42.6	31.9	22.3	0.9	2.0	0.2	0.1
1997	42.2	32.7	21.7	1.0	2.1	0.2	0.1
1998	42.7	32.9	21.3	0.9	2.3 **	N/A	N/A
1999	43.2	32.7	20.9	0.8	2.3 **	N/A	N/A

Based on revenue data in Table 56.

**Beginning in 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in the Other Public Authorities column as "Other Sales." N/A Not Available.*

Chart VIII-B
Revenues
Total Electric Utility Industry
by Year and Class of Service
Thousands of Dollars



Note: Total may not add to 100% due to independent rounding.

TABLE 59

Revenues

Total Electricity Utility Industry

By State and Class of Service

Year 1999 - Thousands of Dollars

State/Division	Total from Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Revenues
Total United States	**$215,472,827**	**$93,142,367**	**$70,492,058**	**$45,055,529**	**$1,809,785**	**$4,973,088**
Maine	1,167,145	484,235	366,983	300,998	14,062	867
New Hampshire	1,142,138	494,489	400,130	231,160	8,846	7,513
Vermont	568,267	243,174	202,441	116,673	3,785	2,194
Massachusetts	4,382,360	1,754,839	1,821,322	729,295	61,298	15,606
Rhode Island	600,056	269,654	229,166	84,012	7,408	9,816
Connecticut	2,968,057	1,331,601	1,147,003	433,167	26,517	29,769
New England	**10,828,023**	**4,577,992**	**4,167,045**	**1,895,305**	**121,916**	**65,765**
New York	13,503,004	5,665,031	5,522,906	1,202,549	161,400	951,118
New Jersey	7,054,224	2,797,622	3,160,077	1,005,072	89,794	1,659
Pennsylvania	7,362,814	3,789,617	1,958,762	1,508,290	67,708	38,437
Middle Atlantic	**27,920,042**	**12,252,270**	**10,641,745**	**3,715,911**	**318,902**	**991,214**
Ohio	10,516,499	4,045,743	3,025,175	3,213,686	63,380	168,515
Indiana	5,118,823	2,005,285	1,219,651	1,839,587	39,929	12,371
Illinois	9,225,563	3,500,292	3,095,070	2,087,756	16,917	525,528
Michigan	7,387,391	2,678,360	2,754,868	1,859,753	72,354	24,056
Wisconsin	3,514,798	1,425,681	1,036,965	999,326	31,496	21,328
East North Central	**35,761,072**	**13,653,361**	**11,131,729**	**10,000,108**	**224,076**	**751,798**
Minnesota	3,343,791	1,334,265	688,291	1,266,701	28,959	25,575
Iowa	2,254,954	991,100	533,486	642,276	20,372	67,720
Missouri	4,184,045	1,976,459	1,435,557	706,586	23,739	41,704
North Dakota	500,472	214,782	145,345	121,601	4,034	14,710
South Dakota	503,007	245,035	153,394	88,692	4,734	11,152
Nebraska	1,211,755	517,099	362,245	245,943	19,400	67,068
Kansas	2,102,264	867,435	738,912	457,057	18,307	20,553
West North Central	**14,100,288**	**6,146,175**	**4,057,230**	**3,528,858**	**119,545**	**248,482**
Delaware	746,909	323,774	247,563	168,424	5,836	1,312
Maryland	4,157,853	1,959,318	1,703,324	423,368	44,807	27,036
District of Columbia	776,523	131,395	608,812	11,439	3,584	21,293
Virginia	5,454,492	2,677,381	1,497,523	778,452	38,•30	463,006
West Virginia	1,382,944	593,022	358,303	423,248	7,016	1,355
North Carolina	7,411,703	3,486,165	2,221,310	1,560,387	48,267	95,574
South Carolina	4,085,478	1,790,295	1,045,120	1,196,059	13,802	40,202
Georgia	7,024,803	3,158,846	2,272,403	1,463,147	63,286	67,121
Florida	12,819,403	7,253,310	4,297,425	885,802	85,521	297,345
South Atlantic	**43,860,108**	**21,373,506**	**14,251,783**	**6,910,326**	**310,249**	**1,014,244**
Kentucky	3,298,834	1,257,441	696,494	1,195,898	24,589	124,412
Tennessee	5,241,811	2,246,612	1,586,422	1,318,701	87,680	2,396
Alabama	4,456,054	1,901,352	1,187,496	1,319,741	31,557	15,908
Mississippi	2,485,558	1,102,038	890,480	631,832	27,773	33,435
East South Central	**15,482,257**	**6,507,443**	**4,160,892**	**4,466,172**	**171,599**	**176,151**
Arkansas	2,261,531	1,042,900	487,564	687,903	12,867	30,297
Louisiana	4,550,226	1,881,756	1,158,708	1,337,720	33,091	138,951
Oklahoma	2,511,063	1,208,052	691,895	478,252	16,694	116,170
Texas	18,243,045	8,201,199	5,179,341	3,963,869	130,647	767,989
West South Central	**27,565,865**	**12,333,907**	**7,517,508**	**6,467,744**	**193,299**	**1,053,407**
Montana	607,246	248,557	192,204	145,273	7,034	14,178
Idaho	870,008	358,072	271,119	227,595	3,758	9,464
Wyoming	508,161	128,341	132,737	235,679	2,665	6,739
Colorado	2,414,525	968,893	953,802	418,659	38,242	38,929
New Mexico	1,184,403	400,587	443,119	251,874	11,027	77,796
Arizona	4,170,220	1,921,783	1,484,420	628,398	54,350	81,269
Utah	1,063,740	391,213	385,090	254,101	8,099	25,237
Nevada	1,555,643	597,709	402,593	517,603	9,272	28,466
Mountain	**12,371,948**	**5,015,155**	**4,265,084**	**2,677,182**	**132,447**	**282,078**
Washington	3,864,147	1,673,433	1,119,207	935,938	28,241	107,328
Oregon	2,288,908	1,038,068	736,939	480,685	16,784	14,432
California	19,791,632	7,978,446	7,855,607	3,551,883	160,657	245,039
Pacific	**25,942,687**	**10,689,947**	**9,711,753**	**4,968,506**	**205,682**	**368,799**
Alaska	517,414	208,179	219,482	61,735	4,868	23,150
Hawaii	1,123,125	384,432	367,807	363,684	7,202	-
Alaska & Hawaii	**1,640,539**	**592,611**	**587,289**	**425,419**	**12,070**	**23,150**

Note: Total may not equal sum of components due to independent rounding.

Sources: Edison Electric Institute and U.S. Department of Energy. Energy Information Administration. Annual Electric Utility Report. (EIA-861).

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DOE002-0330

TABLE 60
Revenues
Investor-Owned Electric Utilities
By State and Class of Service
Year 1999 - Thousands of Dollars

State/Division	Total Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Revenues
Total United States	**$163,684,990**	**$68,275,866**	**$56,287,443**	**$34,747,270**	**$1,303,800**	**$3,050,611**
Maine	1,130,074	470,398	362,205	283,423	13,684	364
New Hampshire	1,028,929	426,680	365,048	221,470	8,252	7,479
Vermont	470,541	194,887	174,574	97,704	2,906	470
Massachusetts	3,767,061	1,523,908	1,677,314	519,984	45,515	340
Rhode Island	596,333	267,342	228,742	83,073	7,385	9,791
Connecticut	2,831,020	1,285,820	1,106,975	392,110	24,171	21,944
New England	**9,823,958**	**4,169,835**	**3,914,858**	**1,597,764**	**101,913**	**40,388**
New York	10,372,996	4,498,791	4,451,299	1,079,615	86,831	256,460
New Jersey	6,960,003	2,752,379	3,129,110	988,510	88,649	1,355
Pennsylvania	7,053,796	3,576,477	1,899,562	1,474,089	67,260	36,407
Middle Atlantic	**24,386,794**	**10,827,647**	**9,479,971**	**3,542,214**	**242,740**	**294,222**
Ohio	9,540,434	3,563,937	2,805,641	2,955,996	54,763	160,097
Indiana	4,183,268	1,484,866	1,046,642	1,610,766	35,173	5,821
Illinois	8,492,505	3,081,126	2,907,415	1,977,896	14,563	511,705
Michigan	6,704,031	2,410,382	2,527,043	1,691,015	64,873	10,718
Wisconsin	2,968,217	1,156,340	921,823	846,104	26,065	15,885
East North Central	**31,888,455**	**11,696,651**	**10,208,564**	**9,081,577**	**195,437**	**704,226**
Minnesota	2,227,937	716,975	406,537	1,071,533	20,487	12,405
Iowa	1,705,879	683,147	424,598	525,720	18,084	54,130
Missouri	2,965,296	1,272,698	1,145,819	502,771	20,664	23,344
North Dakota	257,403	102,810	94,148	53,336	3,479	3,630
South Dakota	290,801	114,755	105,490	65,418	3,225	1,913
Nebraska	–	–	–	–	–	–
Kansas	1,477,435	606,704	547,748	305,664	15,982	1,337
West North Central	**8,924,551**	**3,497,089**	**2,724,340**	**2,524,442**	**81,921**	**96,759**
Delaware	571,874	232,446	203,552	130,710	5,105	61
Maryland	3,858,529	1,770,980	1,627,525	399,043	43,313	17,668
District of Columbia	776,523	131,395	608,812	11,439	3,584	21,293
Virginia	4,666,015	2,199,537	1,350,067	640,796	33,916	441,699
West Virginia	1,371,432	585,593	355,064	422,820	6,946	1,009
North Carolina	5,325,128	2,235,812	1,639,944	1,349,042	36,315	64,013
South Carolina	2,630,163	1,014,036	748,497	829,376	11,356	26,898
Georgia	4,367,892	1,520,488	1,615,241	1,174,949	43,208	14,006
Florida	9,843,204	5,592,957	3,359,928	581,974	63,521	244,824
South Atlantic	**33,410,758**	**15,283,244**	**11,508,630**	**5,540,149**	**247,264**	**831,471**
Kentucky	1,773,251	628,607	450,496	563,352	14,821	115,975
Tennessee	79,430	32,747	18,233	25,553	1,139	1,758
Alabama	2,811,117	1,145,646	807,098	843,090	15,112	171
Mississippi	1,206,554	470,948	404,865	302,904	11,907	15,930
East South Central	**5,870,352**	**2,277,948**	**1,680,692**	**1,734,899**	**42,979**	**133,834**
Arkansas	1,449,022	626,730	360,336	436,061	11,114	14,781
Louisiana	3,831,613	1,427,841	962,711	1,280,919	30,494	129,648
Oklahoma	1,802,642	780,768	523,150	375,321	11,583	111,820
Texas	14,166,874	5,982,296	4,176,421	3,358,353	110,404	539,400
West South Central	**21,250,151**	**8,817,635**	**6,022,618**	**5,450,854**	**163,595**	**795,649**
Montana	370,412	145,041	156,625	58,451	6,463	3,832
Idaho	747,274	292,357	239,556	211,864	3,397	100
Wyoming	338,540	71,547	76,422	185,963	2,159	2,449
Colorado	1,463,023	564,614	649,925	213,218	29,192	6,074
New Mexico	836,401	287,128	331,864	172,324	8,831	36,254
Arizona	2,495,003	1,108,875	915,509	433,718	14,033	22,868
Utah	826,839	293,338	282,076	229,484	6,429	15,512
Nevada	1,447,188	567,763	377,103	471,077	9,053	22,192
Mountain	**8,524,680**	**3,330,663**	**3,029,080**	**1,976,099**	**79,557**	**109,281**
Washington	1,695,513	792,616	641,579	246,866	13,853	599
Oregon	1,718,007	763,242	592,622	347,513	14,630	–
California	14,998,724	6,415,341	6,096,284	2,337,140	112,474	37,485
Pacific	**18,412,244**	**7,971,199**	**7,330,485**	**2,931,519**	**140,957**	**38,084**
Alaska	51,922	20,323	20,398	4,269	235	6,697
Hawaii	1,123,125	384,432	367,807	363,684	7,202	–
Alaska & Hawaii	**1,175,047**	**404,755**	**388,205**	**367,953**	**7,437**	**6,697**

Note: Total may not equal sum of components due to independent rounding.

TABLE 63

Average Revenues Per Kilowatthour Sold
Total Electric Utility Industry

Cents Per Kilowatthour

Year	Total Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Revenues*	Railroads and Railways
1979.	3.82	4.43	4.50	2.91	6.21	3.06	4.43
1980.	4.49	5.12	5.22	3.44	7.02	3.75	4.86
1981.	5.16	5.86	6.00	4.03	7.96	4.18	5.67
1982.	5.79	6.44	6.61	4.66	8.81	4.72	6.80
1983.	6.00	6.83	6.80	4.68	9.50	5.00	6.90
1984.	6.27	7.17	7.14	4.88	9.69	5.08	6.75
1985.	6.47	7.39	7.27	5.04	10.08	5.09	6.68
1986.	6.47	7.43	7.22	4.99	9.96	5.19	6.65
1987.	6.39	7.45	7.10	4.82	10.49	5.19	6.16
1988.	6.36	7.49	7.04	4.71	10.29	5.12	5.83
1989.	6.47	7.65	7.20	4.79	10.60	5.07	6.21
1990.	6.57	7.83	7.33	4.81	10.74	4.96	6.42
1991.	6.76	8.05	7.55	4.91	10.81	5.12	6.44
1992.	6.85	8.22	7.67	4.93	11.01	5.09	7.03
1993.	6.94	8.29	7.73	4.87	11.20	6.07	7.12
1994.	6.91	8.38	7.73	4.73	10.97	5.89	7.19
1995.	6.90	8.40	7.70	4.66	10.97	5.90	6.87
1996.	6.86	8.36	7.64	4.61	10.18	6.13	6.82
1997.	6.85	8.43	7.58	4.54	11.07	5.86	7.07
1998.	6.74	8.26	7.41	4.48	11.52	5.72	N/A
1999.	6.66	8.16	7.26	4.43	11.39	5.47	N/A

Based on sales data in Table 38 and revenue data in Table 56.
N/A Not available.
* *Beginning with 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in Other Revenues.*

TABLE 64

Average Revenues Per Kilowatthour Sold
Investor-Owned Electric Utilities

Cents Per Kilowatthour

Year	Total Ultimate Customers	Residential	Commercial	Industrial	Street and Highway Lighting	Other Revenues*	Railroads and Railways
1979.	3.99	4.63	4.68	3.06	6.60	3.33	3.80
1980.	4.72	5.36	5.47	3.68	7.58	3.95	5.17
1981.	5.45	6.19	6.28	4.29	8.55	4.36	6.20
1982.	6.10	6.81	6.86	4.91	9.54	4.80	6.77
1983.	6.27	7.15	7.04	4.90	10.13	5.22	6.55
1984.	6.52	7.53	7.33	5.07	10.78	5.26	6.97
1985.	6.72	7.79	7.47	5.20	11.22	5.25	7.00
1986.	6.70	7.78	7.40	5.12	11.38	5.43	6.94
1987.	6.56	7.75	7.24	4.88	11.53	5.37	6.58
1988.	6.51	7.78	7.16	4.77	11.36	5.28	6.26
1989.	6.62	7.95	7.33	4.83	11.61	5.16	6.40
1990.	6.77	8.17	7.47	4.92	11.84	5.00	6.58
1991.	7.01	8.46	7.72	5.05	12.23	5.20	6.98
1992.	7.08	8.63	7.84	5.07	12.42	5.04	7.07
1993.	7.19	8.73	7.89	4.99	13.13	6.48	6.93
1994.	7.14	8.83	7.90	4.81	12.71	6.05	7.24
1995.	7.16	8.87	7.88	4.78	12.48	6.05	6.95
1996.	7.13	8.86	7.83	4.73	11.99	5.88	6.85
1997.	7.11	8.94	7.82	4.68	12.51	5.94	7.32
1998r	6.94	8.67	7.57	4.60	12.47	5.88	N/A
1999.	6.83	8.50	7.37	4.53	12.57	5.67	N/A

Based on sales data in Table 39 and revenue data in Table 57.
N/A Not available.
* *Beginning with 1998, data for Other Public Authorities, Railroads and Railways and Interdepartmental are all combined in Other Revenues.*

TABLE 65

Average Annual Revenue Per Customer

Total Electric Utility Industry					Investor-Owned Electric Utilities				
Year	Total Ultimate Customers	Residential	Commercial	Industrial	Year	Total Ultimate Customers	Residential	Commercial	Industrial
1979. . .	$897.17	$391.30	$2,394.04	N/A	1979. . .	$928.41	$387.34	$2,555.09	N/A
1980. . .	1,040.22	461.81	2,848.00	N/A	1980. . .	1,083.28	457.29	3,022.55	N/A
1981. . .	1,188.44	517.39	3,206.52	$67,266.27	1981. . .	1,239.87	514.38	3,499.79	N/A
1982. . .	1,285.29	563.09	3,452.36	66,668.67	1982. . .	1,338.79	562.54	3,867.11	$74,322.38
1983. . .	1,348.80	601.77	3,660.14	73,275.14	1983. . .	1,397.10	599.44	4,011.41	75,219.20
1984. . .	1,452.62	643.75	3,939.57	81,118.33	1984. . .	1,511.99	640.47	4,346.35	82,183.29
1985. . .	1,481.57	658.11	4,080.42	80,821.32	1985. . .	1,555.15	661.10	4,522.86	88,394.19
1986. . .	1,493.81	675.17	4,126.94	81,176.66	1986. . .	1,553.65	671.60	4,548.55	88,389.35
1987. . .	1,500.59	687.95	4,146.61	82,826.13	1987. . .	1,551.79	683.65	4,547.63	88,447.85
1988. . .	1,536.48	711.78	4,255.93	84,088.95	1988. . .	1,584.24	706.82	4,638.54	88,899.76
1989. . .	1,576.46	724.50	4,362.81	85,945.62	1989. . .	1,625.50	720.74	4,777.05	90,211.75
1990. . .	1,614.22	744.03	4,494.39	88,347.48	1990. . .	1,686.85	740.04	4,914.86	89,897.13
1991. . .	1,670.24	782.06	4,645.95	87,321.60	1991. . .	1,738.56	784.80	5,140.47	91,449.11
1992. . .	1,667.46	772.10	4,681.21	86,071.00	1992. . .	1,736.64	772.58	5,176.04	92,350.18
1993. . .	1,726.69	817.92	4,976.87	85,633.79	1993. . .	1,802.86	820.39	5,481.93	93,682.91
1994. . .	1,732.97	827.03	5,075.55	80,515.50	1994. . .	1,815.91	828.17	5,636.78	90,161.86
1995. . .	1,756.29	843.87	5,144.28	81,949.64	1995. . .	1,836.90	849.94	5,689.06	82,227.98
1996. . .	1,769.18	858.84	5,140.03	80,952.23	1996. . .	1,845.11	860.85	5,680.22	90,834.37
1997. . .	1,781.28	848.62	5,208.71	82,951.55	1997. . .	1,843.11	853.62	5,706.03	91,706.11
1998r. .	1,760.41	856.81	5,188.62	86,516.30	1998. . .	1,833.91	858.45	5,608.49	90,888.92
1999p. .	1,720.44	848.16	5,048.15	85,441.02	1999. . .	1,771.10	841.71	5,394.62	89,277.78

Based on revenue data in Tables 56 and 57, and customer data in Tables 47 and 48.
N/A Not Available.
r Revised.
p Preliminary.

TABLE 68
Revenue and Use Per Total Ultimate Customer
By State - 1999

State/Division	Total Electric Utility Industry			Investor-Owned Electric Utilities		
	Avg. Annual Revenue per Customer	Avg. Revenue per kWh Sold	Avg. Annual kWh Use per Customer	Avg. Annual Revenue per Customer	Avg. Revenue per kWh Sold	Avg. Annual kWh Use per Customer
Total United States	**$1,720.44**	**6.66 ¢**	**25,837**	**$1,771.10**	**6.83 ¢**	**25,947**
Maine	1,613.16	9.77	16,508	1,625.95	9.89	16,434
New Hampshire	1,830.46	11.75	15,582	1,895.72	11.49	16,500
Vermont	1,763.73	10.28	17,155	1,904.29	10.26	18,559
Massachusetts	1,550.13	9.16	16,915	1,531.65	9.19	16,664
Rhode Island	1,282.74	9.02	14,225	1,285.89	9.02	14,260
Connecticut	1,974.38	9.96	19,825	1,970.79	10.11	19,490
New England	**1,674.13**	**9.71**	**17,235**	**1,680.86**	**9.77**	**17,206**
New York	1,800.60	10.40	17,313	1,654.51	11.03	15,001
New Jersey	1,956.53	9.99	19,576	1,965.95	10.01	19,633
Pennsylvania	1,442.42	7.67	18,812	1,462.12	7.62	19,195
Middle Atlantic	**1,722.49**	**9.42**	**18,288**	**1,666.43**	**9.52**	**17,504**
Ohio	2,023.48	6.40	31,607	2,115.59	6.40	33,063
Indiana	1,816.45	5.29	34,341	1,980.61	5.18	38,210
Illinois	1,794.89	6.98	25,727	1,826.54	6.95	26,271
Michigan	1,629.25	7.14	22,822	1,678.48	7.17	23,417
Wisconsin	1,366.95	5.53	24,714	1,397.29	5.54	25,211
East North Central	**1,765.14**	**6.38**	**27,655**	**1,833.80**	**6.39**	**28,698**
Minnesota	1,469.28	5.83	25,222	1,647.20	5.68	29,007
Iowa	1,591.71	5.93	26,847	1,655.90	5.89	28,134
Missouri	1,528.73	6.07	25,202	1,693.30	6.19	27,338
North Dakota	1,468.81	5.49	26,707	1,219.15	5.70	21,383
South Dakota	1,324.79	6.35	20,866	1,429.45	6.57	21,758
Nebraska	1,368.11	5.31	25,753	–	–	–
Kansas	1,580.61	6.22	25,428	1,637.00	6.02	27,180
West North Central	**1,505.47**	**5.92**	**25,419**	**1,637.28**	**5.97**	**27,437**
Delaware	2,015.95	7.12	28,323	2,163.98	6.94	31,191
Maryland	1,911.75	7.04	27,167	1,942.11	7.00	27,726
District of Columbia	3,530.89	7.45	47,370	3,530.8[illegible]	7.45	47,370
Virginia	1,781.02	5.86	30,377	1,834.55	5.75	31,888
West Virginia	1,465.12	5.09	28,757	1,471.82	5.08	28,974
North Carolina	1,850.10	6.44	28,710	1,978.80	6.02	32,884
South Carolina	2,030.47	5.57	36,432	2,256.69	5.47	41,261
Georgia	1,882.24	6.24	30,185	2,203.61	5.85	37,679
Florida	1,610.20	6.85	23,522	1,625.47	6.84	23,775
South Atlantic	**1,791.42**	**6.37**	**28,118**	**1,872.69**	**6.22**	**30,105**
Kentucky	1,656.58	4.17	39,721	1,593.10	4.03	39,556
Tennessee	1,907.57	5.63	33,910	1,794.83	4.40	40,775
Alabama	2,002.72	5.54	36,135	2,156.52	5.60	38,478
Mississippi	1,846.68	5.65	32,675	2,071.57	5.47	37,877
East South Central	**1,863.04**	**5.22**	**35,698**	**1,928.94**	**4.97**	**38,791**
Arkansas	1,688.62	5.68	29,709	1,813.94	5.85	30,993
Louisiana	2,228.46	5.81	38,331	2,449.74	5.67	43,233
Oklahoma	1,451.99	5.37	27,025	1,575.87	5.08	31,022
Texas	2,019.62	6.04	33,416	2,265.38	5.95	38,095
West South Central	**1,949.02**	**5.91**	**32,993**	**2,177.16**	**5.80**	**37,508**
Montana	1,263.44	5.01	25,242	1,156.87	6.12	18,914
Idaho	1,409.93	3.98	35,404	1,446.91	3.88	37,323
Wyoming	1,866.89	4.30	43,457	1,984.27	3.99	49,750
Colorado	1,179.13	5.95	19,813	1,147.47	5.89	19,494
New Mexico	1,432.46	6.58	21,767	1,444.38	6.61	21,867
Arizona	1,965.50	7.23	27,177	2,070.35	7.94	26,091
Utah	1,275.76	4.86	26,240	1,310.43	4.63	28,284
Nevada	1,786.45	5.93	30,148	1,758.61	6.21	28,338
Mountain	**1,533.14**	**5.89**	**26,039**	**1,544.23**	**5.92**	**26,076**
Washington	1,427.34	4.10	34,779	1,388.21	5.60	24,798
Oregon	1,398.62	4.87	28,742	1,411.15	5.11	27,591
California	1,534.31	9.34	16,433	1,493.80	9.77	15,290
Pacific	**1,504.65**	**7.35**	**20,481**	**1,475.40**	**8.47**	**17,421**
Alaska	1,917.55	9.78	19,615	2,114.60	11.79	17,941
Hawaii	2,664.08	11.97	22,252	2,664.08	11.97	22,252
Alaska & Hawaii	**2,372.74**	**11.18**	**21,223**	**2,633.84**	**11.96**	**22,015**

TABLE 67
Revenue and Use Per Residential Customer
By State - 1999

	Total Electric Utility Industry			Investor-Owned Electric Utilities		
State/Division	Avg. Annual Revenue per Customer	Avg. Revenue per kWh Sold	Avg. Annual kWh Use per Customer	Avg. Annual Revenue per Customer	Avg. Revenue per kWh Sold	Avg. Annual kWh Use per Customer
Total United States	**$848.16**	**8.16 ¢**	**10,388**	**$841.71**	**8.50 ¢**	**9,897**
Maine	773.55	13.07	5,918	781.18	13.22	5,911
New Hampshire	929.71	13.84	6,716	920.67	13.51	6,814
Vermont	867.51	12.17	7,130	910.53	12.50	7,285
Massachusetts	703.15	10.09	6,969	701.18	10.25	6,843
Rhode Island	643.28	10.13	6,352	643.45	10.13	6,350
Connecticut	977.98	11.46	8,533	985.31	11.56	8,525
New England	**801.10**	**11.18**	**7,166**	**805.85**	**11.29**	**7,135**
New York	858.13	13.32	6,444	816.78	13.76	5,935
New Jersey	888.74	11.40	7,799	890.77	11.44	7,786
Pennsylvania	830.61	9.19	9,040	830.63	9.16	9,072
Middle Atlantic	**856.09**	**11.31**	**7,569**	**839.12**	**11.30**	**7,425**
Ohio	873.80	8.68	10,071	888.50	8.91	9,971
Indiana	800.39	6.96	11,497	797.52	7.05	11,314
Illinois	757.24	8.83	8,572	736.99	8.86	8,321
Michigan	659.51	8.73	7,556	673.09	8.80	7,646
Wisconsin	624.50	7.31	8,542	614.07	7.41	8,290
East North Central	**754.38**	**8.26**	**9,129**	**753.75**	**8.42**	**8,947**
Minnesota	661.39	7.41	8,921	604.96	7.86	7,696
Iowa	806.69	8.35	9,659	773.53	8.75	8,845
Missouri	821.73	7.12	11,544	835.09	7.34	11,374
North Dakota	749.69	6.50	11,542	584.25	6.30	9,272
South Dakota	769.15	7.42	10,365	682.25	7.90	8,639
Nebraska	719.95	6.52	11,040	—	—	—
Kansas	775.69	7.64	10,147	770.87	7.34	10,509
West North Central	**759.46**	**7.36**	**10,320**	**740.35**	**7.67**	**9,659**
Delaware	978.03	9.17	10,669	983.69	9.30	10,574
Maryland	1,003.49	8.39	11,955	993.75	8.41	11,810
District of Columbia	677.92	8.00	8,475	677.92	8.00	8,475
Virginia	985.94	7.48	13,176	977.28	7.41	13,187
West Virginia	729.13	6.27	11,622	728.89	6.25	11,653
North Carolina	1,003.39	7.99	12,563	975.73	7.62	12,809
South Carolina	1,037.91	7.55	13,739	1,032.57	7.49	13,788
Georgia	958.41	7.56	12,672	879.81	7.25	12,142
Florida	1,036.04	7.73	13,405	1,045.04	7.76	13,468
South Atlantic	**994.00**	**7.72**	**12,869**	**978.45**	**7.63**	**12,816**
Kentucky	724.79	5.58	12,996	661.06	5.13	12,898
Tennessee	950.80	6.34	14,989	836.58	4.95	16,912
Alabama	1,000.35	7.03	14,230	1,030.25	7.30	14,118
Mississippi	956.36	6.75	14,164	959.76	6.73	14,269
East South Central	**909.97**	**6.42**	**14,171**	**878.59**	**6.39**	**13,741**
Arkansas	899.30	7.43	12,111	924.17	7.78	11,885
Louisiana	1,050.53	7.12	14,753	1,044.81	7.14	14,630
Oklahoma	807.85	6.60	12,238	789.95	6.33	12,473
Texas	1,047.10	7.55	13,865	1,100.64	7.71	14,278
West South Central	**1,004.50**	**7.37**	**13,630**	**1,041.24**	**7.47**	**13,932**
Montana	631.93	6.78	9,316	555.19	7.06	7,862
Idaho	693.23	5.26	13,177	679.68	5.23	12,992
Wyoming	586.55	6.34	9,255	512.01	6.18	8,291
Colorado	565.65	7.38	7,666	536.28	7.49	7,159
New Mexico	562.56	8.62	6,523	565.80	8.36	6,767
Arizona	1,013.09	8.53	11,870	1,030.29	9.19	11,210
Utah	529.47	6.27	8,440	520.79	6.18	8,428
Nevada	786.19	7.13	11,030	788.15	7.21	10,925
Mountain	**721.63**	**7.44**	**9,700**	**701.00**	**7.49**	**9,358**
Washington	700.07	5.10	13,729	736.93	5.90	12,490
Oregon	736.78	5.75	12,817	727.48	6.02	12,086
California	704.41	10.71	6,577	724.33	10.98	6,596
Pacific	**706.74**	**8.53**	**8,288**	**725.86**	**9.43**	**7,698**
Alaska	916.09	11.16	8,210	1,026.88	12.00	8,555
Hawaii	1,057.06	14.30	7,394	1,057.06	14.30	7,394
Alaska & Hawaii	**1,002.85**	**13.01**	**7,708**	**1,055.50**	**14.16**	**7,454**

TABLE 68
Revenue and Use Per Commercial Customer
By State - 1999

State/Division	Total Electric Utility Industry: Avg. Annual Revenue per Customer	Total Electric Utility Industry: Avg. Revenue per kWh Sold	Total Electric Utility Industry: Avg. Annual kWh Use per Customer	Investor-Owned Electric Utilities: Avg. Annual Revenue per Customer	Investor-Owned Electric Utilities: Avg. Revenue per kWh Sold	Investor-Owned Electric Utilities: Avg. Annual kWh Use per Customer
Total United States	**$5,048.15**	**7.28 ¢**	**69,508**	**$5,394.62**	**7.37 ¢**	**73,214**
Maine	4,812.01	10.51	45,777	4,987.33	10.55	47,274
New Hampshire	4,806.66	11.39	42,191	5,013.43	11.18	44,934
Vermont	5,040.36	10.67	47,217	5,387.75	10.74	50,155
Massachusetts	5,947.99	8.90	66,815	6,145.94	8.82	69,657
Rhode Island	5,048.49	8.49	59,495	5,074.36	8.48	59,809
Connecticut	8,768.26	9.69	90,462	9,088.24	9.74	93,279
New England	**6,109.26**	**9.49**	**64,352**	**6,338.46**	**9.46**	**67,027**
New York	6,452.43	11.19	57,674	6,100.59	11.38	53,590
New Jersey	7,285.41	9.74	74,779	7,329.10	9.75	75,183
Pennsylvania	3,838.77	7.90	48,601	3,878.30	7.88	49,202
Middle Atlantic	**5,912.23**	**9.98**	**59,224**	**5,758.05**	**9.95**	**57,884**
Ohio	5,850.62	7.67	76,317	6,156.16	7.71	79,829
Indiana	4,290.71	6.05	70,924	4,529.58	6.09	74,343
Illinois	6,431.26	7.39	87,045	6,586.65	7.45	88,456
Michigan	6,111.72	7.86	77,785	6,365.44	7.95	80,109
Wisconsin	3,821.32	5.88	64,998	3,991.32	5.93	67,326
East North Central	**5,552.84**	**7.22**	**76,926**	**5,812.96**	**7.29**	**79,695**
Minnesota	3,067.20	6.31	48,612	2,654.05	6.51	40,744
Iowa	3,183.55	6.45	49,345	3,181.75	6.61	48,127
Missouri	4,658.21	5.97	78,014	5,357.80	6.05	88,494
North Dakota	3,048.41	6.19	49,285	2,818.63	6.08	46,346
South Dakota	3,059.86	6.70	45,692	3,144.82	6.97	45,088
Nebraska	3,074.82	5.44	56,541		—	—
Kansas	4,082.61	6.25	65,320	5,040.10	5.97	84,464
West North Central	**3,699.26**	**6.12**	**60,490**	**4,029.44**	**6.22**	**64,825**
Delaware	6,517.73	7.39	88,150	7,444.94	7.16	103,990
Maryland	7,985.35	6.82	117,149	8,284.30	6.80	121,741
District of Columbia	23,353.87	7.47	312,487	23,353.87	7.47	312,487
Virginia	5,003.72	5.55	90,109	5,254.98	5.46	96,314
West Virginia	3,084.72	5.53	55,732	3,095.10	5.52	56,032
North Carolina	4,437.28	6.33	70,053	4,353.26	5.98	72,774
South Carolina	3,918.36	6.30	62,181	4,294.43	6.14	69,969
Georgia	5,783.39	6.67	86,770	6,694.58	6.46	103,630
Florida	4,979.99	6.22	80,023	5,121.58	6.16	83,207
South Atlantic	**5,247.39**	**6.34**	**82,742**	**5,560.21**	**6.21**	**89,514**
Kentucky	3,067.99	5.27	58,243	3,167.64	4.91	64,499
Tennessee	4,282.48	6.29	68,101	3,845.00	5.01	76,690
Alabama	3,904.63	6.54	59,661	4,342.72	6.55	66,258
Mississippi	3,836.87	6.19	61,965	4,799.48	5.78	83,017
East South Central	**3,847.16**	**6.14**	**62,638**	**4,028.82**	**5.82**	**69,166**
Arkansas	3,492.48	5.82	59,985	3,795.61	5.64	67,351
Louisiana	5,432.98	6.59	82,436	5,738.83	6.57	87,393
Oklahoma	3,399.59	5.58	60,919	4,032.14	5.30	76,087
Texas	4,976.86	6.52	76,284	5,789.33	6.49	89,157
West South Central	**4,707.02**	**6.38**	**73,723**	**5,407.11**	**6.32**	**85,510**
Montana	2,783.15	6.35	43,804	3,026.45	6.49	46,609
Idaho	2,985.96	4.20	71,034	2,997.18	4.12	72,757
Wyoming	2,917.23	5.28	55,257	2,797.60	5.13	54,520
Colorado	4,042.18	5.61	72,071	4,709.02	5.42	86,931
New Mexico	4,334.40	7.53	57,588	4,980.92	7.49	66,468
Arizona	7,408.80	7.51	98,705	7,490.79	8.19	91,478
Utah	4,763.61	5.29	90,082	5,024.42	5.08	98,837
Nevada	3,725.06	6.66	55,968	3,726.20	6.78	54,967
Mountain	**4,572.20**	**6.27**	**72,886**	**4,709.38**	**6.25**	**75,303**
Washington	4,099.91	4.86	84,287	4,833.82	5.96	81,111
Oregon	3,627.36	4.94	73,402	3,792.17	5.06	75,004
California	5,281.69	10.05	52,546	5,310.63	10.14	52,364
Pacific	**4,946.21**	**8.37**	**59,117**	**5,101.45**	**8.87**	**57,481**
Alaska	6,007.28	9.20	65,286	5,458.39	15.39	35,475
Hawaii	6,941.59	12.74	54,494	6,941.59	12.74	54,494
Alaska & Hawaii	**6,560.28**	**11.14**	**58,898**	**6,843.67**	**12.85**	**53,241**

TABLE 69
Revenue and Use Per Industrial Customer
By State - 1999

	Total Electric Utility Industry			Investor-Owned Electric Utilities		
State/Division	Avg. Annual Revenue per Customer	Avg. Revenue per kWh Sold	Avg. Annual kWh Use per Customer	Avg. Annual Revenue per Customer	Avg. Revenue per kWh Sold	Avg. Annual kWh Use per Customer
Total United States	**$85,441.02**	**4.43 ¢**	**1,930,072**	**$89,277.78**	**4.53 ¢**	**1,970,148**
Maine	112,480.57	6.42	1,751,339	112,648.25	6.47	1,740,085
New Hampshire	70,006.06	9.21	760,296	68,270.65	9.22	740,073
Vermont	265,165.91	7.35	3,607,838	1,357,000.00	7.07	19,206,444
Massachusetts	52,576.96	7.75	678,337	66,793.06	7.59	880,102
Rhode Island	33,631.71	7.39	455,298	33,537.75	7.38	454,421
Connecticut	73,219.57	7.42	986,397	68,383.33	7.55	908,196
New England	**66,031.60**	**7.53**	**876,793**	**73,197.91**	**7.49**	**977,416**
New York	140,879.69	4.77	2,952,448	151,270.14	5.62	2,691,436
New Jersey	76,958.04	7.69	1,000,846	76,303.36	7.70	990,698
Pennsylvania	63,105.73	5.22	1,208,260	63,535.58	5.20	1,222,605
Middle Atlantic	**81,673.76**	**5.53**	**1,475,960**	**81,819.58**	**5.88**	**1,395,351**
Ohio	107,158.59	4.33	2,477,257	108,556.94	4.28	2,487,678
Indiana	100,474.47	3.89	2,579,616	109,337.90	3.83	2,857,148
Illinois	387,338.78	5.02	7,720,272	611,721.62	5.01	12,211,161
Michigan	137,606.59	5.05	2,723,527	147,725.60	5.02	2,943,931
Wisconsin	188,198.25	3.89	4,781,939	235,683.57	3.89	6,059,554
East North Central	**137,797.58**	**4.43**	**3,108,798**	**149,508.21**	**4.41**	**3,391,895**
Minnesota	114,457.49	4.56	2,508,753	129,490.39	4.56	2,839,288
Iowa	161,741.63	3.89	4,154,885	206,976.38	3.84	5,388,448
Missouri	73,679.46	4.38	1,681,106	69,848.71	4.59	1,522,279
North Dakota	65,412.05	4.04	1,620,508	70,271.41	4.39	1,600,803
South Dakota	47,076.43	4.55	1,034,488	120,475.14	4.68	2,571,994
Nebraska	29,205.91	3.57	817,412	–	–	–
Kansas	33,165.74	4.47	741,204	48,083.06	4.42	1,088,152
West North Central	**69,777.47**	**4.28**	**1,630,211**	**98,334.45**	**4.38**	**2,246,337**
Delaware	305,669.69	4.73	6,459,804	424,383.12	4.57	9,295,084
Maryland	55,465.48	4.26	1,301,731	54,335.92	4.20	1,293,237
District of Columbia	11,439,000.00	4.59	249,201,000	11,439,000.00	4.59	249,201,000
Virginia	147,322.48	3.84	3,835,944	153,741.84	3.75	4,099,331
West Virginia	37,786.63	3.80	993,333	37,775.40	3.80	993,347
North Carolina	122,182.05	4.57	2,675,192	124,106.90	4.48	2,769,890
South Carolina	244,093.67	3.72	6,554,472	214,697.39	3.82	5,619,976
Georgia	133,170.75	4.15	3,208,812	126,966.61	4.19	3,027,210
Florida	37,930.97	4.77	795,579	29,603.44	4.65	636,505
South Atlantic	**90,117.84**	**4.18**	**2,155,114**	**83,110.55**	**4.16**	**1,997,595**
Kentucky	173,746.62	2.99	5,819,297	124,387.72	2.87	4,335,683
Tennessee	750,114.33	4.19	17,914,233	126,500.00	3.49	3,623,515
Alabama	206,920.82	3.82	5,414,387	169,227.22	3.84	4,404,434
Mississippi	140,282.42	4.02	3,493,590	80,388.54	3.96	2,031,038
East South Central	**228,764.64**	**3.67**	**6,239,591**	**128,692.16**	**3.47**	**3,708,281**
Arkansas	26,692.91	4.12	647,226	18,681.39	4.42	422,379
Louisiana	86,757.90	4.25	2,041,892	88,485.70	4.21	2,103,212
Oklahoma	31,188.99	3.60	865,466	27,672.42	3.51	788,443
Texas	60,580.90	3.97	1,524,372	72,833.51	3.87	1,879,915
West South Central	**53,033.86**	**4.01**	**1,321,601**	**55,909.30**	**3.98**	**1,412,251**
Montana	34,149.74	2.84	1,200,753	16,643.22	3.99	416,814
Idaho	34,662.68	2.74	1,263,257	35,685.38	2.70	1,319,341
Wyoming	61,939.29	3.34	1,856,658	63,577.09	3.23	1,969,867
Colorado	149,500.90	4.38	3,416,192	559,627.30	4.25	13,170,785
New Mexico	40,855.47	4.25	960,617	56,872.61	4.23	1,346,071
Arizona	122,351.64	5.04	2,425,276	92,654.99	5.58	1,659,867
Utah	29,103.31	3.38	866,810	27,358.61	3.27	837,344
Nevada	381,150.96	4.77	7,997,591	402,974.34	5.15	7,828,758
Mountain	**68,995.98**	**4.01**	**1,721,440**	**65,819.51**	**4.11**	**1,602,125**
Washington	48,279.07	2.70	1,786,020	22,292.40	4.13	539,386
Oregon	40,564.14	3.55	1,144,174	32,284.75	3.84	840,082
California	87,368.60	7.16	1,219,924	315,275.87	6.95	4,534,832
Pacific	**69,112.62**	**5.08**	**1,360,092**	**100,219.45**	**6.03**	**1,662,593**
Alaska	130,517.97	7.32	1,783,791	42,267.33	7.46	566,881
Hawaii	550,202.72	9.70	5,669,728	550,202.72	9.70	5,669,728
Alaska & Hawaii	**375,149.03**	**9.27**	**4,048,874**	**482,877.95**	**9.67**	**4,993,366**

SECTION IX
FINANCIAL

TABLE 70
Construction Expenditures
Investor-Owned Electric Utilities
By Type of Plant
Millions of Dollars

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Production											
Steam	$7,572	$7,498	$7,221	$7,828	$5,860	$5,569	$4,725	$4,333	$4,478	$3,946	$4,044
Nuclear	9,855	11,045	12,785	16,461	18,208	17,478	15,553	13,426	9,239	5,272	4,768
Other	854	695	906	1,050	868	893	1,095	724	678	740	1,091
Total	18,281	19,238	20,912	25,339	24,935	23,939	21,372	18,483	14,395	9,959	9,903
Transmission	2,090	2,353	2,270	2,203	2,371	2,250	1,863	1,761	2,066	1,942	2,512
Distribution	4,334	4,483	4,606	4,827	5,021	5,899	6,590	7,248	7,457	8,224	8,685
General/Miscellaneous*	776	937	1,336	1,233	1,489	1,355	1,266	1,808	1,585	1,725	1,997
Subtotal	25,481	27,011	29,124	33,602	33,816	33,443	31,091	29,299	25,503	21,851	23,097
Nuclear Fuel	1,338	1,324	1,566	1,748	1,749	1,842	2,202	1,724	1,532	1,780	1,663
GRAND TOTAL	$26,819	$28,335	$30,690	$35,350	$35,565	$35,285	$33,294	$31,023	$27,035	$23,630	$24,760
AFUDC included in TOTAL	$3,593	$4,365	$5,358	$6,612	$7,816	$7,923	$6,941	$5,659	$4,579	$2,711	$2,241

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999p
Production										
Steam	$3,951	$4,108	$4,082	$5,053	$5,146	$3,580	$2,707	$2,050	$2,327	
Nuclear	3,837	3,209	3,090	2,409	1,845	1,913	1,598	1,650	1,595	
Other	1,045	1,008	1,183	1,937	1,879	1,820	1,585	1,812	2,141	
Total	8,833	8,325	8,356	9,399	8,870	7,313	5,890	5,513	6,063	Data
Transmission	2,441	2,294	2,610	2,647	2,572	2,476	2,113	2,645	2,546	not
Distribution	9,100	8,780	8,653	9,017	9,195	8,316	8,368	8,709	10,262	Available
General/Miscellaneous*	2,163	2,416	2,799	2,519	2,445	2,091	2,385	2,052	2,351	at time
Subtotal	22,537	21,815	22,419	23,582	23,080	20,196	18,757	18,918	21,222	of Printing
Nuclear Fuel	1,650	1,544	1,827	1,625	1,648	1,652	1,504	1,317	1,427	
GRAND TOTAL	$24,187	$23,360	$24,246	$25,207	$24,728	$21,848	$20,261	$20,235	$22,649	
AFUDC included in TOTAL	$1,708	$1,132	$1,347	$944	$645	$492	$465	$462	$423	

Note: Total may not equal sum of components due to independent rounding.

This table has been restructured based on data submitted to the Institute. Data, compiled on a 50 state basis, now includes nuclear fuel and reflects the amount of AFUDC in the total.

Construction expenditures are, in general, the gross amounts spent for construction of all kinds, including the acquisition of real estate and all necessary equipment. The figures include money spent for replacements, additions, and betterments (but not for maintenance of existing plant) as well as for new construction.

**Includes intangible plant.*

p Preliminary. Data not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.

TABLE 71

Combined Balance Sheets - December 31st
Investor-Owned Electric Utilities

Intercompany Transactions Eliminated
Millions of Dollars

	1994	1995	1996	1997	1998r	1999p
ASSETS						
Utility Plant:						
Electric	$546,540	$561,377	$585,716	$590,027		
Other	34,226	37,305	41,490	54,969		
Total Utility Plant	580,766	598,682	627,206	644,996		
Accumulated Provision for Depreciation and Amortization	201,669	215,803	237,022	252,381		
Net Utility Plant	379,097	382,879	390,184	392,615		
Construction Work in Progress	19,323	15,336	12,085	13,540		
Nuclear Fuel	19,407	18,632	15,438	14,668		
Accumulated Provision for Amortization of Nuclear Fuel Assemblies	13,749	13,405	8,917	8,342		
Net Nuclear Fuel	5,658	5,227	6,521	6,325		
Net Total Utility Plant	404,078	403,442	408,791	412,480		
Other Property and Investment*	27,961	31,384	52,644	74,226		
Total Current and Accrued Assets	44,004	47,229	49,830	61,135		
Total Deferred Debits	83,850	87,678	87,638	90,536		
Total Assets	$559,893	$569,733	$598,902	$638,377	See next Page	
CAPITALIZATION AND LIABILITIES						
Capitalization:						
Common Capital Stock	$64,687	$67,189	$89,427	$80,944		
Other Paid-In Capital Excluding Retained Earnings**	46,026	43,650	35,865	40,333		
Retained Earnings	56,352	58,317	57,379	66,161		
Total Common Capital Stock Equity	167,065	169,156	182,671	187,439		
Preferred Stock	23,123	21,420	18,590	19,272		
Long-Term Debt:						
Mortgage Bonds	122,135	120,198	120,787	116,154		
Other Long-Term Debt	52,432	54,816	60,467	81,244		
Total Long-Term Debt	174,567	175,014	181,255	197,398		
Total Capitalization	364,755	365,590	382,516	404,108		
Total Other Non-Current Liabilities	9,479	10,955	6,427	6,127		
Total Current and Accrued Liabilities	55,385	57,869	64,668	78,496		
Contribution in Aid of Construction	179	192	274	198		
Deferred Income Taxes	90,728	94,716	99,007	94,847		
Deferred Investment Tax Credits	13,335	12,029	10,870	11,893		
Other Deferred Credits	26,033	28,381	35,140	42,708		
Total Capitalization and Liabilities	$559,893	$569,733	$598,902	$638,377		

Note: Total may not equal sum of components due to independent rounding. Data for prior years do not reflect restatements. Data based on reports as submitted by electric utilities, some of which report on a consolidated basis.
Data comprising "Net Total Utility Plant" has been reformatted to reflect changes made to Schedule VI of the Uniform Statistical Report.
Previous years' data have been revised for comparability.
**Beginning 1990 "Other Property and Investment" includes decommissioning funds (1993 - $5,795 million; 1994 - $8,531 million; 1995 - $8,125 million; 1996 - $11,978 million; 1997 - $15,268 million; 1998 $18,354 million).*
***Includes Premium on Common and Preferred Stock.*
r Revised. p Preliminary. Complete data for 1998r and 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.

TABLE 71B

Combined Balance Sheets - December 31st
Investor-Owned Electric Utilities

Intercompany Transactions Eliminated
Millions of Dollars

	1998r	1999p
ASSETS		
Gross Property and Equipment*	$650,063	$656,334
Less Accumulated Depreciation	(260,264)	(265,367)
Net Property in Service	389,799	390,967
Construction Work in Progress	11,742	13,834
Other Property	3,366	4,014
Net Nuclear Fuel	4,616	4,338
Net Property and Equipment	409,523	413,152
Total Investments	88,596	106,564
Total Current Assets	82,625	96,266
Total Deferred Debits	105,316	126,074
Total Assets	$686,061	$742,056
CAPITALIZATION AND LIABILITIES		
Common Stock	$134,359	$118,809
Retained Earnings	51,538	65,428
Total Common Equity	185,897	184,237
Total Preferred/Preference Dollars	24,175	25,765
Total Long-Term Debt	209,396	229,686
Total Capitalization	419,468	439,688
Current Liabilities		
Total Current Liabilities	109,265	138,560
Total Other Liabilities and Deferred Credits	157,328	163,808
Total Capitalization and Liabilities	$686,061	$742,056

Note: Total may not equal sum of components due to independent rounding.
** Includes nonelectric utility plant.*
r Revised. p Preliminary. Complete data for 1998r and 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.
Source: EEI Finance Department.

TABLE 72A

Combined Income Statements - December 31st
Investor-Owned Electric Utilities

Intercompany Transactions Eliminated
Millions of Dollars

	1993	1994	1995
		Electric Department Only	
Operating Revenues.	$162,319	$167,617	$172,681
Operating Expenses:			
Operation.	77,906	80,693	81,148
Maintenance.	12,288	11,981	11,777
Depreciation and Depletion.	16,707	17,978	18,803
Amortization Charged to Operation.	954	1,171	1,028
Property Losses Charged to Operation.	229	244	159
Deferred Expenses*.	381	539	853
Taxes Other Than Income Taxes.	12,980	13,316	13,548
Federal Income Taxes.	7,144	8,351	9,824
State Income Taxes.	1,153	1,337	1,508
Deferred Income Taxes:			
Federal.	2,744	1,715	1,512
State.	242	63	51
Investment Tax Credit Adjustment.	(452)	(495)	(510)
Total Operating Expenses.	132,275	136,873	139,709
Operating Income.	$30,044	$30,744	$32,981
		All Departments	
Operating Revenues.	$182,636	$188,225	$192,210
Operating Expenses:			
Operation.	92,712	95,492	94,868
Maintenance.	12,876	12,587	12,373
Depreciation and Depletion.	18,019	19,359	20,145
Amortization Charged to Operation.	995	1,233	1,074
Property Losses Charged to Operation.	330	259	178
Deferred Expenses*.	384	559	917
Taxes Other Than Income Taxes.	14,113	14,491	14,713
Federal Income Taxes.	7,260	8,669	10,141
State Income Taxes.	1,195	1,390	1,590
Deferred Income Taxes:			
Federal.	3,120	1,980	1,830
State.	269	69	24
Investment Tax Credit Adjustment.	(477)	(521)	(527)
Total Operating Expenses.	150,797	155,567	157,327
Operating Income.	$31,839	$32,658	$34,883
Other Income (Non-Operating) Net.	(317)	1,124	1,243
Allowance for Other Funds Used During Construction.	596	391	310
Income Before Interest Charges (Gross Income).	32,118	34,173	36,435
Interest Charges:			
Interest on Long-Term Debt.	13,783	13,302	13,006
Interest on Short-Term Debt.	308	400	453
Amortization of Debt Discount Expense and Premium.	462	473	577
Other Interest Expense.	842	820	1,021
Allowance for Borrowed Funds Used During Construction	(556)	(464)	(453)
Net Interest Charges.	14,839	14,531	14,804
Income Before Extraordinary Items.	17,280	19,641	21,831
Extraordinary Items**.	137	22	(836)
Net Income.	17,417	19,663	20,995
Preferred Dividend Charges.	1,714	1,624	1,515
Available for Common Stock.	15,703	18,039	19,481
Common Dividend.	14,744	15,116	15,388
Net Income After Dividends.	$959	$2,922	$4,093

Note: Total may not equal sum of components due to independent rounding. See page 69 for footnote.
Deferred Income Taxes now shown as "Total Federal" (previously shown as "Property Related") and "Total State" (previously shown as "Non-Property Related").
** "Deferred Expenses" include Rate Deferrals - Net (1992 - $123; 1993 - $289; 1994 - $394; 1995 - $408).*
*** "Extraordinary Items" include Cumulative Effects of a change in accounting principle.*
( ) Denotes credit or negative value.

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TABLE 72B

Combined Income Statements - December 31st
Investor-Owned Electric Utilities

Intercompany Transactions Eliminated
Millions of Dollars

	1996	1997r	1998p	1999p
Operating Revenues				
Electric	$178,345	$183,164	$190,474	
Gas	18,598	22,008	19,590	
Other	10,765	29,031	38,308	
Total Operating Revenues	$207,708	$234,203	$248,372	
Operating Expenses				
Operation & Maintenance	117,214	142,650	157,990	
Depreciation & Amortization	23,423	26,096	27,220	
Taxes	27,481	26,265	24,308	
Other	4,500	5,420	5,186	
Total Operating Expenses	$172,618	$200,431	$214,704	
Operating Income	$35,090	$33,772	$33,668	See next Page
Other Income & Deductions				for Revised 1998
AFUDC (Equity)	384	240	185	and
Other	1,002	2,048	1,846	Preliminary 1999
Total Income Before Interest Charges	$36,476	$36,060	$35,699	Data
Interest Charges				
Interest on Long-Term Debt	13,379	14,077	14,548	
Other Interest Expense	2,528	3,745	3,356	
AFUDC	(308)	(283)	(262)	
Net Interest Charges	15,599	17,539	17,642	
Income Before Extraordinary Items	20,877	18,521	18,057	
Extraordinary Items*	310	(3,034)	(1,377)	
NET INCOME	$21,187	$15,487	$16,680	
RETAINED EARNINGS				
Balance, January 1	59,884	64,655	62,304	
Net Income	21,187	15,487	16,680	
Pfd and Pfc Dividends Declared	1,122	726	456	
Common Stock Dividends Declared	14,835	14,305	14,283	
Adjustments	(95)	(1,240)	6	
Balance, December 31	$65,019	$63,871	$65,251	

Note: Total may not equal sum of components due to independent rounding.
Due to reduced reporting, EEI is unable to provide the level of detail formerly shown in Table 72.
p Preliminary. Complete data for 1998r and 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.
() Denotes credit or negative value.
** "Extraordinary Items" include Cumulative Effects of a change in accounting principle.*
Source: Uniform Statistical Report; FERC Form 1; Annual Reports.

TABLE 72C
Combined Income Statements - December 31st
Investor-Owned Electric Utilities
Intercompany Transactions Eliminated
Millions of Dollars

	1998r	1999p
Total Revenues	$295,229	$328,902
Operating Expenses		
Energy Expenses	93,891	106,596
Operation & Maintenance	73,983	84,820
Depreciation & Amortization	28,848	30,337
Other Operating Expenses	39,422	46,800
Taxes (not Income) - Total	13,611	13,198
Income Taxes: Federal and Other	11,258	11,804
Total Operating Expenses	$261,013	$293,556
Operating Income	$34,216	$35,347
Total Other Income	1,719	5,700
Income before Interest Charges	$35,935	$41,047
Net Interest Expense	(17,267)	(18,549)
Net Income before Preferred Distributions	$18,668	$22,498
Total Preferred Distributions	(1,574)	(1,778)
NET INCOME ON COMMON	$17,094	$20,720
Extraordinary Items- Total	(1,795)	(1,508)
Income after Extraordinary Items	$15,299	$19,212
Basic Earnings per Share	$1.76	$2.19
Basic Earning per Share after Extraordinary Items 1/	$1.58	$2.03
Diluted Earnings per Share	$1.76	$2.19
Diluted Earning per Share after Extraordinary Items 1/	$1.57	$2.03
Diluted Average Shares (Millions)	9,736	9,475
Annualized Common Dividend	14,067	14,188
Common Dividends per Share	$1.45	$1.50

Note: Revenues are adjusted for intra-industry sales for resale of electricity. Total may not equal sum of components due to independent rounding.
Due to reduced reporting, EEI is unable to provide the level of detail formerly shown in Table 72.
p Preliminary. Complete data for 1998r and 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.
r Revised.
( ) Denotes credit or negative value.
"Extraordinary Items" include Cumulative Effects of a change in accounting principle.
Source: EEI Finance Department.

TABLE 73
Detail of Electric Operation & Maintenance Expenses
Investor-Owned Electric Utilities+
Millions of Dollars

	1994	1995	1996	1997	1998	1999p
Production	$64,660	$65,761	$69,001	$75,671	$88,253	
Transmission and Distribution	7,838	7,905	8,271	8,636	9,556	Data
Customer Accounts	3,472	3,559	3,841	3,761	4,000	Not Available
Customer Service and Information	2,013	1,994	1,922	1,924	1,971	at time
Sales	225	334	427	444	504	of Printing
Administrative and General	14,428	13,382	13,754	13,407	13,251	
Total Operation & Maintenance Expenses	$92,637	$92,934	$97,218	$103,842	$117,535	
Cost of Fuel*	$29,842	$28,548	$30,451	$30,713	$30,548	

Note: Total may not equal sum of components due to independent rounding.
+ Operating companies only, as of 1998.
**Included in "Total Operation & Maintenance Expenses."*
p Preliminary. Data for 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.

TABLE 74

Detail of Taxes - Electric Department Only
Investor-Owned Electric Utilities+

Millions of Dollars

	1994		1995		1996	
	Amount	% of Oper. Revenue	Amount	% of Oper. Revenue	Amount	% of Oper. Revenue
Federal Taxes						
Income	$8,351	5.0 %	$9,823	5.7 %	$9,724	5.6 %
Deferred Taxes on Income*	1,715	1.0	1,512	0.9	1,496	0.8
Other Deferred Income Taxes**	(495)	N/M	(510)	N/M	(540)	N/M
Miscellaneous Taxes	1,309	0.8	1,241	0.7	1,221	0.7
Total Federal Taxes Charged to Income	10,880	6.5	12,068	7.0	11,901	6.7
State and Local Taxes	13,407	8.0	13,864	8.0	13,855	7.8
Total Taxes Charged to Income	$24,288	14.5 %	$25,932	15.0 %	$25,757	14.4 %

	1997		1998		1999p	
	Amount	% of Oper. Revenue	Amount	% of Oper. Revenue	Amount	% of Oper. Revenue
Federal Taxes						
Income	$10,166	5.8 %	$11,030	5.8 %	Data	%
Deferred Taxes on Income*	30	-	9,991	5.2	Not Available	
Other Deferred Income Taxes**	(431)	N/M	(9,772)	N/M	at time	
Miscellaneous Taxes	1,110	0.6	1,113	0.6	of Printing	
Total Federal Taxes Charged to Income	10,876	5.9	12,362	6.5		
State and Local Taxes	13,971	7.8	13,180	6.9		
Total Taxes Charged to Income	$24,848	13.6 %	$25,542	13.4 %		%

Note: Total may not equal sum of components due to independent rounding.
+Operating companies only as of 1996.
**Due to liberalized depreciation and accelerated amortization.*
***Includes investment tax credits reported as charges to income for the current year.*
( ) Denotes negative value. N/M Not Meaningful.
p Preliminary. Data for 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.

TABLE 75

Capitalization and Capitalization Ratios
Investor-Owned Electric Utilities

Millions of Dollars

	1994	1995	1996	1997	1998	1999p
CAPITALIZATION OUTSTANDING						
Mortgage Bonds	$122,135	$120,198	$120,797	$116,154	$99,287	
Other Long-Term Debt	52,432	54,816	60,467	81,244	95,762	
Total Long-Term Debt	174,567	175,014	181,265	197,398	195,030	Data
Preferred Stock	23,123	21,420	18,590	19,272	18,490	Not Available
Common Capital Stock	64,687	67,189	89,427	80,944	77,170	at time
Other Paid-In Capital Excluding Retained Earnings*	48,026	43,651	35,865	40,333	41,721	of Printing
Retained Earnings	56,352	58,213	57,379	66,161	66,362	
Total Capitalization	$364,755	$365,487	$382,528	$404,108	$398,773	
CAPITALIZATION RATIOS						
Mortgage Bonds	33.5 %	32.9 %	31.6 %	28.7 %	24.9 %	%
Other Long-Term Debt	14.4	15.0	15.8	20.1	24.0	
Total Long-Term Debt	47.9	47.9	47.4	48.8	48.9	
Preferred Stock	6.3	5.9	4.9	4.8	4.6	
Common Capital Stock Equity	45.8	46.3	47.8	46.4	46.5	
Total Capitalization	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	%

Note: Total may not equal sum of components due to independent rounding.

*Includes Premium on Common and Preferred Stock.

p Preliminary. Data for 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.

TABLE 76
Statement of Cash Flows
Investor-Owned Electric Utilities
Millions of Dollars

	1994	1995	1996	1997	1998	1999p
Operating Activities:						
Net Income	$18,972	$20,878	$21,482	$15,676	$17,551	
Noncash Items Included in Net Income:						
Depreciation, Depletion and Amortization	22,448	23,254	24,840	28,075	29,490	
Deferred Income Taxes (Net)	1,435	1,137	1,437	(163)	(1,191)	
Allowance for Funds Used During Construction (Equity)	(365)	(218)	(206)	(190)	(131)	
Other	(23)	2,088	1,347	1,975	421	
Changes in Working Capital:						Data
Materials and Supplies, Fuel Inventories, Gas in Storage	(254)	490	8	212	(389)	Not
Accounts Receivable (Net)	222	(1,563)	(687)	(2,563)	(674)	Available
Other Current Assets	864	109	(220)	3	(527)	at time
Accrued Taxes	(491)	11	(130)	128	362	of Printing
Accounts Payable and Other Current Liabilities	1,202	2,257	1,783	6,189	(581)	
Net Cash Provided By (Used For) Operating Activities	$44,009	$48,444	$49,652	$49,342	$44,332	
Investing Activities:						
Construction Expenditures (excl. AFUDC-Equity)	(26,965)	(24,089)	(22,267)	(25,636)	(27,369)	
Purchase of Other Investments	(1,649)	(2,239)	(6,917)	(13,689)	(7,928)	
Sale of Other Investments	838	941	1,454	1,166	9,732	
Other	(1,981)	(3,618)	(5,351)	(6,351)	(6,277)	
Net Cash Provided By (Used For) Investing Activities	($29,758)	($29,005)	($33,081)	($44,511)	($31,842)	
Financing Activities:						
Issuance of Common Stock (Net Proceeds)	2,135	1,357	1,796	3,846	3,557	
Issuance of Preferred/Preference Stock (Net Proceeds)	1,176	1,345	1,388	7,027	1,678	
Redemption of Preferred/Preference Stock (Net Payments)	(2,019)	(3,011)	(3,044)	(4,156)	(2,217)	
Redemption of Long-Term Debt (Net Proceeds)	(16,149)	(16,180)	(19,180)	(24,477)	(27,105)	
Common Stock Dividends	(15,212)	(15,500)	(14,968)	(14,972)	(14,253)	
Preferred/Preference Stock Dividends	(1,260)	(1,353)	(681)	(640)	(557)	
Issuance of Long-Term Debt (Net Proceeds)	15,552	15,639	18,153	30,037	33,462	
Increase (Decrease) in Short-Term Debt (Net)	1,092	1,725	2,479	4,698	11,498	
Other Financing	541	(1,613)	(1,319)	305	(12,161)	
Net Cash Provided By (Used For) Financing Activities	($14,144)	($17,592)	($15,375)	$1,668	($6,099)	
Net Increase (Decrease) in Cash and Cash Equivalents	$107	$1,847	$1,196	$6,499	$6,391	

Note: Total may not equal sum of components due to independent rounding.
( ) Denotes negative value.
p Preliminary. Data for 1999p not available at time of printing. Please check our web site at www.eei.org, or call the Statistics Department on 202-508-5572, for updates.

TABLE 77

Public Utility Long-Term Financing
Investor-Owned Electric Utilities

By Year, Type of Issue, Purpose and Type of Utility
1994-1999 - Thousands of Dollars

	1994	1995	1996	1997	1998	1999
			ELECTRIC UTILITIES			
Total Long-Term Debt	$7,840,104	$5,867,904	$5,752,065	$6,373,110	$16,485,552	$13,427,536
New Capital	5,750,002	3,376,637	3,004,165	5,488,110	9,215,430	10,176,334
Refunding	2,090,102	2,491,267	2,747,900	885,000	7,270,122	3,251,202
Total Preferred Stock	$1,119,500	$610,000	$483,500	$3,080,250	$2,238,605	$1,662,000
New Capital	1,069,500	610,000	383,500	2,930,250	1,079,000	612,000
Refunding	50,000	–	100,000	150,000	1,159,605	1,050,000
Total Common Stock	$1,149,870	$722,403	$954,477	$1,031,376	$2,310,017	$ –
New Capital	1,149,870	722,403	584,614	1,031,376	1,693,631	–
Refunding	–	–	369,863	–	616,386	–
TOTAL CAPITAL	$10,109,474	$7,200,307	$7,190,042	$10,484,736	$21,034,174	$15,089,536
New Capital	7,969,372	4,709,040	3,972,279	9,449,736	11,988,061	10,788,334
Refunding	2,140,102	2,491,267	3,217,763	1,035,000	9,046,113	4,301,202
			GAS UTILITIES*			
Total Long-Term Debt	$1,390,800	$970,000	$899,000	$1,922,000	$4,075,500	$1,554,600
New Capital	1,240,800	795,000	499,000	997,000	1,935,500	1,434,600
Refunding	150,000	175,000	400,000	925,000	2,140,000	120,000
Total Preferred Stock	$105,000	$238,750	$117,300	$547,500	$100,000	$ –
New Capital	30,000	238,750	117,300	547,500	100,000	–
Refunding	75,000	–	–	–	–	–
Total Common Stock	$270,438	$335,951	$403,699	$482,667	$2,239,825	$22,206
New Capital	270,438	302,801	403,699	365,667	2,236,525	22,206
Refunding	–	33,150	–	117,000	3,300	–
TOTAL CAPITAL	$1,766,238	$1,544,701	$1,419,999	$2,952,167	$6,415,325	$1,576,806
New Capital	1,541,238	1,336,551	1,019,999	1,910,167	4,272,025	1,456,806
Refunding	225,000	208,150	400,000	1,042,000	2,143,300	120,000
			ALL OTHER UTILITIES+			
Total Long-Term Debt	$4,536,600	$6,071,015	$9,493,806	$11,289,505	$22,522,760	$13,091,126
New Capital	2,086,600	1,676,015	5,545,200	8,354,108	15,982,760	10,591,126
Refunding	2,450,000	4,395,000	3,948,606	2,935,397	6,540,000	2,500,000
Total Preferred Stock	$102,300	$918,250	$1,145,000	$2,396,900	$1,082,500	$580,000
New Capital	102,300	918,250	1,145,000	2,096,900	1,082,500	580,000
Refunding	–	–	–	300,000	–	–
Total Common Stock	$361,550	$2,302,909	$3,296,540	$3,776,639	$2,116,350	$3,210,409
New Capital	361,550	2,302,909	2,667,478	3,776,639	804,350	2,347,809
Refunding	–	–	–	–	1,312,000	862,600
TOTAL CAPITAL	$5,000,450	$9,292,174	$13,935,346	$17,463,044	$25,721,610	$16,881,535
New Capital	2,550,450	4,897,174	9,357,678	14,227,647	17,869,610	13,518,935
Refunding	2,450,000	4,395,000	4,577,668	3,235,397	7,852,000	3,362,600
			TOTAL UTILITY FINANCING			
Total Long-Term Debt	$13,767,504	$12,908,919	$16,144,871	$19,584,615	$43,083,812	$28,073,262
New Capital	9,077,402	5,847,652	9,048,365	14,839,218	27,133,690	22,202,060
Refunding	4,690,102	7,061,267	7,096,506	4,745,397	15,950,122	5,871,202
Total Preferred Stock	$1,326,800	$1,767,000	$1,745,800	$6,024,650	$3,421,105	$2,242,000
New Capital	1,201,800	1,767,000	1,645,800	5,574,650	2,261,500	1,192,000
Refunding	125,000	–	100,000	450,000	1,159,605	1,050,000
Total Common Stock	$1,781,858	$3,361,263	$4,654,716	$5,290,683	$6,666,193	$3,232,615
New Capital	1,781,858	3,328,113	3,655,791	5,173,683	4,734,507	2,370,015
Refunding	–	33,150	998,925	117,000	1,931,686	862,600
TOTAL CAPITAL	$16,876,162	$18,037,182	$22,545,387	$30,899,948	$53,171,110	$33,547,877
New Capital	12,061,060	10,942,765	14,349,956	25,587,551	34,129,697	25,764,075
Refunding	4,815,102	7,094,417	8,195,431	5,312,397	19,041,413	7,783,802

*Classification as to type of utility is based upon predominant source of revenue. *Includes gas pipe line companies. +"Other Utilities" are water, transit, telephone does not include railroads. Note: Includes negotiated sales of pollution control bonds (in millions of dollars): 1999, $556; 1998, $551; 1997, $99; 1996, $1,790; 1995, $1,236; and 1994, $1,778. Source: PUFT, Inc. "Public Utility Financing Tracker."*

TABLE 78

Weighted Average of Yields on Newly Issued Domestic Bonds and Preferred Stocks

1979-1999

Year	Utility Bonds: Electric and Gas	Utility Bonds: Telephone	Utility Bonds: Water Works	Utility Bonds: All Utilities	Industrial Bonds	Preferred Stocks: All Utilities
1979	10.85 %	10.29 %	- %	10.84 %	9.49 %	9.76 %
1980	13.46	12.59	-	13.09	11.66	12.28
1981	16.31	15.45	-	16.30	15.16	15.11
1982	14.93	14.23	-	14.56	13.65	14.42
1983	12.70	11.72	-	12.53	11.50	12.06
1984	14.25	12.73	-	13.33	12.58	13.16
1985	11.83	11.54	11.18	11.78	11.64	10.08
1986	9.61	8.96	-	9.45	9.38	8.26
1987	9.74	9.63	-	9.75	9.29	7.83
1988	10.03	10.05	10.15	10.19	9.94	7.38
1989	9.92	8.68	-	9.27	9.51	9.24
1990	9.69	9.74	-	9.83	9.91	9.34
1991	9.06	8.95	8.89	9.03	9.15	8.22
1992	8.12	7.67	8.08	8.04	8.62	7.36
1993	N/A	N/A	N/A	N/A	7.54	N/A
1994	7.47	9.18	-	8.20	8.86	6.61
1995	7.82	7.33	7.87	7.75	7.80	N/A
1996	6.95	7.01	N/A	6.97	7.58	7.46
1997	N/A	N/A	N/A	N/A	N/A	N/A
1998	N/A	N/A	N/A	N/A	N/A	N/A
1999	N/A	N/A	N/A	N/A	N/A	N/A

N/A Not Available.
Source: Moody's Investors Service.

TABLE 79

Moody's Average Yields on Utility Bonds and Stocks

By Moody's Bond Ratings and Stock Quality Groups

1989-1999

	BONDS					PREFERRED STOCKS			COMMON STOCKS					
		Rating							High Quality		Good Quality		Medium Quality	
End of Month	Over-all* Quality	Aaa	Aa	A	Baa	aa High Quality	a Good Quality	baa Medium Quality	Yield	E/P Ratio**	Yield	E/P Ratio**	Yield	E/P Ratio**
1989														
December...	9.33	8.93	9.29	9.46	9.62	8.88	9.25	9.38	5.83	8.69	6.57	8.79	7.68	8.19
September..	9.48	9.15	9.42	9.59	9.77	8.91	9.43	9.73	6.47	9.00	7.08	8.05	8.01	9.11
June.......	9.36	9.01	9.26	9.53	9.64	8.93	9.37	9.73	6.41	9.15	7.25	7.79	8.14	9.77
March......	10.21	9.96	10.06	10.27	10.54	9.54	10.11	10.38	7.06	10.21	7.98	8.50	9.13	10.87
1990														
December...	9.58	9.18	9.43	9.73	9.99	9.08	9.30	9.54	6.60	8.75	6.84	6.62	7.89	6.62
September..	10.04	9.75	9.88	10.19	10.33	9.30	9.70	9.84	7.03	8.09	6.91	7.71	9.12	7.29
June.......	9.68	9.38	9.62	9.77	9.96	9.17	9.46	9.71	6.79	9.55	7.16	8.48	7.94	6.59
March......	9.79	9.51	9.70	9.84	10.10	9.18	9.47	9.63	6.53	9.47	7.18	9.00	8.46	7.22
1991														
December...	8.60	8.20	8.55	8.71	8.92	8.23	8.34	8.57	5.56	7.26	5.73	6.97	6.63	6.13
September..	8.95	8.58	8.91	9.07	9.25	8.39	8.59	8.82	5.96	8.07	6.13	7.52	7.16	8.07
June.......	9.42	9.13	9.28	9.54	9.72	8.77	8.89	9.19	7.08	8.98	6.79	8.37	7.92	8.31
March......	9.37	9.03	9.23	9.53	9.68	8.87	9.07	9.20	6.91	8.16	6.59	7.87	7.57	6.37
1992														
December...	8.30	7.93	8.26	8.38	8.62	7.88	8.16	8.53	5.41	6.59	6.07	7.20	6.56	7.68
September..	8.35	8.06	8.31	8.43	8.60	7.78	8.12	8.42	5.54	6.75	6.46	7.26	6.62	6.29
June.......	8.60	8.24	8.60	8.72	8.83	8.18	8.26	8.65	5.66	6.74	6.26	7.09	7.30	6.40
March......	8.82	8.41	8.78	8.94	9.15	8.18	8.32	8.65	6.02	7.34	7.14	7.50	7.33	6.29
1993														
December...	7.41	7.13	7.27	7.42	7.82	7.37	7.62	8.35						
September..	7.09	6.85	7.00	7.10	7.39	7.47	7.87	8.31	Not available					
June.......	7.57	7.31	7.44	7.58	7.95	7.62	8.08	8.38						
March......	7.88	7.65	7.76	7.94	8.18	7.70	8.06	8.41						
1994														
December...	8.83	8.59	8.72	8.79	9.20	8.17	8.65	9.22						
September..	8.80	8.57	8.69	8.79	9.17	7.73	8.25	8.85	Not available					
June.......	8.51	8.27	8.42	8.51	8.85	7.60	7.90	8.62						
March......	8.05	7.84	7.98	8.07	8.31	7.24	7.65	8.35						
1995														
December...	7.10	6.82	6.92	7.14	7.53	7.00	7.08	8.00						
September..	7.58	7.37	7.44	7.58	7.94	7.05	7.35	8.15	Not available					
June.......	7.67	7.45	7.54	7.64	8.04	7.08	7.45	8.23						
March......	8.39	8.17	8.28	7.36	8.76	7.42	7.91	8.55						
1996														
December...	7.56	7.30	7.43	7.57	7.95	6.92	6.96	8.15						
September..	7.88	7.63	7.71	7.89	8.28	7.17	7.21	8.12	Not available					
June.......	7.91	7.67	7.72	7.91	8.35	7.21	7.26	8.08						
March......	7.79	7.52	7.61	7.80	8.24	7.18	7.23	8.07						
1997														
December...	7.16	6.99	7.07	7.16	7.41	N/A	N/A	N/A						
September..	7.60	7.45	7.54	7.58	7.84	N/A	N/A	N/A	Not available					
June.......	7.77	7.55	7.68	7.72	8.12	6.67	6.95	8.20						
March......	7.92	7.70	7.84	7.87	8.26	6.98	7.01	8.12						
1998														
December...	6.84	6.43	6.78	6.91	7.24	6.23	6.50	7.37						
September..	6.88	6.66	6.78	6.93	7.13	5.49	5.75	6.52	Not available					
June.......	6.99	6.80	6.91	7.03	7.21	5.83	6.21	6.61						
March......	7.13	6.96	7.04	7.16	7.37	6.10	6.40	6.45						
1999														
December...														
September..	Not available					Not available			Not available					
June.......														
March......														

Note: Yields shown under preferred stocks and common stocks represent averages of ten companies in each quality group.
**Average yield for selected utility bonds in each of the four top quality ratings shown.*
***Ratio in percent is obtained by dividing earnings per share by market price per share.*
Source: Moody's Investors Service.

TABLE 80
Moody's 24 Utility Common Stocks
End-of-Month Averages

Year	Average	January	February	March	April	May	June	July	August	September	October	November	December
						MARKET PRICE - WEIGHTED AVERAGE - $ PER SHARE							
1987. . .	108.26	123.06	118.35	113.48	107.10	103.30	105.83	102.44	105.66	102.59	98.39	96.30	94.24
1988. . .	97.67	102.86	100.38	95.22	91.65	95.42	98.88	98.51	96.27	98.81	101.32	99.67	100.94
1989. . .	110.45	103.23	99.81	98.64	102.49	107.29	111.25	117.12	113.70	113.73	116.28	119.35	122.52
1990. . .	112.61	116.90	116.81	114.26	107.68	111.55	112.50	113.38	104.90	104.47	114.55	116.56	117.77
1991. . .	126.97	116.65	121.00	123.29	122.25	120.48	119.19	124.25	127.80	132.77	134.13	137.81	144.02
1992. . .	137.32	135.87	133.18	131.78	135.72	136.89	135.01	141.92	138.59	138.94	137.75	138.18	144.06
1993. . .	151.22	144.48	152.96	152.36	150.37	149.20	151.26	155.07	158.79	155.80	153.40	144.20	146.70
1994. . .	121.6	142.60	133.20	127.00	127.50	118.80	112.80	118.80	119.70	114.40	113.60	114.00	115.50
1995. . .	130.53	124.10	123.50	119.90	122.90	131.00	129.70	130.30	130.00	137.50	138.00	136.50	142.90
1996. . .	133.27	145.90	139.60	134.40	127.20	133.00	134.20	123.60	126.70	127.40	133.00	138.20	136.00
1997. . .	135.07	135.20	134.70	130.70	126.50	129.60	134.10	136.90	131.90	134.69	137.70	140.67	148.18
1998. . .	161.03	148.60	151.93	160.83	153.95	154.46	159.51	151.14	160.47	168.13	164.59	176.96	181.84
1999. . .						Not Available							
						DIVIDEND RATE - WEIGHTED AVERAGE - $ PER SHARE							
1987. . .	9.12	9.09	9.09	9.09	9.12	9.13	9.13	9.13	9.13	9.14	9.14	9.14	9.12
1988. . .	8.87	9.17	9.17	8.95	8.98	8.99	9.03	8.69	8.69	8.69	8.69	8.69	8.71
1989. . .	8.82	8.76	8.78	8.78	8.80	8.81	8.84	8.84	8.84	8.84	8.84	8.85	8.85
1990. . .	8.79	8.99	9.03	9.03	8.70	8.69	8.72	8.72	8.72	8.72	3.72	8.73	8.78
1991. . .	8.95	8.87	8.91	8.91	8.92	8.92	8.95	8.95	8.95	8.95	8.99	9.00	9.02
1992. . .	9.05	9.12	9.16	9.16	9.17	9.19	9.22	9.23	9.23	8.76	8.79	8.80	8.82
1993. . .	8.99	3.92	8.96	8.96	8.97	8.98	9.00	9.00	9.00	9.00	9.04	9.05	9.04
1994. . .	8.96	3.94	8.94	8.94	8.95	8.96	8.96	8.96	8.96	8.96	9.01	9.01	9.01
1995. . .	9.02	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.01	9.06	9.06	9.06
1996. . .	9.06	3.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06
1997. . .	9.06	9.06	3.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06	9.06
1998. . .	7.83	9.06	7.85	7.64	7.69	7.64	7.67	7.67	7.61	7.51	7.59	8.01	8.01
1999. . .						Not Available							
						YIELD - %							
1987. . .	8.58	7.39	7.68	8.01	8.50	8.88	8.63	8.91	8.64	8.91	9.29	9.49	9.68
1988. . .	9.08	8.92	9.14	9.40	9.80	9.42	9.32	9.00	9.03	8.79	8.58	8.72	8.63
1989. . .	8.02	8.49	8.80	8.90	8.59	8.21	7.95	7.55	7.77	7.77	7.60	7.42	7.22
1990. . .	7.82	7.69	7.73	7.90	8.08	7.79	7.75	7.69	8.31	8.35	7.61	7.49	7.44
1991. . .	7.07	7.60	7.36	7.23	7.30	7.40	7.51	7.20	7.00	6.74	6.70	6.53	6.26
1992. . .	6.61	6.71	6.88	6.95	6.76	6.71	6.83	6.50	6.66	6.30	6.38	6.37	6.25
1993. . .	5.95	6.17	5.86	5.88	5.97	6.02	5.95	5.80	5.67	5.78	5.87	6.27	6.16
1994. . .	7.41	6.32	6.71	7.04	7.02	7.54	7.94	7.54	7.49	7.83	7.93	7.90	7.80
1995. . .	6.93	7.26	7.30	7.52	7.33	6.88	6.95	6.92	6.93	6.55	6.57	6.64	6.34
1996. . .	6.81	6.21	6.49	6.74	7.12	6.81	6.75	7.33	7.15	7.11	6.81	6.56	6.67
1997. . .	6.72	6.72	6.93	6.93	7.16	6.99	6.76	6.62	6.87	6.52	6.58	6.44	6.12
1998. . .	4.88	6.10	5.17	4.75	5.00	4.95	4.81	5.07	4.74	4.47	4.61	4.53	4.40
1999. . .						Not Available							

Note: Quarterly earnings are for the 12 months ended March 31, June 30, September 30 and December 31.
Source: Moody's Investors Service.

SECTION X
Economics and Other

TABLE 82
Consumer Price Index, 1979-1999
1982-84 Equals 100

	All Items		Food and Beverages		Housing	
Year	Index	Percent Change	Index	Percent Change	Index	Percent Change
1979	72.6	11.3	79.9	10.7	70.1	12.3
1980.	82.4	13.5	86.7	8.5	81.1	15.7
1981.	90.9	10.3	93.5	7.8	90.4	11.5
1982.	96.5	6.2	97.3	4.1	96.9	7.2
1983.	99.6	3.2	99.5	2.3	99.5	2.7
1984.	103.9	4.3	103.2	3.7	103.6	4.1
1985.	107.6	3.6	105.6	2.3	107.7	4.0
1986.	109.6	1.9	109.1	3.3	110.9	3.0
1987.	113.6	3.6	113.5	4.0	114.2	3.0
1988.	118.3	4.1	118.2	4.1	118.5	3.8
1989.	124.0	4.8	124.9	5.7	123.0	3.8
1990.	130.7	5.4	132.1	5.8	128.5	4.5
1991.	136.2	4.2	136.8	3.6	133.6	4.0
1992.	140.3	3.0	138.7	1.4	137.5	2.9
1993.	144.5	3.0	141.6	2.1	141.2	2.7
1994.	148.2	2.6	144.9	2.3	144.8	2.5
1995.	152.4	2.8	148.9	2.8	148.5	2.6
1996.	156.9	3.0	153.7	3.2	152.8	2.9
1997.	160.5	2.3	157.7	2.6	156.8	2.6
1998.	163.0	1.6	161.1	2.2	160.4	2.3
1999.	166.6	2.2	164.6	2.2	163.9	2.2

	Transportation		Gas and Electricity		Electricity	
Year	Index	Percent Change	Index	Percent Change	Index	Percent Change
1979	70.5	14.3	61.0	10.9	65.6	7.7
1980.	83.1	17.9	71.4	17.0	75.8	15.5
1981.	93.2	12.2	81.9	14.7	87.2	15.0
1982.	97.0	4.1	93.2	13.8	95.8	9.9
1983.	99.3	2.4	101.5	8.9	98.9	3.2
1984.	103.7	4.4	105.4	3.8	105.3	6.5
1985.	106.4	2.6	107.1	1.6	108.9	3.4
1986.	102.3	(3.9)	105.7	(1.3)	110.4	1.4
1987.	105.4	3.0	103.8	(1.8)	110.0	(0.4)
1988.	108.7	3.1	104.6	0.8	111.5	1.4
1989.	114.1	5.0	107.5	2.8	114.7	2.9
1990.	120.5	5.6	109.3	1.7	117.4	2.4
1991.	123.8	2.7	112.6	3.0	121.8	3.7
1992.	126.5	2.2	114.8	2.0	124.2	2.0
1993.	130.4	3.1	118.5	3.2	126.7	2.0
1994.	134.3	3.0	119.2	0.6	126.7	0.0
1995.	139.1	3.6	119.2	0.0	129.6	2.3
1996.	143.0	2.8	122.1	2.4	131.9	1.8
1997.	144.3	0.9	125.1	2.5	132.5	0.5
1998.	141.6	(1.9)	121.2	(3.1)	127.4	(3.8)
1999.	144.4	2.0	120.9	(0.2)	126.5	(0.7)

( ) Denotes negative value. r Revised.
Source: U.S. Department of Labor. Bureau of Labor Statistics. Monthly Labor Review.

TABLE 83
Producer Price Index - Finished Goods and Selected Industrial Commodities
1982 Equals 100

Year	Finished Goods Index	Finished Goods Percent Change	Metals and Metal Products Index	Metals and Metal Products Percent Change	Machinery and Equipment Index	Machinery and Equipment Percent Change	Furniture and Household Durables Index	Furniture and Household Durables Percent Change	Fuels and Related Products and Power Index	Fuels and Related Products and Power Percent Change
1979. . .	77.6	11.2	86.0	14.2	76.7	9.1	82.8	6.8	58.9	26.7
1980. . .	88.0	13.4	95.0	10.5	86.0	12.1	90.7	9.5	82.8	40.6
1981. . .	96.1	9.2	99.6	4.8	94.4	9.8	95.9	5.7	100.2	21.0
1982. . .	100.0	4.1	100.0	0.4	100.0	5.9	100.0	4.3	100.0	(0.2)
1983. . .	101.6	1.6	101.8	1.8	102.7	2.7	103.4	3.4	95.9	(4.1)
1984. . .	103.7	2.1	104.8	2.9	105.1	2.3	105.7	2.2	94.8	(1.1)
1985. . .	104.7	1.0	104.4	(0.4)	107.2	2.0	107.1	1.3	91.4	(3.6)
1986. . .	103.2	(1.4)	103.2	(1.1)	108.8	1.5	108.2	1.0	69.8	(23.6)
1987. . .	105.4	2.1	107.1	3.8	110.4	1.5	109.9	1.6	70.2	0.6
1988. . .	108.0	2.5	118.7	10.8	113.2	2.5	113.1	2.9	66.7	(5.0)
1989. . .	113.6	5.2	124.1	4.5	117.4	3.7	116.9	3.4	72.9	9.3
1990. . .	119.2	4.9	122.9	1.0	120.7	2.8	119.2	2.0	82.3	12.9
1991. . .	121.7	2.1	120.2	(2.2)	123.0	1.9	121.2	1.7	81.2	(1.3)
1992. . .	123.2	1.2	119.2	(0.8)	123.4	0.3	122.2	0.8	80.4	(1.0)
1993. . .	124.7	1.2	119.2	0.0	124.0	0.5	123.7	1.2	80.0	(0.5)
1994. . .	125.5	0.6	124.8	4.7	125.1	0.9	126.1	1.9	77.8	(2.8)
1995. . .	127.9	1.9	134.5	7.8	126.6	1.1	128.2	1.6	78.0	0.1
1996. . .	131.3	2.7	131.0	(2.6)	126.5	(0.1)	130.4	1.7	85.8	10.0
1997. . .	131.8	0.4	131.8	0.6	125.9	(0.5)	130.8	0.3	85.9	0.1
1998r. . .	130.7	(0.8)	127.8	(3.0)	124.9	(0.8)	131.3	0.4	75.3	(12.3)
1999p. . .	133.1	1.8	124.6	(2.5)	124.3	(0.5)	131.7	0.3	80.6	7.0

Year	Coal Index	Coal Percent Change	Gas Fuels Index	Gas Fuels Percent Change	Electric Power Index	Electric Power Percent Change	Crude Petroleum Index	Crude Petroleum Percent Change	Petroleum Products, Refined Index	Petroleum Products, Refined Percent Change
1979. . .	84.3	4.9	51.3	27.0	66.5	8.0	51.3	25.4	58.4	38.4
1980. . .	87.4	3.7	71.7	39.8	79.1	18.9	75.9	48.0	88.6	51.7
1981. . .	93.0	6.4	88.6	23.6	90.3	14.2	109.6	44.4	105.9	19.5
1982. . .	100.0	7.5	100.0	12.9	100.0	10.7	100.0	(8.8)	100.0	(5.6)
1983. . .	100.5	0.5	108.1	8.1	102.8	2.8	92.9	(7.1)	89.9	(10.1)
1984. . .	102.2	1.7	104.5	(3.3)	108.2	5.3	91.3	(1.7)	87.4	(2.8)
1985. . .	102.2	0.0	98.7	(5.6)	111.6	3.1	84.5	(7.4)	83.2	(4.8)
1986. . .	100.8	(1.4)	83.2	(15.7)	112.6	0.9	46.9	(44.5)	53.2	(36.1)
1987. . .	97.1	(3.7)	74.1	(10.9)	110.6	(1.8)	55.5	18.3	56.8	6.8
1988. . .	95.4	(1.8)	71.4	(3.6)	111.2	0.5	46.2	(16.8)	53.9	(5.1)
1989. . .	95.5	0.1	75.3	5.5	114.8	3.2	56.3	21.9	61.2	13.5
1990. . .	97.5	2.1	78.4	4.1	117.6	2.4	71.0	26.1	74.8	22.2
1991. . .	97.2	(0.3)	77.0	(1.8)	124.3	5.7	61.9	(12.8)	67.2	(10.2)
1992. . .	95.0	(2.3)	75.9	(1.4)	126.3	1.6	58.0	(6.3)	64.7	(3.7)
1993. . .	96.1	1.2	78.5	3.4	128.6	1.8	51.4	(11.4)	62.0	(4.2)
1994. . .	96.7	0.6	72.8	7.3	128.7	0.1	47.1	(8.4)	59.1	(4.7)
1995. . .	95.0	(1.9)	65.2	(11.0)	130.9	1.7	51.1	8.3	60.8	2.5
1996. . .	94.5	(0.5)	88.3	35.4	131.6	0.5	62.6	22.5	70.1	15.3
1997. . .	96.0	1.6	95.1	7.7	131.5	(0.1)	57.5	(8.1)	67.9	(3.1)
1998r. . .	93.6	(2.5)	76.6	(19.5)	129.9	(1.2)	35.7	(37.9)	51.3	(24.4)
1999p. . .	90.5	(3.3)	85.4	11.5	129.0	(0.7)	50.3	40.9	60.9	18.7

p Preliminary. r Revised.
( ) Denotes negative value.
Source: U.S. Department of Labor, Bureau of Labor Statistics, Producer Price Indexes.

TABLE 88

Circuit Miles of Overhead Electric Line of 22,000 Volts and Above in Service - Total Electric Utility Industry

By State and Voltage Groups

State/Division	Circuit Miles 1998p	1997	1996
Total United States*.	**714,477**	**711,438**	**703,095**
Maine	3,843	3,885	3,870
New Hampshire	2,706	2,706	2,756
Vermont	2,151	2,144	2,146
Massachusetts	6,528	6,509	6,608
Rhode Island	628	648	702
Connecticut	3,025	3,025	3,056
New England	**18,881**	**18,914**	**19,138**
New York	20,795	20,786	21,464
New Jersey	6,771	6,756	6,787
Pennsylvania	31,503	30,253	26,343
Middle Atlantic	**59,070**	**57,794**	**54,594**
Ohio	24,663	24,725	24,643
Indiana	16,081	16,179	16,138
Illinois	21,042	20,744	20,164
Michigan	25,526	26,373	26,507
Wisconsin	12,276	12,489	12,514
East North Central	**99,588**	**100,510**	**99,967**
Minnesota	9,835	10,038	10,033
Iowa	13,806	13,913	14,066
Missouri	11,409	11,319	11,649
North Dakota	7,638	7,641	7,641
South Dakota	8,353	8,353	8,357
Nebraska	15,607	15,546	15,567
Kansas	10,443	10,440	10,392
West North Central	**77,090**	**77,251**	**77,705**
Delaware	5,860	5,710	5,699
Maryland	6,994	6,994	6,971
District of Columbia	10	10	10
Virginia	15,402	15,335	15,246
West Virginia	9,488	9,465	9,414
North Carolina	27,117	27,613	27,683
South Carolina	22,193	22,130	22,212
Georgia	31,248	31,239	31,056
Florida	19,662	19,434	19,351
South Atlantic	**137,975**	**137,930**	**137,641**
Kentucky	10,148	10,097	10,049
Tennessee	23,371	22,767	22,538
Alabama	22,108	22,051	22,327
Mississippi	6,912	6,797	6,849
East South Central	**62,539**	**61,712**	**61,763**
Arkansas	8,150	8,110	7,962
Louisiana	13,484	13,237	13,366
Oklahoma	9,911	9,911	9,909
Texas	66,759	65,673	62,452
West South Central	**98,304**	**96,931**	**93,689**
Montana	10,927	10,988	10,968
Idaho	13,677	13,346	13,393
Wyoming	6,519	6,540	6,508
Colorado	8,147	8,274	8,289
New Mexico	8,203	8,201	8,103
Arizona	15,146	15,120	14,441
Utah	8,105	8,103	8,103
Nevada	8,751	8,403	8,356
Mountain	**79,475**	**78,974**	**78,161**
Washington	20,486	20,350	20,229
Oregon	12,184	12,090	12,099
California	46,163	46,313	45,440
Pacific	**78,833**	**78,753**	**77,768**
Alaska	824	770	769
Hawaii	1,899	1,899	1,899
Alaska & Hawaii	**2,723**	**2,669**	**2,668**

Note: Total may not equal sum of components due to independent rounding.
**Does not include miles of line operated by cooperatives.*
p Preliminary.

Nominal Voltage	Circuit Miles 1998p	1997	1996
Total	**714,477**	**711,438**	**703,095**
22,000- 30,000	104,713	103,740	101,213
31,000- 40,000	107,782	105,965	103,252
41,000- 50,000	51,302	51,349	51,390
51,000- 70,000	108,113	107,746	108,070
71,000-131,000	97,025	96,787	95,181
132,000-143,000	70,896	70,493	70,150
144,000-188,000	25,432	25,387	25,120
189,000-253,000	71,175	69,696	68,670
254,000-400,000	46,865	49,338	49,829
401,000-600,000	28,436	28,218	27,657
601,000-800,000	2,738	2,721	2,561

1998 revised and 1999 preliminary data not available.

Please see the next page for line data from the North American Electric Reliability Council

TABLE 87

Circuit Miles of Overhead Electric Line of 22,000 Volts and Above in Service - Investor-Owned Electric Utilities

By State and Voltage Groups

State/Division	Circuit Miles 1998p	1997	1996
Total United States*	577,884	576,508	569,446
Maine	3,816	3,858	3,843
New Hampshire	2,706	2,706	2,756
Vermont	2,038	2,031	2,030
Massachusetts	6,131	6,113	6,212
Rhode Island	628	646	702
Connecticut	2,991	2,991	3,023
New England	18,311	18,346	18,566
New York	18,090	18,080	18,759
New Jersey	6,762	6,746	6,778
Pennsylvania	31,415	30,165	26,255
Middle Atlantic	56,267	54,991	51,791
Ohio	23,889	23,944	23,863
Indiana	15,377	15,484	15,440
Illinois	20,639	20,342	19,765
Michigan	25,252	26,093	26,230
Wisconsin	12,059	12,271	12,296
East North Central	97,215	98,135	97,594
Minnesota	9,112	9,292	9,289
Iowa	11,380	11,584	11,734
Missouri	10,481	10,410	10,744
North Dakota	5,581	5,585	5,584
South Dakota	4,194	4,195	4,192
Nebraska	94	94	94
Kansas	10,161	10,158	10,104
West North Central	51,004	51,317	51,740
Delaware	5,635	5,635	5,624
Maryland	6,978	6,978	6,955
District of Columbia	10	10	10
Virginia	14,930	14,867	14,777
West Virginia	9,488	9,465	9,414
North Carolina	26,315	26,828	26,903
South Carolina	18,571	18,553	18,632
Georgia	29,191	29,184	29,072
Florida	14,195	14,147	14,099
South Atlantic	125,313	125,666	125,486
Kentucky	8,069	7,999	7,961
Tennessee	326	316	316
Alabama	18,903	18,855	19,124
Mississippi	4,875	4,774	4,857
East South Central	32,173	31,945	32,259
Arkansas	7,508	7,468	7,323
Louisiana	13,347	13,113	13,242
Oklahoma	8,228	8,233	8,230
Texas	59,596	58,662	55,479
West South Central	88,678	87,475	84,274
Montana	8,169	8,196	8,176
Idaho	12,675	12,396	12,444
Wyoming	4,391	4,412	4,381
Colorado	5,181	5,311	5,283
New Mexico	7,896	7,902	7,808
Arizona	7,378	7,352	7,352
Utah	7,671	7,671	7,671
Nevada	7,400	7,192	7,164
Mountain	60,763	60,432	60,280
Washington	4,567	4,551	4,523
Oregon	5,916	5,856	5,877
California	35,613	35,785	35,047
Pacific	46,096	46,192	45,446
Alaska	166	111	111
Hawaii	1,899	1,899	1,899
Alaska & Hawaii	2,065	2,010	2,010

Note: Total may not equal sum of components due to independent rounding.
**Does not include miles of line operated by cooperatives.*
p Preliminary.

Nominal Voltage	Circuit Miles 1998p	1997	1996
Total	577,884	576,508	569,446
22,000- 30,000	79,577	79,547	77,165
31,000- 40,000	98,216	98,527	93,678
41,000- 50,000	47,851	47,878	47,893
51,000- 70,000	86,992	86,939	87,324
71,000-131,000	77,668	77,898	76,464
132,000-143,000	65,544	65,194	64,896
144,000-188,000	10,369	10,383	10,253
189,000-253,000	51,867	51,342	50,603
254,000-400,000	39,632	40,684	41,270
401,000-600,000	17,588	17,550	17,495
601,000-800,000	2,583	2,566	2,406

1998 revised and 1999 preliminary data not available.

TABLE 88

Number of Electric Department Employees

Investor-Owned Electric Utilities

Year	Average	At December 31	Year	Average	At December 31
1986.	529,684	533,842	1993.	491,730	484,728
1987.	523,868	528,484	1994.	468,453	454,219
1988.	522,362	520,762	1995.	N/A*	441,134
1989.	518,584	513,534	1996.	N/A*	417,870
1990.	511,701	510,585	1997.	N/A*	403,964
1991.	510,016	507,820	1998r	N/A*	358,882
1992.	506,058	498,334	1999p	N/A*	334,381

r Revised.
p Preliminary.
**Beginning in 1995, average employee data is no longer available.*

Reliability Assessment

2000–2009

The Reliability of

Bulk Electric Systems

in North America

North American Electric Reliability Council

October 2000

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About This Report

The North American Electric Reliability Council (NERC) Board of Trustees formed the Reliability Assessment Subcommittee (RAS) in 1970 to annually review the overall reliability of existing and planned electric generation and transmission systems of the Regional Councils.

This *Reliability Assessment 2000–2009* report presents:

- an assessment of electric generation and transmission reliability through 2009,
- an assessment of the generation resource adequacy of each Interconnection in North America,
- a discussion of key issues affecting reliability of future electric supply, and
- Regional assessments of electric supply reliability, including issues of specific Regional concern.

This report reflects the expertise, judgment, and interpretations of the RAS members. In preparing this report, RAS:

- reviewed summaries of Regional self assessments, including forecasts of peak demand, energy requirements, and planned resources,
- appraised Regional plans for new electric generation resources and transmission facilities, and
- assessed the potential effects of changes in technology, market forces, legislation, regulations, and governmental policies on the reliability of future electric supply.

The data in this report reflects conditions that were projected as of June 15, 2000. Detailed background data is available in NERC's *Electricity Supply & Demand* (ES&D) database, 2000 edition.

The majority of new generation additions over the next few years are expected to be constructed by the rapidly growing merchant generation industry. NERC is collaborating with the Electric Power Supply Association (EPSA) to capture as much information regarding merchant plant additions as possible. In some cases, data available from EPSA is used in this report to supplement data submitted by the Regions.

Assessment Time Frame

RAS views this ten-year assessment in two time frames: the near term, consisting of the first five years and the long term, which is the balance of the ten-year period. While the near-term represents a fairly accurate forecast of future conditions, the longer-term assessment must be considered more an indication of future trends than an absolute. Assessing reliability beyond the near term is extremely difficult because of the level of uncertainty and quality of information provided for modeling and analysis. The uncertainty in the data is due primarily to the reluctance of some industry participants to establish long-term firm energy commitments in light of an uncertain future or to reveal future plans for competitive reasons. Similarly, transmission plans projected more than five years in the future are tentative because justification studies usually have not been completed and regulatory approvals have not been received.

About NERC

On November 9, 1965, a blackout left 30 million people across the Northeastern United States and Ontario, Canada in the dark. In an effort to prevent this type of blackout from ever happening again, electric utilities formed the North American Electric Reliability Council (NERC) in 1968 to promote the reliability of the electricity supply for North America. This mission is accomplished by working with all segments of the electric industry as well as customers. NERC reviews the past for lessons learned, monitors the present for compliance with policies, standards, principles, and guides, and assesses the future reliability of the bulk electric systems.

FOREWORD

NERC's members are ten Regional Councils encompassing virtually all of the electric systems in the continental United States, Canada, and the northern portion of Baja California Norté, Mexico. The members of these Regional Councils come from all segments of the electric industry — investor-owned, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, and power marketers.

NERC is in the process of transforming itself into a self-regulatory reliability organization (SRRO) that will have the responsibility and authority to set and enforce compliance with mandatory standards for the interconnected bulk electric systems that apply throughout North America.

Since 1968, NERC has relied entirely on voluntary efforts and "peer pressure" to ensure compliance with its standards. This voluntary arrangement is simply no longer adequate. The users and operators of the system who used to cooperate voluntarily on reliability matters are now competitors without the same incentives to cooperate with each other or comply with voluntary reliability rules. Little or no effective recourse exists today under the current voluntary model to correct such behavior. No single bulk electric system reliability standard can be enforced effectively today by NERC or the Federal Energy Regulatory Commission (FERC). FERC is being asked to make decisions on reliability issues for which it lacks both the technical expertise and clear statutory authority.

Reliability rules must be made mandatory and enforceable, and fairly applied to all participants in the electricity market. To meet this need, NERC and a broad coalition of industry organizations have proposed the creation of a single, industry-based SRRO to develop and enforce mandatory reliability rules with FERC oversight in the United States to ensure the SRRO and its affiliated Regional reliability entities operate effectively and fairly. The proposal follows the model of the Securities and Exchange Commission in its oversight of the securities industry self-regulatory organizations (the stock exchanges and the National Association of Securities Dealers). As the industry evolves toward full competition, the SRRO will have to examine traditional reliability planning practices and policies to ensure that they are still applicable and that they continue to result in reliable electric systems.

Near Term (2000–2004)

Near term generation adequacy is deemed satisfactory, provided new generating facilities are constructed as anticipated. After several years of decline, projected capacity margins show a marked increase over the first five years of the assessment period, as merchant generation developers respond to price signals and other indicators of market opportunities. While electricity demand is anticipated to grow by approximately 60,500 MW in the near term, new resource additions totaling from about 109,000 to 193,000 MW are projected over the same period depending upon the number of merchant plant projects that are assumed to be in service. This would result in a range of capacity margins from 15% to as much as 27% in the United States over this time frame. NERC, the Electric Power Supply Association (EPSA), and the Regions are taking steps to address data collection issues related to projected merchant power plant facility additions.

In the near term, the transmission system is expected to operate satisfactorily. However, a reliable level of operation will be highly dependent upon continually increasing coordination with surrounding systems and proper transmission system operator actions. Transmission congestion will worsen and as a result, transactions will continue to be curtailed until other appropriate congestion relief methods are implemented. The continuing upward trend of NERC Transmission Loading Relief procedures (TLRs), during a relatively mild summer in the Eastern Interconnection, is indicative of the persistence of congestion in various areas of the transmission system. Few major transmission system facility additions are planned for the near term. As competitive electricity markets continue to develop, it is likely that the transmission system will be operated at levels of power flows and in configurations not previously experienced.

The ability to transfer electric energy across some interfaces is at times hampered by insufficient reactive power support. It is imperative that reactive support enhancements keep pace with the demands being placed on the transmission systems to maintain reliability. Distribution systems also must maintain adequate reactive power support to keep air conditioning and other inductive demands from creating voltage problems on the transmission system. Reactive power support must be planned and coordinated among generation, transmission, and distribution. To accommodate the widely varying flow patterns and associated reactive demands that have become commonplace with open-access transmission use, the reactive support systems also must be far more versatile.

Customer demand has continued to grow and actual demand growth rates experienced over the past few years have been significantly higher than the current base projections. A strong economy in North America coupled with hotter than expected weather at peak times has driven electric demand and energy to grow faster than projected.

Long Term (2005–2009)

Long term generation adequacy is more difficult to assess than the near term, but if current trends continue, long-term adequacy will also be satisfactory. This adequacy is dependent upon the continued response of merchant power plant developers to market signals to construct new generating facilities (and their ability to obtain the necessary siting approvals) in areas with declining capacity margins. Timing of new capacity additions will continue to be critical. Capacity additions are increasingly being driven by market signals and not the maintenance of a prescribed capacity margin. This will likely lead to fluctuations in capacity margins that reflect normal business cycles experienced in other industries.

The reliability of the interconnected transmission systems in the long term will be highly dependent upon the location of new generating resources. Unless proper incentives can be developed to encourage investment in new transmission facilities and siting problems can be resolved, few new transmission facilities and reinforcements will be constructed. The lack of necessary additional transmission facilities and reinforcements will require that either new technologies be developed to alleviate transmission congestion or that generating facilities be located and dispatched in a manner to minimize the use of constrained transmission corridors. The close coordination of generation and transmission planning that resulted in the highly reliable electric systems of North America must now be accomplished through different means and coordinated among many different entities. Market demand signals and regulatory factors will dictate the location and timing of generation capacity additions, and will also influence the planning of needed transmission additions.

Definition of Reliability

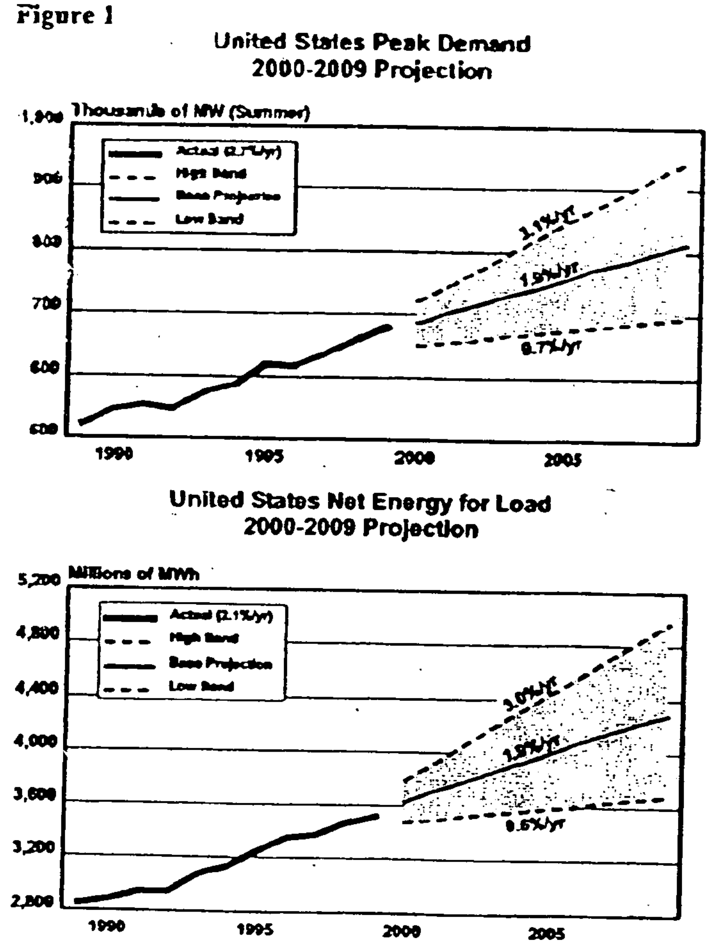
NERC defines the reliability of the interconnected bulk electric systems in terms of two basic, functional aspects:

1. Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
2. Security — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Demands and Resources

The average annual peak demand growth over the next ten years is projected to be a relatively modest 1.9% for demand and 1.9% for energy use in the United States (Figure 1). The projected growth in demand is similar to the projections of the last several years. Both projections are substantially below the actual growth rates experienced over the last ten years as demand continues to be driven by extreme weather at peak times and a strong economy. High and low bands around the base forecast show a range of the forecast uncertainty to account for weather, economic growth, industry deregulation, and other industry issues. Actual demand and energy growth rates experienced in the United States over the last ten years have been significantly higher than the current base projection and have actually been closer to the rate calculated as the high band for both demand and energy.

Figure 1



Forecast Bandwidths

Forecasts cannot precisely predict the future. Instead, many forecasts attach probabilities to the range of possible outcomes. Each base demand projection, for example, represents the midpoint of possible future outcomes. This means that a future year's actual demand has a 50% chance of being higher and a 50% chance of being lower than the forecast value. Capacity resources are planned for the 50% demand projections.

For planning purposes, it is useful to have an estimate not only of the midpoint of possible future outcomes, but also of the distribution of probabilities on both sides of that midpoint. Accordingly, NERC's Load Forecasting Working Group develops upper and lower 80% confidence bands around the NERC-aggregated demand projections. Therefore, there is an 80% chance of future demand occurring within these bands, a 10% chance of future demand occurring below the lower band, and an equal 10% chance of future demand occurring above the upper band.

ASSESSMENT OF RELIABILITY

Uncertainty in the demand forecast projected by the NERC Load Forecasting Working Group (LFWG) has shifted and increased the range of the bandwidths from 1.2 to 2.4% last year to 0.7 to 3.1% this year. Similar increases in energy growth rate uncertainty are reflected in the shifted bandwidth range from 1.2 to 2.4% last year to 0.6 to 3.0% this year.

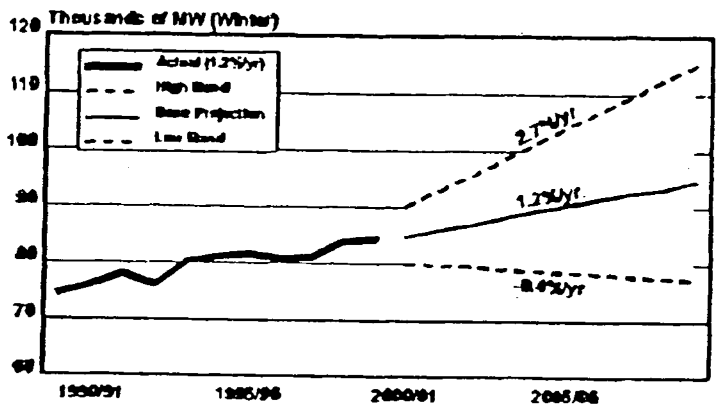
The projected ten-year peak demand growth rate in Canada of 1.2% (Figure 2) is equal to that experienced in Canada over the last ten years. Energy growth in Canada is projected to be 1.3%, equal to the growth rate experienced over the last ten years. Forecast uncertainty is shown by the bandwidths around the base forecasts in Figure 2.

As in the United States, uncertainty in the demand forecast has increased the range of the LFWG forecast bandwidths from 0.0 to 2.7% last year to -0.4 to 2.8% this year. Similar increases in Canada's energy growth rate uncertainty are reflected in the increased bandwidth range from 0.0 to 3.0% last year to 0.4 to 2.8% this year.

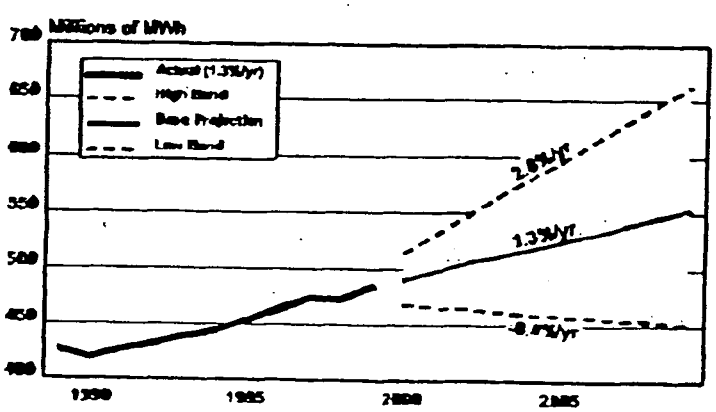
The method of developing and reporting demand forecasts will undergo major revisions to keep pace with the evolving market. Demand forecast data collection is addressed further in the Reliability Issues section of this report.

Figure 2

Canada Peak Demand
2000/01-2009/10 Projection



Canada Net Energy for Load
2000-2009 Projection



Resource Adequacy Assessment

Capacity adequacy in North America over the next ten years will be highly dependent upon the construction of new generation resources and innovative use of controllable demand-side resources. Most of the new generation is expected to be constructed by merchant developers. Merchant generators have announced plans for over 191,000 MW[1] of new capacity over the ten-year period. While some of that merchant capacity was included in the capacity margins reported to NERC by its Regions, much was not.

Projected capacity margins in the United States show a sharp increase from 2000 to 2004, reaching over 18%, as merchant capacity continues to come on line to serve growing demand. The margin erodes during later years to less than 14% as demand continues to grow and reported capacity additions dwindle. Margins in this assessment show a marked improvement over those of the assessments of the past three years, due mostly to the amount of new merchant capacity projected to come on line. Although the aggregate capacity margin for the United States appears adequate, there may still be isolated pockets of the country that may experience capacity shortfalls due to local limitations to generate or import power.

Figure 3

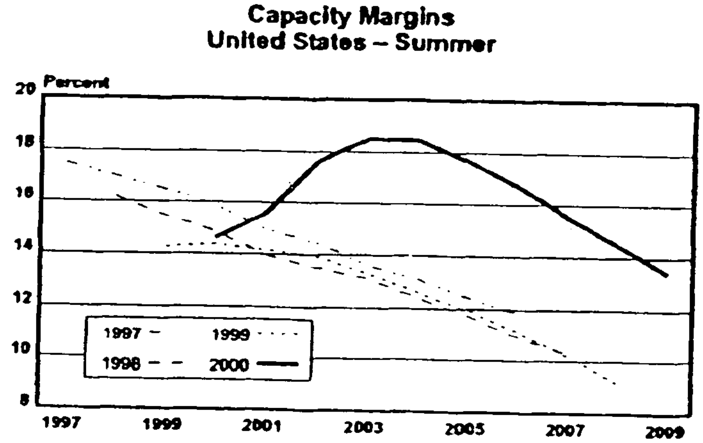


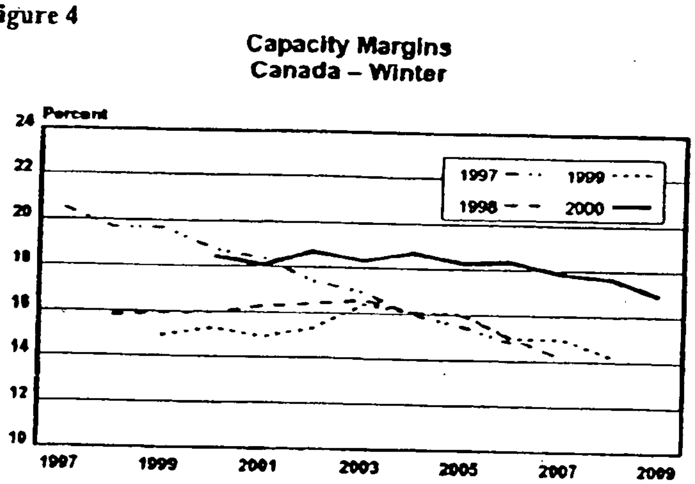
Figure 3 shows the capacity margins as reported to NERC by the member Regions. The impacts of differing levels of merchant capacity additions upon projected capacity margins are depicted in subsequent areas of this report. As merchant generation is completed, it will serve to increase the reported margins. The data reported by the Regions represents their best estimate of projected new resource additions, balancing the amount of announced new merchant plants with the likelihood of each project actually being built and meeting its target in service date.

Resource planning is changing in the United States as the industry restructures. Generation developers are primarily driven by financial incentives and not the maintenance of resource planning margins. Shifting incentives coupled with short lead times to construct new generating facilities, make the near term projected capacity margin increases more understandable. The fact that few capacity additions are indicated beyond 2004, does not mean that additions will not occur, but rather that these decisions have not yet been made or are being withheld for competitive reasons.

1 - As reported by EPSA as of June 15, 2000. Further amounts of new merchant capacity announcements have been made since that time.

The profile of the projected Canadian capacity margins (Figure 4) has improved compared to the recent past and is projected to remain relatively flat, at approximately 18%. It is important to note that the Canadian systems reach their aggregate peak demand levels in winter.

Figure 4

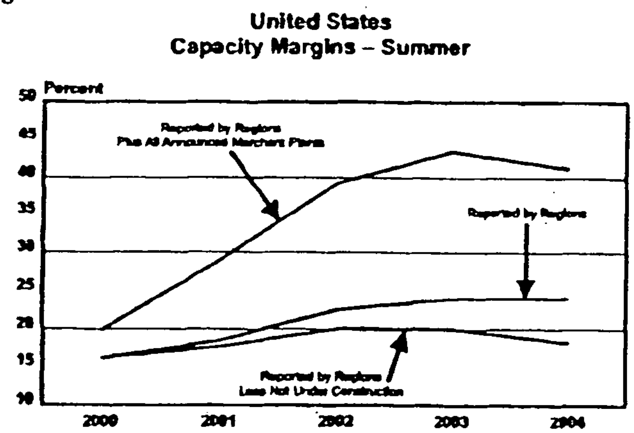


The market has begun to respond in areas of capacity deficiencies, as evidenced by over 20,000 MW of new merchant capacity that came on line to serve demand in the United States this past summer. Merchant generation will continue to play a major role in the future power supply of North America, as shown in Figure 4. Additional information on announced merchant generation capacity additions, compiled by the Electric Power Supply Association (EPSA), was used in this report to gauge the level of reliance on new merchant capacity. EPSA is tracking plans for over 190,000 MW[2] of merchant generation additions that have been announced for construction in the United States by the end of 2004. About 111,000 MW of new merchant capacity is planned before the end of 2002. About 78,000 MW of the total is in the Eastern Interconnection, with about 16,000 MW in the ERCOT Interconnection and about 16,000 MW in the Western Interconnection. Although not all of that capacity is assured of being constructed, it is obvious that its impact on future reliability will be critical.

Figure 5 illustrates the possible range of projected capacity margins for the United States over the next five years. Since it is difficult to accurately predict the exact number and in-service dates of future capacity additions merchant developers will actually construct, this report provides the reader with a range of potential values. The announcement of a new merchant generating facility does not necessarily guarantee its construction, for a variety of reasons, including market prices, the ability to obtain suitable interconnection and transmission access agreements, the ability to obtain financial backing and other typical business factors. In some cases, a single developer may announce several projects, even though only one will be built. Such announcements are made because developers cannot be assured of obtaining all the necessary permits to build, forcing them to alternate locations as a contingency plan. In other cases, economic conditions may change, making a project unprofitable and leading to its cancellation. For example, the recent increase in natural gas prices may cause developers to review previously announced plans for generation construction. Regardless, the Figure clearly illustrates that projected generating resources should be adequate to serve the overall demand in the United States, even if only 50% of the announced plants come to fruition. Even though the overall capacity will be adequate to serve demand, there may be pockets of North America that may experience deficiencies as new resources come on line to meet demand or if transmission limitations prevent the delivery of energy to demand centers.

2 - All EPSA generation values are as of June 15, 2000. Further amounts of new merchant capacity announcements have been made since that time.

Figure 5

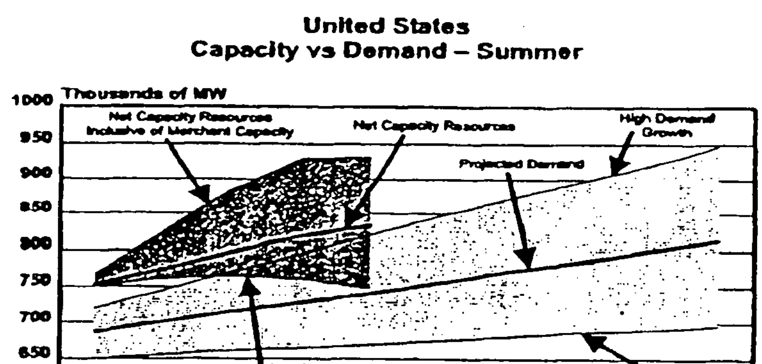


NERC is working with EPSA and the Energy Information Administration of the U.S. Department of Energy to improve its data collection methods to more accurately capture merchant plant generation additions for inclusion in its reliability analyses. In the future, NERC and EPSA will work to add a more detailed screening process to estimate the probability of new projects being completed by their projected in service dates.

Figure 5 depicts a period of only five years, since new capacity additions dwindle to zero after that time frame. The short time frame is a direct reflection of the shrinking planning horizon in today's more competitive electricity industry. It should be noted that substantial amounts of new merchant capacity have been announced above that which is shown in Figure 5 since this report was published and more announcements are being made almost every day.

Figure 6 overlays the projected capacity resources for the next five years on the projected load. As in Figure 5, there are three resource lines: one showing projected capacity resources without the inclusion of any announced merchant generation ("Net Capacity Resources Less Capacity Not Under Construction"), one indicating the best estimate of the Regions including some announced merchant plants ("Net Capacity Resources"), and finally, and one indicating the future resource situation if all announced merchant generation is constructed and brought on line as announced ("Net Capacity Resources Inclusive of Merchant Capacity"). Though it is highly unlikely the highest capacity resource line will materialize, it is important to note that projected resources exceed the high band load projections, resulting in adequate capacity margins even if the majority of the announced projects are not built.

Figure 6



3 - All EPSA generation values are as of June 15, 2000. Further amounts of new merchant capacity announcements have been made since that time.

Table 1: Demand and Capacity as Reported by the NERC Regions

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
		Summer – 2000			
ECAR	97,557	94,072	107,451	14.2	12.5
FRCC	37,728	34,832	40,645	16.7	14.3
MAAC	51,206	49,325	57,831	17.2	14.7
MAIN	51,271	47,165	55,984	18.7	15.8
MAPP - U.S.	32,899	30,606	35,373	15.6	13.5
MAPP - Canada	5,504	5,310	7,126	34.2	25.5
NPCC - U.S.	53,532	53,450	63,077	18.0	15.3
NPCC - Canada	44,569	43,383	68,191	57.2	36.4
SERC	151,065	142,725	160,780	12.7	11.2
SPP	39,383	37,807	43,111	14.0	12.3
Eastern Interconnection	564,714	538,675	639,569	18.7	15.8
WSCC - U.S.	116,440	112,177	136,274	21.5	17.7
WSCC - Canada	14,529	14,121	21,890	55.0	35.5
WSCC - Mexico	1,595	1,595	1,922	20.5	17.0
Western Interconnection	132,564	127,893	160,086	25.2	20.1
ERCOT Interconnection	54,817	51,697	65,423	26.6	21.0
United States	685,898	653,856	765,949	17.1	14.6
Canada	64,602	62,814	97,207	54.8	35.4
Mexico	1,595	1,595	1,922	20.5	17.0
NERC Total	752,095	718,265	865,078	20.4	17.0
		Summer – 2004			
ECAR	105,105	101,230	114,862	13.5	11.9
FRCC	41,004	38,164	46,652	22.2	18.2
MAAC	54,288	52,406	74,496	42.2	29.7
MAIN	54,697	50,567	62,530	23.7	19.1
MAPP - U.S.	34,040	31,488	35,399	12.4	11.0
MAPP - Canada	5,788	5,580	7,186	28.8	22.3
NPCC - U.S.	56,280	56,205	79,967	42.3	29.7
NPCC - Canada	47,336	46,132	74,887	62.3	38.4
SERC	166,505	158,441	179,345	13.2	11.7
SPP	42,715	41,056	46,966	14.4	12.6
Eastern Interconnection	607,758	581,269	722,290	24.3	19.5
WSCC - U.S.	126,477	122,151	157,805	29.2	22.6
WSCC - Canada	15,282	14,874	23,238	56.2	36.0
WSCC - Mexico	2,017	2,017	2,602	29.0	22.5
Western Interconnection	143,776	139,042	183,645	32.1	24.3
ERCOT Interconnection	61,129	57,932	71,978	24.2	19.5
U.S.	742,240	709,640	870,000	22.6	18.4
Canada	68,406	66,586	105,311	58.2	36.8
Mexico	2,017	2,017	2,602	29.0	22.5
NERC	812,663	778,243	977,913	25.7	20.4

Table 1: Demand and Capacity as Reported by the NERC Regions (continued)

Region	Total Internal Demand (MW)	Net Internal Demand (MW)	Planned Capacity Resources (MW)	Reserve Margins (% of Net Internal Demand)	Capacity Margins (% of Capacity Resources)
	Winter - 2000/01				
ECAR	86,455	83,331	108,339	30.0	23.1
FRCC	40,894	36,814	43,916	19.3	16.2
MAAC	43,139	42,307	60,815	43.7	30.4
MAIN	39,742	37,491	55,607	48.3	32.6
MAPP - U.S.	27,363	26,273	33,770	28.5	22.2
MAPP - Canada	6,713	6,535	8,216	25.7	20.5
NPCC - U.S.	45,294	45,170	65,355	44.7	30.9
NPCC - Canada	60,436	58,202	70,477	21.1	17.4
SERC	134,488	128,273	163,139	27.2	21.4
SPP	28,375	27,452	42,651	55.4	35.6
Eastern Interconnection	512,899	491,848	652,285	32.6	24.6
WSCC - U.S.	102,435	101,096	137,376	35.9	26.4
WSCC - Canada	17,779	17,371	22,035	26.8	21.2
WSCC - Mexico	1,120	1,120	1,680	50.0	33.3
Western Interconnection	121,334	119,587	161,091	34.7	25.8
ERCOT Interconnection	44,287	41,418	67,856	63.8	39.0
United States	592,472	569,625	778,824	36.7	26.9
Canada	84,928	82,108	100,728	22.7	18.5
Mexico	1,120	1,120	1,680	50.0	33.3
NERC Total	678,520	652,853	881,232	35.0	25.9
	Winter - 2004/05				
ECAR	92,429	89,193	113,364	27.1	21.3
FRCC	44,638	40,551	49,267	21.5	17.7
MAAC	45,767	44,933	79,309	76.5	43.3
MAIN	42,432	40,155	62,783	56.4	36.0
MAPP - U.S.	28,192	26,952	34,729	28.9	22.4
MAPP - Canada	7,039	6,831	8,216	20.3	16.9
NPCC - U.S.	47,506	47,369	82,193	73.5	42.4
NPCC - Canada	63,342	61,090	74,961	22.7	18.5
SERC	145,638	139,007	185,832	33.7	25.2
SPP	31,262	30,275	46,406	53.3	34.8
Eastern Interconnection	548,245	526,356	737,060	40.0	28.6
WSCC - U.S.	110,945	109,543	158,713	44.9	31.0
WSCC - Canada	18,872	18,464	23,107	25.1	20.1
WSCC - Mexico	1,420	1,420	2,610	83.8	45.6
Western Interconnection	131,237	129,427	184,430	42.5	29.8
ERCOT Interconnection	49,642	46,696	72,359	55.0	35.5
United States	638,451	614,674	884,955	44.0	30.5
Canada	89,253	86,385	106,284	23.0	18.7
Mexico	1,420	1,420	2,610	83.8	45.6
NERC Total	729,124	702,479	993,849	41.5	29.3

ASSESSMENT OF RELIABILITY

Interconnection Analysis

The Interconnection analysis examines the resource adequacy of the three Interconnections in North America. Trends are examined in projections of demand, capacity resources, and generating capacity needs.

The Interconnection margins and resources in this section are not simple additions of the constituent Regions in each Interconnection. Interconnection Capacity Margin and Net Interconnection Capacity Resources are terms specifically defined for this Interconnection analysis. These terms are used to quantify the generation within an Interconnection and the ability of the Interconnection to import resources from neighboring Interconnections. Net purchases and sales are not included in this calculation because all purchases and sales are limited to the resources within the Interconnection or by importing over the HVDC ties with the other Interconnections. A new 200 MW HVDC tie is planned to be in service in 2004 between SPP and WSCC. No other plans to increase the Interconnection tie capability were reported. The tie capability between ERCOT and the other Interconnections was assumed to be constant throughout the assessment period.

Although Interconnections exhibit satisfactory aggregate capacity margins, there may be isolated pockets within them that may experience adequacy problems from time to time, depending upon weather, generating unit availability, demand, and the ability of the transmission system to move power from generating sources to demand centers.

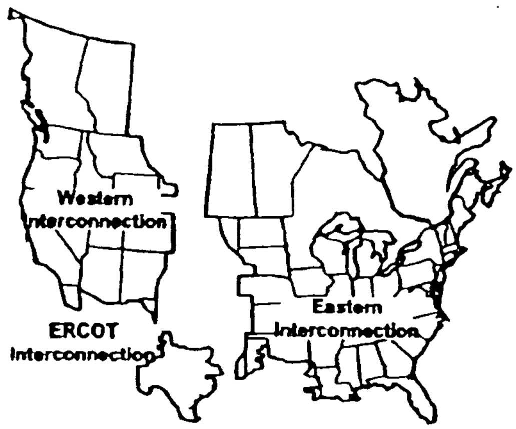
The Interconnections

The electric systems in the United States and Canada comprise three Interconnections:

Eastern Interconnection — the largest Interconnection covers an area from Québec and the Maritimes to Florida and the Gulf Coast in the East and from Saskatchewan to eastern New Mexico in the West. It has HVDC connections to the Western and ERCOT Interconnections.

Western Interconnection — the second largest Interconnection extends from Alberta and British Columbia in the North to Baja California Norté, Mexico, and Arizona and New Mexico in the South. It has several HVDC connections to the Eastern Interconnection.

ERCOT Interconnection — includes most of the electric systems in Texas with two HVDC connections to the Eastern Interconnection.



Interconnection Table Legend

The following legend is applicable to all of the Interconnection tables listed in the section.

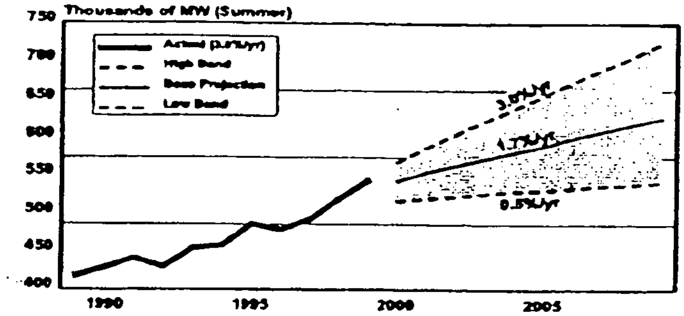
Internal Demand	Sum of Internal Demand plus Standby Demand (monthly coincident) for the Interconnection
Interruptible Demand & DCLM	Sum of Interruptible Demand and Direct Control Load Management (DCLM) for the Interconnection
Net Internal Demand	Interconnection Internal Demand less Interconnection Interruptible Demand and DCLM
Generating Capacity Reported by Regions	Sum of Projected Utility Generating Capacity plus Projected Merchant Generation Capacity for the Interconnection as reported by the NERC Regions
Interconnection Tie Capability	Import Capability of the Interconnection's HVDC ties to other Interconnections
Net Interconnection Capacity Resources	Interconnection Generating Capacity plus Interconnection Tie Capability
Interconnection Margin	Net Interconnection Capacity Resources less Interconnection Net Internal Demand
Interconnection Capacity Margin (%)	Interconnection Margin divided by Net Interconnection Capacity Resources, expressed as a percentage
Planned Capacity Additions Not Under Construction	Planned Capacity Resource Additions Not Under Construction as reported by the NERC Regions
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	Sum of Projected Utility Generating Capacity plus Projected Merchant Generation Capacity for the Interconnection as reported by the NERC Regions plus Interconnection Tie Capability less Planned Capacity Not Under Construction
Resulting Interconnection Margin	Net Interconnection Capacity Resources less Capacity Not Under Construction less Interconnection Net Internal Demand
Resulting Interconnection Capacity Margin (%)	Interconnection Margin divided by Net Interconnection Capacity Resources, expressed as a percentage
Announced New Merchant Capacity	Announced Merchant Capacity Additions not included in Net Capacity Resources reported by the NERC Regions
Net Capacity Resources Reported by Regions Plus Announced New Merchant Capacity	Sum of Projected Utility Generating Capacity plus Projected Merchant Generation Capacity for the Interconnection as reported by the NERC Regions plus Interconnection Tie Capability plus all other announced Merchant Generation Capacity
Resulting Interconnection Margin	Net Interconnection Capacity Resources less Interconnection Net Internal Demand
Resulting Interconnection Capacity Margin (%)	Interconnection Margin divided by Net Interconnection Capacity Resources, expressed as a percentage

Eastern Interconnection

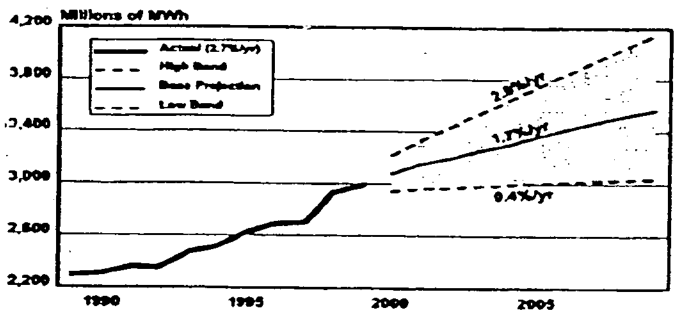
Demand in the Eastern Interconnection is projected to grow at 1.7% per year, which is well below the 3.0% growth experienced over the last ten years (Figure 7). Uncertainty in the demand forecast has slightly increased the range of the bandwidths from 1.2 to 2.4% last year to 0.5 to 3.0% this year.

Figure 7

Eastern Interconnection Peak Demand
2000-2009 Projection



Eastern Interconnection Net Energy for Load
2000-2009 Projection



Reported capacity margins for the Eastern Interconnection are above those projected last year for the first few years (Figure 8). Margins climb sharply in the near term and decline in the latter years of the analysis, as numerous merchant power plant projects come on line in the next five years. The number of announced merchant plants dwindles in the latter half of the assessment period, but as presented earlier in the discussion of Resource Adequacy (pp. 9–11) this does not necessarily mean that additional resources will not be added after 2004.

Figure 8

Capacity Margins
Eastern Interconnection – Summer

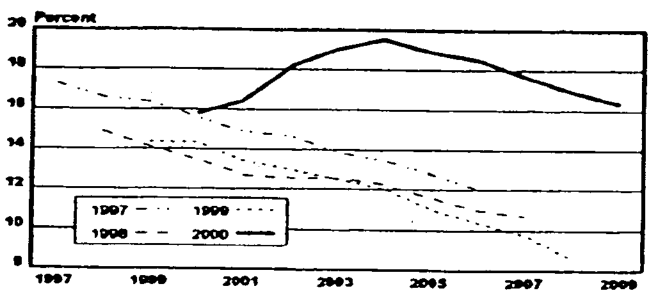


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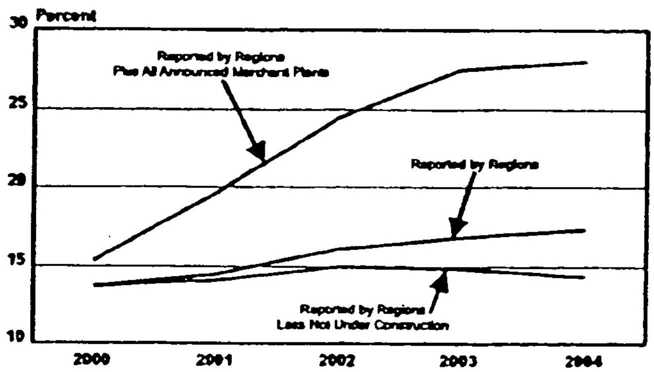
Figure 9 shows a range of possible capacity margins for the Eastern Interconnection, with the variable being the amount of assumed merchant generating capacity additions. The margins reported by the Regions in the Interconnection indicate an improvement from about 14% in 2000 to 17% by the end of 2004. These margins include a number of merchant projects for which the Regions have a high degree of confidence to make it to completion. However, EPSA is tracking a significant amount of announced merchant capacity in addition to that included by the Regions. If all of this capacity is included, margins will soar to 28% by 2004.

Figure 9

Eastern Interconnection
Capacity Margins – Summer



Not all announced merchant generation will be completed, but Figure 10 indicates that even if only a small portion of it is built and put in service, resources will exceed even the high band load projections for the next five years, resulting in adequate capacity margins. Unless new transmission facilities are constructed to alleviate congested transmission paths, the location of future generating resources will play an important role in their deliverability to end-users.

Figure 10

Eastern Interconnection
Capacity vs Demand – Summer

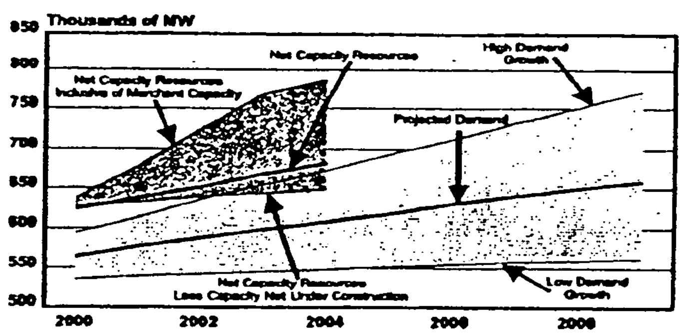


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Table 2 — Eastern Interconnection – Summer

	2000	2001	2002	2003	2004
Internal Demand	564,714	577,474	588,010	598,210	607,758
Interruptible Demand & DCLM	26,039	26,262	26,603	26,311	26,489
Net Internal Demand	538,675	551,212	561,407	571,899	581,269
Generating Capacity Reported by Regions	622,568	642,202	667,500	686,345	700,971
Interconnection Tie Capability	1,850	1,850	1,850	1,850	1,850
Net Interconnection Capacity Resources	624,418	644,052	669,350	688,195	702,821
Interconnection Margin	85,743	92,840	107,943	116,296	121,552
Interconnection Capacity Margin (%)	13.7	14.4	16.1	16.9	17.3
Planned Capacity Additions Not Under Construction	296	3,026	9,750	16,574	24,027
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	624,122	641,026	659,600	671,621	678,794
Resulting Interconnection Margin	85,447	89,814	98,193	99,722	97,525
Resulting Interconnection Capacity Margin (%)	13.7	14.0	14.9	14.8	14.4
Announced New Merchant Capacity	12,172	41,484	73,989	100,387	104,807
Net Capacity Resources Reported by Regions Plus Announced New Merchant Capacity	636,590	685,536	743,339	788,582	807,628
Resulting Interconnection Margin	97,915	134,324	181,932	216,683	226,359
Resulting Interconnection Capacity Margin (%)	15.4	19.6	24.5	27.5	28.0

Table 2 — Eastern Interconnection – Summer (continued)

	2005	2006	2007	2008	2009
Internal Demand	618,329	629,892	639,914	650,162	659,519
Interruptible Demand & DCLM	26,489	26,588	26,280	26,156	25,984
Net Internal Demand	591,840	603,304	613,634	624,006	633,535
Generating Capacity Reported by Regions	706,737	713,595	718,089	721,634	725,435
Interconnection Tie Capability	1,850	1,850	1,850	1,850	1,850
Net Interconnection Capacity Resources	708,587	715,445	719,939	723,484	727,285
Interconnection Margin	116,747	112,141	106,305	99,478	93,750
Interconnection Capacity Margin (%)	16.5	15.7	14.8	13.7	12.9
Planned Capacity Additions Not Under Construction	32,520	38,322	45,851	49,920	52,231
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	676,067	677,123	674,088	673,564	675,054
Resulting Interconnection Margin	84,227	73,819	60,454	49,558	41,519
Resulting Interconnection Capacity Margin (%)	12.5	10.9	9.0	7.4	6.2
Announced New Merchant Capacity	104,807	104,807	104,807	104,807	104,807
Net Capacity Resources Reported by Regions Plus Announced New Merchant Capacity	813,394	820,252	824,746	828,291	832,092
Resulting Interconnection Margin	221,554	216,948	211,112	204,285	198,557
Resulting Interconnection Capacity Margin (%)	27.2	26.4	25.6	24.7	23.9

ASSESSMENT OF RELIABILITY

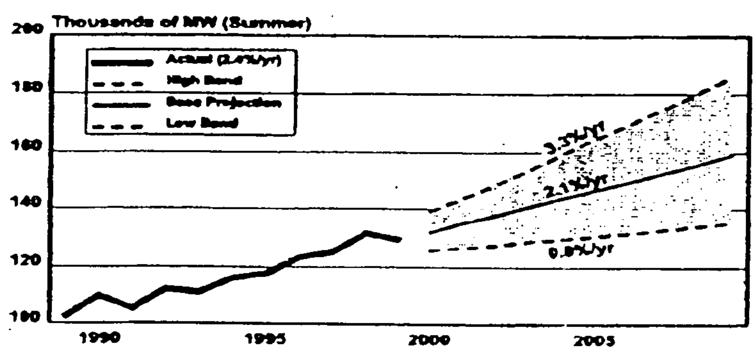
Western Interconnection

As in the other Interconnections, resource adequacy of the Western Interconnection will hinge largely on generation capacity additions made by merchant generation developers. Due to the nature of the Western Interconnection's bulk power system (large demand centers separated by long lines), the location of the generation additions will be key to their energy deliverability.

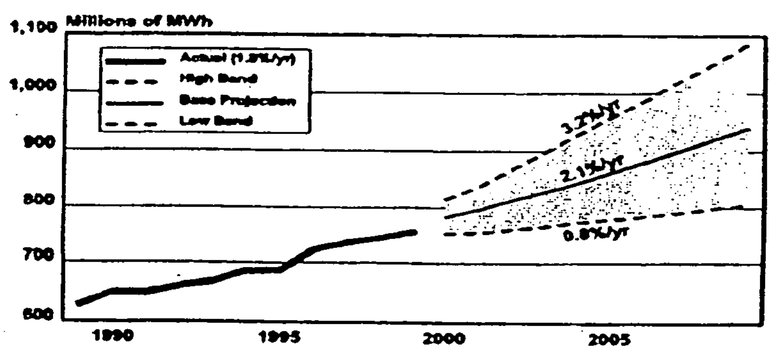
There have been a number of operating emergencies and alerts in the California area during summer 2000. Based upon the data contained in this assessment, it is expected that this condition will improve over the longer term (beyond the next five years). As indicated in the WSCC Regional section, uncertainties remain regarding portions of California due to the geography involved.

Figure 11

Western Interconnection Peak Demand
2000-2009 Projection



Western Interconnection Net Energy for Load
2000-2009 Projection



Demand in the Western Interconnection is projected to grow at 2.1% per year compared with the 2.4% average growth experienced in the West over the last ten years (Figure 11). The current growth rate projection is greater than the 1.6% growth rate projected last year.

The projected Western Interconnection capacity margin shows a significant increase (Figure 12) for 2000 through 2004, as new merchant capacity goes on line. The margin then declines just as sharply over the remainder of the assessment period, due to a severe drop off in reported capacity additions against the backdrop of continued demand growth.

Figure 12

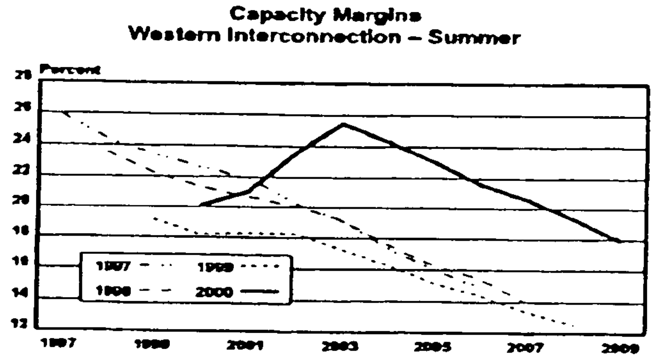


Figure 13 shows a range of possible capacity margins for the Western Interconnection, with the variable being the amount of assumed merchant generating capacity additions. The margin reported by the Region indicates an improvement from about 20% in 2000 to 25% by the end of 2004. These margins include a number of merchant projects for which the Region has a high degree of confidence to make it to completion. However, EPSA is tracking an additional 2,100 MW of announced merchant capacity in addition to that included by the Regions. If all of this capacity is included, margins will approach 26% by the end of 2004.

Figure 13

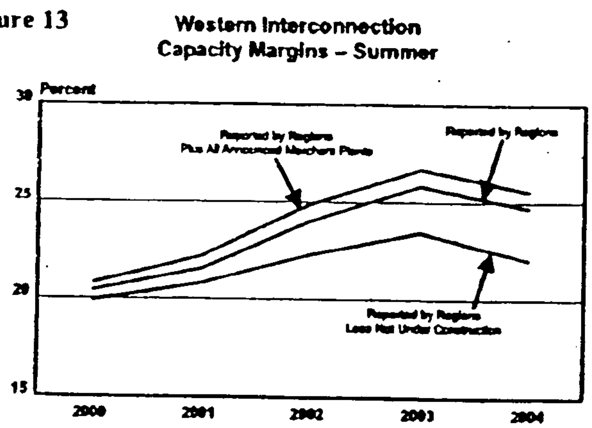


Figure 14

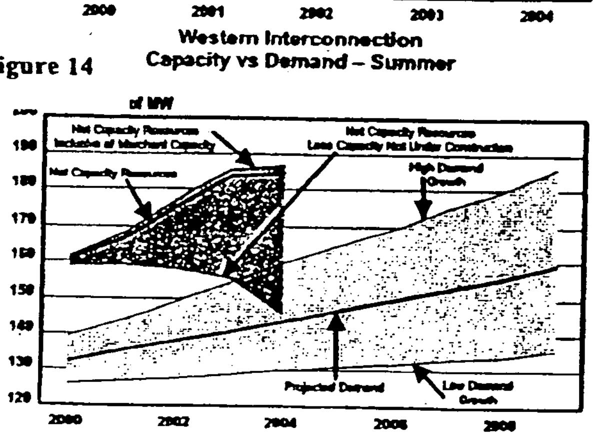


Figure 14 indicates that projected resources will exceed even the high band projections for the next five years, resulting in adequate capacity margins.

As can be seen in Figures 13 and 14, reporting entities in the Western Interconnection have captured and included the majority of announced new merchant generation being tracked by EPSA. Western Interconnection reporting entities are confident that a high percentage of this capacity will be built.

ASSESSMENT OF RELIABILITY

Table 3 — Western Interconnection – Summer

	2000	2001	2002	2003	2004
Internal Demand	132,564	135,366	138,077	140,891	143,776
Interruptible Demand & DCLM	4,671	4,708	4,707	4,731	4,734
Net Internal Demand	127,893	130,658	133,370	136,160	139,042
Generating Capacity Reported by Regions	159,570	165,400	174,396	182,530	183,599
Interconnection Tie Capability	1080	1080	1080	1080	1080
Net Interconnection Capacity Resources	160,650	166,480	175,476	183,610	184,679
Interconnection Margin	32,757	35,822	42,106	47,450	45,637
Interconnection Capacity Margin (%)	20.4	21.5	24.0	25.8	24.7
Planned Capacity Additions Not Under Construction	870	1,594	3,720	5,655	6,424
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	159,780	164,886	171,756	177,955	178,255
Resulting Interconnection Margin	31,887	34,228	38,386	41,795	39,213
Resulting Interconnection Capacity Margin (%)	20.0	20.8	22.3	23.5	22.0
Announced New Merchant Capacity	766	1,404	2,094	2,094	2,094
Net Capacity Resources Reported by Regions Plus Announced New Merchant Capacity	161,416	167,884	177,570	185,704	186,773
Resulting Interconnection Margin	33,523	37,226	44,200	49,544	47,731
Resulting Interconnection Capacity Margin (%)	20.8	22.2	24.9	26.7	25.6

Table 3 — Western Interconnection – Summer (continued)

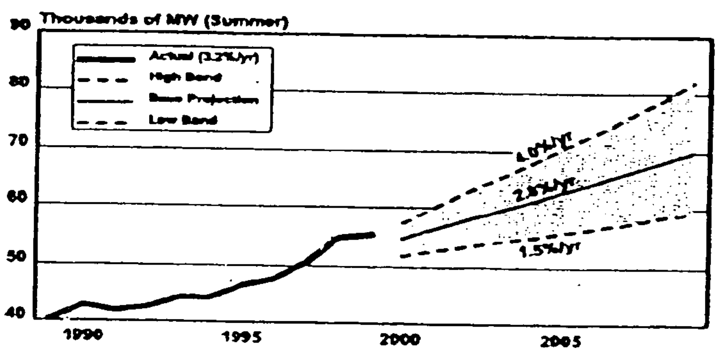
	2005	2006	2007	2008	2009
Internal Demand	146,795	149,803	152,757	155,846	159,186
Interruptible Demand & DCLM	4,737	4,742	4,745	4,746	4,748
Net Internal Demand	142,058	145,061	148,012	151,100	154,438
Generating Capacity Reported by Regions	184,504	184,907	186,354	187,224	187,936
Interconnection Tie Capability	1080	1080	1080	1080	1080
Net Interconnection Capacity Resources	185,584	185,987	187,434	188,304	189,016
Interconnection Margin	43,526	40,926	39,422	37,204	34,578
Interconnection Capacity Margin (%)	23.5	22.0	21.0	19.8	18.3
Planned Capacity Additions Not Under Construction	7,367	8,127	9,025	9,025	9,025
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	178,217	177,860	178,409	179,279	179,991
Resulting Interconnection Margin	36,159	32,799	30,397	28,179	25,553
Resulting Interconnection Capacity Margin (%)	20.3	18.4	17.0	15.7	14.2
Announced New Merchant Capacity	2,094	2,094	2,094	2,094	2,094
Net Capacity Resources Reported by Regions Plus Announced New Merchant Capacity	187,678	188,081	189,528	190,398	191,110
Resulting Interconnection Margin	45,620	43,020	41,516	39,298	36,672
Resulting Interconnection Capacity Margin (%)	24.3	22.9	21.9	20.6	19.2

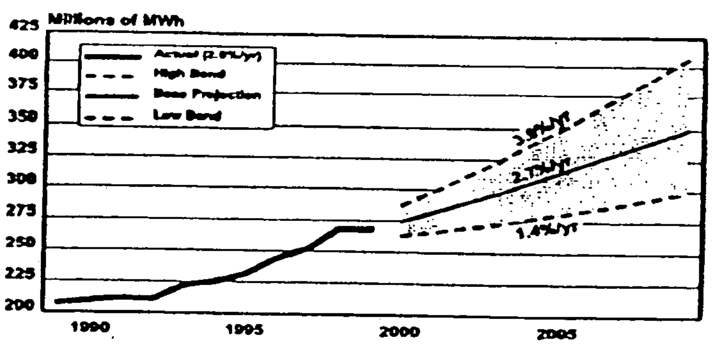
ERCOT Interconnection

Despite high demand growth experienced over the past few years due to a robust economy and higher-than- expected temperatures, planned and announced capacity additions are expected to provide adequate capacity resources in ERCOT for the near term.

Demand in the ERCOT Interconnection is projected to grow at 2.8% per year, compared with the 3.2% average growth experienced in ERCOT over the last ten years (Figure 15). The high and low bandwidths assume normal long-term weather patterns. Actual peak load growth in ERCOT has been exceptionally high during the past several years primarily due to record-breaking temperatures. However, the demand forecast for ERCOT of 2.8% is very conservative and assumes normal temperatures and some tapering off of the economy and population growth in the state.

Figure 15





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The reported ERCOT Interconnection's capacity margin (Figure 16) exhibits the same phenomenon as the other interconnections: a sharp increase in the near term as merchant plants come on line followed by a commensurate decrease in later periods due to a lack of proposed new facility additions.

Figure 16

Capacity Margins
ERCOT – Summer

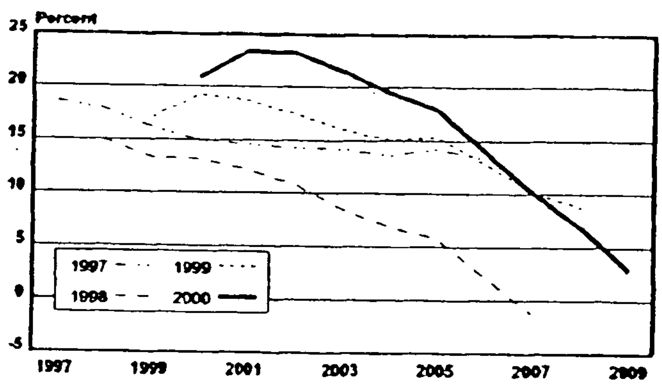
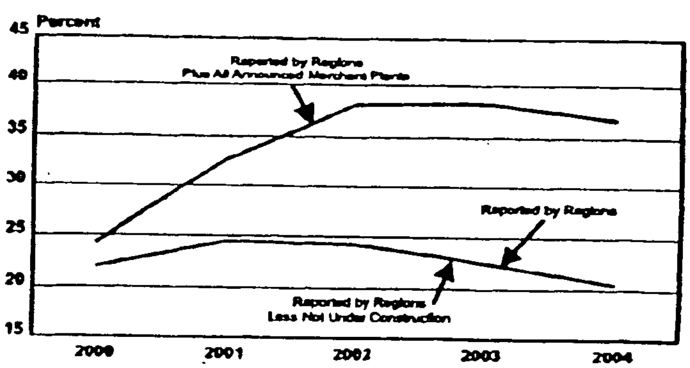


Figure 17 shows a range of possible capacity margins for ERCOT, with the variable being the amount of assumed merchant generating capacity additions. The margin reported by the Region indicates a slight decrease from about 22% in 2000 to 20% by the end of 2004. These margins include a number of merchant projects for which the Region has a high degree of confidence to make it to completion. It is important to note that in ERCOT, unlike the other Interconnections, the capacity margin adjusted for "projects not under construction" matches that representing the best estimate of the Region and the two lines in Figure 16 overlay each other. In other words, the projected margins reported by ERCOT include only those capacity additions that are currently under construction. EPSA is tracking a significant amount of announced merchant capacity in addition to that included by the Regions. If all of this capacity is included, margins will exceed 36% by the end of 2004.

Figure 17

ERCOT Interconnection
Capacity Margins – Summer



ASSESSMENT OF RELIABILITY

Not all announced merchant generation will be completed, but Figure 18 indicates that even if only a small portion of it is built and put in service, resources will exceed even the high band load projections for the next five years, resulting in adequate capacity margins.

Figure 18

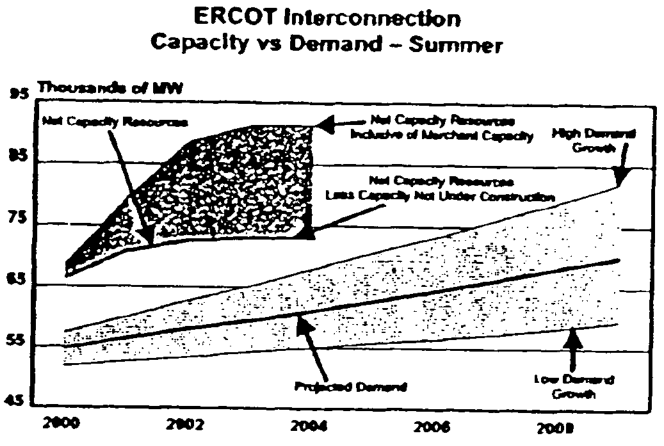


Table 4 — ERCOT Interconnection – Summer

	2000	2001	2002	2003	2004
Internal Demand	54,817	56,501	58,079	59,637	61,129
Interruptible Demand & DCLM	3,120	3,087	3,127	3,161	3,197
Net Internal Demand	51,697	53,414	54,952	56,476	57,932
Generating Capacity Reported by Regions	65,439	69,839	71,715	72,090	72,088
Interconnection Tie Capability	856	856	856	856	856
Net Interconnection Capacity Resources	66,295	70,695	72,571	72,946	72,944
Interconnection Margin	14,598	17,281	17,619	16,470	15,012
Interconnection Capacity Margin (%)	22.0	24.4	24.3	22.6	20.6
Planned Capacity Additions Not Under Construction	0	0	0	0	0
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	66,295	70,695	72,571	72,946	72,944
Resulting Interconnection Margin	14,598	17,281	17,619	16,470	15,012
Resulting Interconnection Capacity Margin (%)	22.0	24.4	24.3	22.6	20.6
Announced New Merchant Capacity	2,076	8,628	16,068	18,468	18,468
Net Capacity Resources Reported by Regions Plus Announced New Merchant Capacity	68,371	79,323	88,639	91,414	91,412
Resulting Interconnection Margin	16,674	25,909	33,687	34,938	33,480
Resulting Interconnection Capacity Margin (%)	24.4	32.7	38.0	38.2	36.6

Table 4 — ERCOT Interconnection – Summer (continued)

	2005	2006	2007	2008	2009
Internal Demand	62,772	64,496	66,268	68,089	69,959
Interruptible Demand & DCLM	3,234	3,257	3,281	3,305	3,329
Net Internal Demand	59,538	61,239	62,987	64,784	66,630
Generating Capacity Reported by Regions	72,588	71,273	70,174	69,614	68,670
Interconnection Tie Capability	856	856	856	856	856
Net Interconnection Capacity Resources	73,444	72,129	71,030	70,470	69,526
Interconnection Margin	13,906	10,890	8,043	5,686	2,896
Interconnection Capacity Margin (%)	18.9	15.1	11.3	8.1	4.2
Planned Capacity Additions Not Under Construction	500	500	500	500	500
Net Capacity Resources Less Capacity Not Under Construction as Reported by Regions	72,944	71,629	70,530	69,970	69,026
Resulting Interconnection Margin	13,406	10,390	7,543	5,186	2,396
Resulting Interconnection Capacity Margin (%)	18.4	14.5	10.7	7.4	3.5
Announced New Merchant Capacity	18,468	18,468	18,468	18,468	18,468
Net Capacity Resources Reported by Regions Plus Announced New Merchant Capacity	91,912	90,597	89,498	88,938	87,994
Resulting Interconnection Margin	32,374	29,358	26,511	24,154	21,364
Resulting Interconnection Capacity Margin (%)	35.2	32.4	29.6	27.2	24.3

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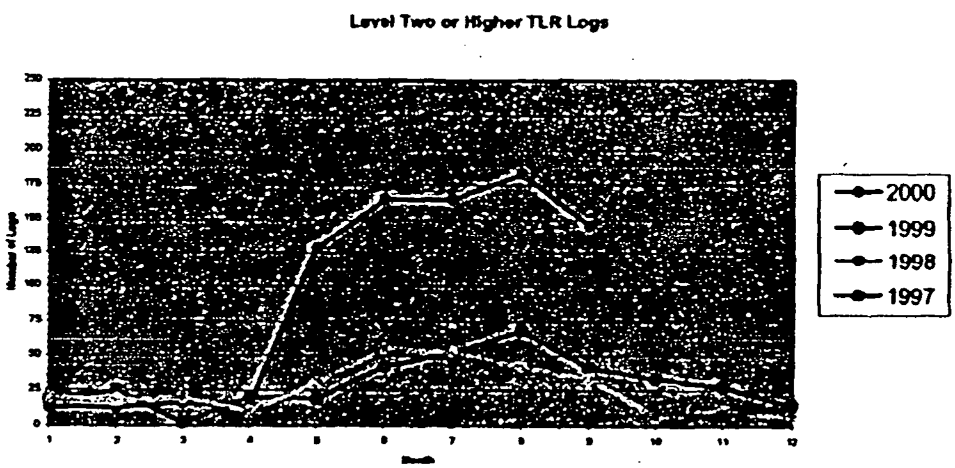
Transmission Adequacy and Security Assessment

The transmission system of North America is expected to perform reliably at least in the near term. Procedures and processes to mitigate potential reliability impacts appear to be working effectively for now. However, the loadings on the transmission system are increasing as customer demand for electricity increases and as the system experiences new loading patterns resulting from increased power transfers.

The transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience. New flow patterns result in an increasing number of facilities being identified as limits to transfers, and transmission loading relief (TLR) procedures have been required in areas not previously subject to overloads to maintain the transmission facilities within operating limits. NERC TLR is called by security coordinators to curtail transactions that cause transmission facility overloads or violations of operational security limits. Transmission facility overloads or operation at levels near security limits do not necessarily translate into an unreliable or unsecure transmission system; this may instead be an indication that the transmission system is fully utilized and will not support any further economic transfers of energy. There are several steps or classifications of NERC TLR, ranging from Level 0 to 6.[4] Curtailments of transactions do not occur until Level 3 (non-firm) and Level 5 (firm).

Figure 19 depicts the number of TLR events for the past four years as reported to NERC. As can be seen, the number has steadily grown as power transfers have increased and the transmission system has become more fully subscribed. The reader should note that the Figure portrays only the TLR Level 2 or higher events and not each individual TLR, as an event may have multiple TLR levels. Transaction curtailments occur at TLR Level 3 and above, so the Figure includes events that did not result in transaction curtailments. Further, curtailment of firm demand occurs at TLR Level 5, so the Figure should not be interpreted as indicating events resulting in firm demand curtailments, as these events are very rare. (The Figure has been included to illustrate the overall trend.)

Figure 19



4 - For more information regarding NERC TLR and its levels, please visit http://tlr.nerc.com.

Maintaining System Reactive Capability

A significant challenge to the transmission providers will be to maintain adequate levels of reactive support for the transmission system in the new open-market era. Unlike real power (MW), the reactive component of power (Mvar) cannot be easily transmitted over distances and must be supplied locally. Without adequate reactive support, parts of the system can be susceptible to potential voltage collapse or instability. Sources of reactive power include generators, synchronous condensers, transmission lines, capacitors, and very specialized reactive support devices generally known as static var compensators (SVCs). Demand for reactive power is driven by the size and type of demand, power transactions across the transmission system, and the loading of transmission facilities.

Many utilities made concerted efforts to improve reactive support as demand grew by adding shunt capacitors on their distribution and subtransmission systems. However, there may have been a falloff in maintaining such distribution reactive improvement programs in recent years. Reactive support programs must be ongoing as demand on the distribution system continues to grow, and a chief component of that growth, air conditioning, particularly requires it. Most air conditioner demand is motor load, requiring significant reactive power. Because of its interaction with the transmission system, reactive support is one area that distribution companies cannot ignore if reliability is to be maintained on the bulk transmission system.

The physics of transferring power across a transmission line causes it to consume reactive power, with increased transfers resulting in increased voltage drop across the line. When heavy power transfers occur across a transmission system interface and transmission lines are heavily loaded, voltage in the area of the interface can become depressed if sufficient reactive supplies are not available to the system.

When transfers of power follow a consistent directional pattern, it is relatively easy to plan and justify cost for the required reactive support for the transfers. Significant reactive support was added on the bulk system to enable higher transfers from ECAR to MAAC and the VACAR Subregion of SERC in the early 1990s. However, under open access, transactions are being done in large numbers across long distances, and often in directions that were not anticipated when the transmission system was planned and built. Also, the direction and amount of transfers has become much more volatile, changing daily, and sometimes hourly. Consequently, planning reactive support enhancements for improving transfer capability is now extremely difficult.

There is currently no incentive to increase the levels of reactive support on the bulk power systems. In fact, there are disincentives, because generators are paid to produce real power, not reactive power. There is a tradeoff between producing real and reactive power because reactive power generation decreases as the real output increases. A recent spate of nuclear unit upgrades effectively lowered the units' reactive power output capabilities.

In the long term, transmission providers need to reevaluate their systems in light of open access, including planning for necessary reactive support. Business is increasing on the transmission system, but very little is being done to increase the load serving and transfer capability of the bulk transmission system. Most of the transmission projects planned over the next ten years are intended to reinforce parts of the system to alleviate local problems.

Table 5 — Planned Transmission

	Transmission Circuit Miles 230 kV and Above			
	2000 Existing	2000-2004 Additions	2005-2009 Additions	2009 Total Installed
ECAR	15,843	301	155	16,299
FRCC	6,618	203	213	7,034
MAAC	7,049	58	95	7,202
MAIN	5,699	303	–	6,002
MAPP – U.S.	15,236	494	49	15,779
MAPP – Canada	5,846	219	282	6,347
NPCC – U.S.	6,456	228	5	6,689
NPCC – Canada	28,806	335	13	29,154
SERC	30,541	1,401	696	32,638
SPP	6,499	428	305	7,232
Eastern Interconnection	128,593	3,970	1,813	134,376
WSCC – U.S.	56,836	1,335	482	58,653
WSCC – Canada	10,714	(22)	46	10,738
WSCC – Mexico	431	–	–	431
Western Interconnection	67,981	1,313	528	69,822
ERCOT Interconnection	7,033	710	111	7,854
United States	157,810	5,461	2,111	165,382
Canada	45,366	532	341	46,239
Mexico	431	–	–	431
NERC Total	203,607	3,993	2,452	212,052

Only 8,445 miles of transmission facility additions (230 kV and above) are planned throughout North America over the next ten years. This represents only a 4.2% increase in total installed circuit miles and most of these additions are intended to address local transmission concerns and will not have a significant impact on long distance power transfers. Newly announced transmission projects have resulted in an increase of 1,467 circuit miles over last year's projection.

Four significant EHV transmission projects have been proposed in ERCOT through the ISOs planning process. Those projects are funded by a unique Texas-mandated cost-sharing formula for transmission projects. However, appropriate conditions do not exist in all Regions to encourage transmission system additions and reinforcements to support the needs of the competitive market. New Regional planning entities and approval processes must also be developed to deal with the need for new transmission lines for an open market.

More information regarding the challenges of siting and building new transmission facilities can be found in the next section of this report.

Market Transition

The North American electric industry has built an impressive record of reliable electric service. Traditional vertically integrated utilities, with an obligation to supply electric service and regulated as natural monopolies, provided an effective structure for electricity supply. However, concern over the ability of monopoly service to provide incentives for cost minimization and innovative products and services drew legislators' and regulators' attention to the economic advantages of competitive markets for generation.

As a result, the electricity industry in North America is in the midst of a major transition. Bundled monopoly service is being replaced by a competitive marketplace for generation at the wholesale level, and, where states and provinces have adopted restructuring mandates, competitive retail markets are developing as well. While transmission and distribution services continue to be provided by utilities, the Energy Policy Act of 1992 expanded the authorization for nonutility companies to build and operate power plants that were established previously by the Public Utility Regulatory Policies Act of 1978. The Federal Energy Regulatory Commission's (FERC) issuance of Orders 888 and 889 in 1996 allowed these competitive suppliers open access on a nondiscriminatory basis to the bulk power transmission system. In addition to open access, FERC Order 888 prompted utilities to establish independent system operators (ISOs) to operate the power grids. Most recently, in Order 2000, FERC has urged transmission owners to join regional transmission organizations (RTOs) to improve the engineering and economic efficiency of the transmission grid. These developments have given rise to new opportunities and challenges, as the structure and function of the industry continues to evolve toward full competition.

To obtain the benefits sought through competitive markets, many important and challenging implementation issues must be addressed, including Interconnection policies, market power, stranded cost recovery, and ongoing market interventions. The rapid changes bring many challenges to all of the market participants as they react to economic pressures while simultaneously maintaining the reliability of the power system.

High Market Prices and the Integrity of Interchange

An unexpected threat to reliability materialized in late July 1999 when system frequency on the Eastern Interconnection dipped to one of its lowest levels in history (59.93 Hertz). This occurrence was later shown to be due to significant under-generation by at least two control areas in the central United States during times of very high energy prices. Control areas with a significant market exposure will effectively take energy from the rest of the Interconnection when prices are high and replace it when prices are lower if they do not purchase the energy to cover their obligation. NERC operating policies require that systems short of power shed load to protect the integrity of the grid in cases where no purchase power is available, but the experience of July 1999 shows that abuses driven by spikes in energy prices can alter behavior, leading to a significant threat to reliability. NERC is dealing with this issue by clarifying the roles of the various players in the control area function and encouraging the pricing of inadvertent energy exchanges at prevailing market prices. Additionally, at least one Region has taken steps to address this problem.

Incentives to Construct Transmission

The transmission grid was originally designed to transmit the output of the generation units over fairly short distances to the local load centers. With the recent industry restructuring and the development of regional wholesale markets, the utilization of the transmission grid has drastically changed to try to accommodate a large volume of energy transactions over very long distances. This trend towards a dependency on the transmission grid to facilitate not only economic but also emergency energy transactions is expected to continue into the future.

A robust, reliable transmission system is needed to develop a competitive market and to achieve its full benefits. There is a heightened interest in this area by regulators and legislators at the state, provincial, and federal levels during this transition. The challenge before them is to enable market participants to build transmission and generation projects in optimal locations (from both a transmission and generation perspective) in order to obtain the maximum benefits of competition while maintaining reliability. This will require both financial incentives and aid in dealing with siting issues. The recent FERC decision to allow an alternative methodology for determining the allowed return on transmission assets and FERC Order 2000 may stimulate additional investment in transmission.

During the 1960s and early 1970s when technological improvements enabled (and encouraged) the construction of extra-high voltage transmission lines, the justification for constructing the lines was the reliability benefit everyone would realize due to reserve sharing. By tying Regions together, any individual Region would be less vulnerable to blackouts and system collapse because it would be able to access the reserves of its neighbors. Although the new lines certainly facilitated inter-utility economy transactions, the volume of such economy transactions was relatively low and the central purpose of the lines remained to enhance reliability. To the extent economy transactions occurred, all customers benefited. As such, the use of eminent domain (the legal basis by which land may be acquired for public use) to acquire the rights-of-way these lines used was acceptable.

The changing electric market may be breaking down the social compact behind the principle of eminent domain, affecting new transmission line construction and may change the way in which reliability is maintained. Public opposition to the construction of transmission facilities and regulatory uncertainties for cost recovery on transmission investments limit new transmission facility additions. The gap between the transmission expansion need and the proposed construction of transmission is widening. To support the reliability of the bulk power system, proper incentives must be developed to encourage transmission construction.

One way to relieve transmission congestion is to build new transmission lines. This solution to the congestion problem requires new interregional transmission lines to accommodate what principally will be transactions between geographically separate areas. The segments of the population impacted by the new transmission line construction will not be the same segments that are benefiting from the profits the new lines create. This disparity will increase the legitimacy of the political opposition to new transmission line construction. The fragmentation of the industry into segments not easily identifiable with the familiar local utility may make matters worse. The step to limiting the power of eminent domain (to, say, lines with a demonstrable public, rather than private, benefit) may be an easy one for legislators.

Assuming permission to build transmission facilities can be obtained, who will fund and promote the development of new transmission projects? Varying approaches are currently being applied. ERCOT is sharing the cost of the transmission system equally among all loads. Alberta issued a Request for Proposals for generation projects that would decrease the need for additional transmission lines and construction is now underway on a number of projects. Additional incentives are to be paid to the generation constructors based on the avoided cost of the transmission projects that would have been required. There is also the possibility of Independent Transmission Projects.

Other approaches to address transmission system limitations and congestion include the construction of new generation in demand centers, the implementation of advanced transmission technologies, or economic incentives for customers to voluntarily reduce their loads. Those interested in system reliability may have to consider ways to encourage such local solutions (which may themselves have construction and sighting problems similar to those of transmission construction) to avoid being forced to depend on new transmission construction as the only solution for deteriorating system reliability.

Market Price

In contrast to the stable energy prices of the traditional regulated utility with an obligation to serve the demand of its native load, the provision of electric energy in an open market environment will necessarily reflect the potentially volatile prices of the commercial market. As price spikes have indicated in the past, the market price in the short term may become excessively high. These high prices may result in situations where providers, unsure of recovery of costs, curtail service to customers, or consumers will no longer be able to afford the service. In the absence of an obligation to serve, high market prices may jeopardize continuity of electric service in the sense that unaffordable prices may discourage providers from purchasing and delivering energy to consumers.

Consumer Response to Pricing

A fundamental component of electricity markets, and one that has been conspicuously absent in the regulated utility environment is consumer demand price response. At present, most electricity customers have no exposure to real-time energy prices; they are served under fixed-price tariffs. This fixed-price arrangement worked fine when market prices were less volatile than they are today. Now it has become very risky for suppliers who may not be prepared to serve at any price. To mitigate this financial risk, create an efficient and effective electric energy market, and improve the reliability of electric supply, some or all electric customers will have to be exposed to market prices and suppliers will have to develop effective financial hedges to allow them to provide fixed-price contracts without assuming undo risk.

Some load serving entities have experimented with this trade-off by designing interruptible load tariffs in which customers offer to have their service curtailed if the utility supplier runs short of capacity. Many of these tariffs also specify that such interruptible customers will pay market energy prices when the supplier's price exceeds a certain threshold. With the recent experiences with summer price spikes, some utilities have expanded these interruptible programs by allowing customers to bid their firm load into the market. This allows utilities to mitigate their price risk by paying their customers to curtail service to firm load.

These experiences with market pricing have been instructive. Offered the possibility of high energy buy-back prices, many electric customers have found it more profitable to shut down than to continue operations. However, the price at which customers are willing to discontinue their service is usually significantly greater than traditional electricity prices. Because this value is still much lower than the price spikes seen the last two summers, it is nevertheless in the utility's interest as well as the customer's to exploit the benefits of customer demand curtailment programs.

Ultimately, if every electric load saw instantaneous real-time pricing, demand would be balanced with supply and customers would be willing to discontinue their service or reduce their consumption as prices rose. In such a perfect world, the feedback mechanism would serve to reduce consumption and promote adequacy.

In California this summer many retail customers were exposed to market prices and saw a doubling (or more) of their electricity bills. The early experience in California exposes the difficulty of developing a market that will ensure adequacy; prices are volatile in evolving electricity markets and may result in prices that are much higher than those expected by consumers. The adequacy problem will not be solved in the near term by merely converting it into a price problem.

Load Forecasting

Traditionally, load forecasts have been crucial in planning to meet the needs of vertically integrated electric utilities. A credible load forecast is necessary in the planning and operation of transmission and generation facilities, revenue and expense forecasts, and in developing forecasts of financial requirements. Regional transmission organizations (RTOs) may be responsible for reliability in the future and, in a market environment, demand forecasts will continue to be crucial for the RTOs. Load serving entities, providers of last resort, transmission providers, transmission planners, system operators, and those attempting to assess reliability will also continue to have a need for accurate load forecasts. In those states in which there continues to be a "minimum" reserve requirement, for example, there must be a forecast of demand to balance against the forecast of supply to compare the resulting capacity reserves with the minimum requirement. This forecast should include the amount of load that is expected under contract and the type of service such as interruptible load. Several states such as Texas, Florida, and New York have a minimum capacity reserve that must be maintained. In addition, the state regulatory bodies in some cases use reserves in their evaluation of the performance of electric utilities in their jurisdiction. Utilities must show that prudent actions were taken to ensure adequate resources were being developed to meet firm contracts. There have been recent lawsuits because a utility was unable to supply firm load as contracted.

The role of load forecasts in generation planning will change as the electric industry evolves towards full competition. With the increasing dependence on merchant generation, capacity expansion will not necessarily be driven by the load forecast, but will be more influenced by market price signals. Even though market prices will be key to the developer's decisions regarding locating merchant capacity, there will continue to be a need to forecast trends and conditions within Regions for the developer to include in the decision process. In addition, it will become important to forecast the location of both the loads and supply so that those components of reliability are balanced. Transmission congestion prices may be useful in helping to balance these concerns.

In a market environment, load forecasting will become a more challenging function for the industry. NERC's Load Forecasting Working Group may have to address these forecasting issues to ensure forecasts are totally representative of the needs of the Regions. Who will ultimately be responsible for the quality of the load forecast given that multiple parties are involved in the development of the forecast of demand, supply, and resulting market signals? How will the load forecast be communicated, and how can it be challenged?

In the future, factors such as price elasticity of demand and development of demand-side resources as a response to market signals may have more marked effects on the customer demand for electricity. These factors are controlled by multiple parties and will interplay with market conditions. Transmission providers who have historical load information on which to base future demand may not be able to predict firm requirements since there are interruptible contracts, which are exercised dependent on the market price of electricity. There could be multiple levels of reliability available to customers depending upon how much they are willing to pay and this will increase the complexity of the load forecasting process.

Another difficulty in forecasting comes from the increase in the saturation of distributed generation. Even with significant economic growth, there are some scenarios in which customer-owned generators can either decrease contract use or result in a net input into the transmission grid. This could create or increase transmission congestion in particular areas of the transmission system. Currently, state and national legislation is being considered for certain renewable technologies that would result in net energy metering so that a customer who used energy during on-peak periods could pay it back during low-cost off-peak periods and net its use to zero. However, if large quantities of energy are net metered, it is unclear who will pay for transmission and distribution facilities.

In order to provide a reliable forecast, the industry needs to maintain or develop an information system that will accurately reflect the various market conditions. The RTOs or transmission providers can develop the load forecast, but this will require the cooperation of all other involved parties. In addition, it may become important to consider the consistency of load forecast information, such as the number of historical weather years or trends in climate, that are considered in developing the forecast.

Firm Load: Firm Generation Obligation

Electricity supply to all customers can only be assured if all electricity retailers have contracted with sufficient generation and transmission capability to ensure that customer demand can be served at all times. Without market incentives, information, enforcement authority to penalize deficit load serving entities, or the technical capability to select discrete customers for curtailment, retailers will have to implement load shedding when the real-time generation market undergoes a supply shortage. Using this approach, system security can be maintained, but not all customers are treated equitably.

However, if the industry has the information pertaining to deficient areas and enforcement authority, retailers will be able to differentiate themselves by their load curtailment performance, and those that spend more money to acquire wider reserve margins will be able to offer more "reliable" service. Retailers who are able to aggregate complementary loads (with non-coincident peaks) may be able to offer lower rates. Special rates could also be provided to customers willing to help provide load relief during supply shortages, much like the interruptible contracts presently held by industrial customers, but perhaps spread over a wider customer spectrum. "Time of Day" rates could also be offered to customers willing to pay for the extra costs of metering.

Regulatory and Legislative

U.S. Federal Legislation

Prospects for action on federal restructuring legislation will improve with the next Congress, although the timing for that action, and the scope of issues to be addressed, are still unclear. At least four restructuring bills were introduced in 2000 that have included a reliability title based on NERC's consensus legislative language, which provides for the establishment of an independent self-regulating reliability organization to set and enforce compliance with mandatory reliability standards for the bulk power system, with FERC oversight in the United States.

Among the other issues being considered for inclusion in restructuring legislation are: private-use restrictions on facilities financed with tax-exempt debt; revisions to the Public Utility Holding Company Act and the Public Utilities Regulatory Policy Act; portfolio standards for renewable energy; a federal matching fund to encourage public-benefit programs at the state level; and possible new environmental requirements.

Legislation was introduced in both the House and Senate to resolve the private use restrictions on public power and other restructuring-related tax issues faced by investor-owned utilities. The Electric Power Industry Tax Modernization Act reflects the recent agreement between the American Public Power Association, the Edison Electric Institute, and the Large Public Power Council on industry-wide tax issues that they say need to be updated to accommodate the emerging competitive electricity market. This legislation is needed to support participant's filing intentions to join regional transmission organizations and the expiration of IRS's temporary regulation on private use in January 2001.

FERC

In December 1999, FERC issued a final rule encouraging the formation of Regional Transmission Organizations (RTOs). The rule established minimum characteristics and functions that a transmission entity must satisfy to be considered an RTO. The Commission describes four minimum characteristics of an RTO: independence, appropriate scope and regional configuration, sufficient operational authority, and responsibility for short-term reliability. The Commission describes eight minimum functions that an RTO must perform: tariff administration and design, congestion management, management of parallel path flow, provision of ancillary services, maintain OASIS and calculate Total Transfer Capability and Available Transfer Capability, market monitoring, planning and expansion, and interregional coordination.

The rule required each jurisdictional utility to make filings with the Commission either demonstrating its participation in an RTO that satisfied the minimum requirements, describing its efforts to form an acceptable RTO, or explaining its reasons for not doing so, and its future plans. FERC expects that RTOs meeting the minimum characteristics and functions would begin operating the transmission facilities no later than December 15, 2001.

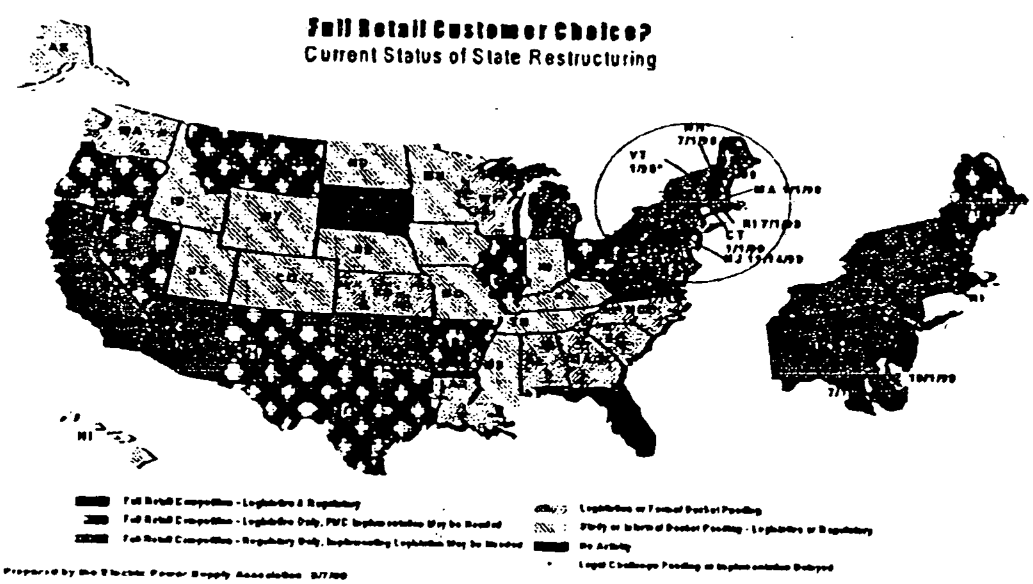
On February 25, 2000, FERC issued Order No. 2000-A, reaffirming its December 1999 RTO rule. The rehearing order retained the voluntary approach to RTO formation, as well as the deadlines set out in the final rule for filings due in October 2000 and January 2001. It also clarified the definition of "market participant," concluding that those entities offering transmission services should not be included in the definition of market participant, since some might argue that a pure transmission company that was an RTO might meet that definition. Independent governance of a "pure Transco" will be addressed on a case-by-case basis. The order also clarified the respective rights of the RTO to file its rates with FERC, and of the transmission owner to file to recover its revenue requirement. In addition, Order No. 2000-A includes the ownership audit requirements in the regulatory text and expressly includes cooperatives among the public power entities that must be included in the RTO formation process.

State Issues

Twenty-five states and the District of Columbia have adopted restructuring legislation or regulatory orders and almost all others are contemplating it at some level. However, the recent experience in San Diego with significant retail price increases has dampened or postponed state interest in advancing retail competition. Several states and local government organizations are urging Congress to let states handle most of the restructuring issues. Among the states that have embraced retail competition, many prefer that any federal restructuring legislation allow states to take the lead on many implementation issues. Congress and the Administration indicated willingness to grandfather existing state restructuring plans.

In the wake of FERC Order 888 and Order 2000, many state commissions are concerned about the ambiguity of jurisdiction over retail sales of electricity, particularly in states that have restructured for retail competition in generation services. State regulators have expressed a desire to participate in Regional Transmission Organizations, with particular interests in reliability, market monitoring, pricing, congestion management, planning, and interregional coordination. While each state has a somewhat different regulatory authority and structure, all states will retain an ongoing interest and concern over reliability issues in electric service.

The map below shows the current status (August 2000) of state restructuring initiatives.



Provincial Issues

In Canada, reliability management has been the primary responsibility of the utilities, which developed their own standards and participated in developing voluntary reliability standards through NERC. Although NERC's Standards are recognized by the utilities as the industry standard in Canada, each provincial government must grant approval of electrical entities to participate in NAERO.

The National Energy Board's jurisdiction related to reliability is over the construction and operation of international power lines and electricity exports. In many cases, provincial regulators have broad jurisdiction to ensure that the electricity system is operated in a safe and reliable manner, to approve applications for new generation or transmission facilities, to approve rates, or to impose operating restrictions on transmission facilities. In all provinces, except Saskatchewan, provincial regulators oversee electric utility activities.

In the provinces of Alberta and Ontario, responsibilities for reliability are clearly established as part of the regulator's mandate. In Alberta, under the Electric Utilities Act, the transmission administrator has responsibility for reliability management. The transmission administrator is responsible to set standards and requirements for system support services and to make arrangements for those services. The transmission administrator also may incorporate charges for these services into the tariff. Such tariff must be approved by the Alberta Energy and Utilities Board. In Ontario, under recent restructuring legislation, the Ontario Energy Board will be an independent regulator for the electricity industry. The independent market operator will make market rules, including reliability rules, which are subject to oversight of the Ontario Energy Board.

The reliability role varies in the other provinces. In British Columbia, under the Utilities Commission Act, the British Columbia Utilities Commission has authority to make orders about matters it considers necessary or advisable for the safety, convenience, and service to the public. In Québec, with new legislative amendments adopted in June 2000, the Régie de l'énergie has jurisdiction to regulate the transmission and distribution activities of Hydro-Québec to ensure that consumers are adequately supplied with electricity and pay just and reasonable rates. Furthermore, the transmission provider has to establish operating standards and technical requirements, including standards of reliability for its transmission system, and submit them to the Régie de l'énergie for approval. The generation is open to competition for new loads exceeding Hydro-Québec's current total level, and Hydro-Quebec keeps its hydraulic rights. New generation projects have to be approved by the government. In Manitoba, Manitoba Hydro may set standards and rules for the reliability of the transmission and distribution lines, and may refuse to connect any distribution or transmission line if the line is not operated in accordance with those standards.

Fuels

Natural Gas Outlook

Natural gas is a clean burning, economical, and widely available fuel. These desirable qualities are thrusting natural gas into prominence as a fuel for electric generation. Natural gas has historically been a major provider of energy to heat North American homes and fuel industry. However, all forecasters of future natural gas growth predict that electricity generation will be the market sector with the highest growth. Projected natural gas usage for electricity generation in the United States by 2010 is expected to be 12.2 TCF or four times the 1996 level.

According to the Energy Information Administration of the U.S. Department of Energy, electricity generators were third among the major users of natural gas from 1950 to the late 1980s in the United States. In the future, supply to electric generators could grow to become the largest or second largest consumer of natural gas by 2010, depending on the projection. The unknown in the variation in the future projections is the implementation of the carbon emission reductions that could be imposed by the Kyoto Protocol. Carbon emission reductions would likely cause the displacement of coal-fired sources with natural gas and renewables, which drives the future projections to higher levels.

Despite the increased demands, it is apparent that the natural gas resources are available. Adequate reserves exist and will continue to exist although the level of reserves is dependent on prices and vice versa. Higher prices will likely drive reserves higher but may also cause some developers to reconsider the economic feasibility of their proposed gas-fired projects. The vast majority of the United States supply will come from onshore and offshore sources in the lower 48-state region. The United States is expected to be importing varying portions of its natural gas supply during the assessment period, with Canada and Mexico being the main sources of the imports. Drilling activity appears to be limited only by the significant investment and timing required to build additional drilling rigs. Table 6 below contains a comparison of forecast U.S. long-run gas import requirements for Canadian gas and illustrates the point about higher prices resulting in greater supply.

Table 6— U.S. Demand for Canadian Gas

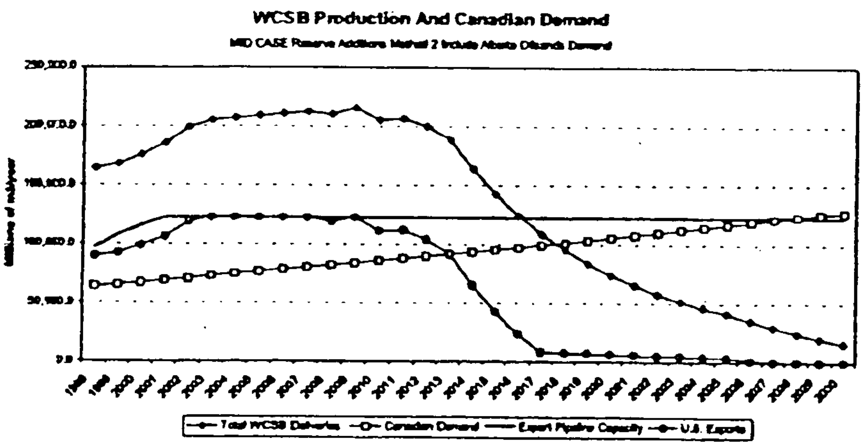
Projection	AEO2000			Other forecasts			
	Reference	Low economic growth	High economic growth	WEFA	GRI	DRI	AGA
Year	2015	2015	2015	2015	2015	2015	2015
Lower 48 wellhead price (1998 U.S. dollars per thousand cubic feet)	2.71	2.36	3.03	2.51	2.39*	2.41	2.33*
US Dry Gas Supply (TCF)	25.03	23.85	26.32	27.24	27.31	24.74	26.75
Imports (TCF)	4.85	4.51	5.12	5.13	3.51	5.25	4.15

Source: EIA Annual Energy Outlook 2000

The various forecasts indicate that the needs for Canadian gas in the United States will likely range between 4 and 5 TCF by the year 2015 and rise to between 5 and 5.5 TCF by 2020.

Countering the general optimism about future gas supplies, there is some concern surfacing in Canada about the ability to sustain high levels of exports to support a robust gas market in the United States. A study of potential conventional gas supply from the Canadian Western Sedimentary Basin (WCSB) undertaken by Optimum Energy Management Inc. (OEMI), indicates that potential supply from the WCSB to the United States may begin to dry up in the 2009/2010 time frame if efforts are not undertaken immediately to bring alternate Canadian supply sources forward. The OEMI reference case shows the WCSB beginning to go into decline around the year 2009 and by the year 2014 roughly only half of the existing and planned WCSB natural gas export pipeline capacity can be filled. By the year 2018, WCSB supplies are less than total Canadian domestic demand. (See Figure 20 on the next page)

Figure 20: Mid Case WCSB Marketable Natural Gas Supply and Canadian Demand



If WCSB export pipeline takeaway capacity is to be kept full, the conventional shortfall must be forthcoming from frontier gas (including the Scotian shelf displacing WCSB supplies to eastern Canada), coal bed methane, tight gas, imports, or various combinations thereof. The reference case shortfall that develops by the year 2010 is assumed to be met by frontier gas or coal bed methane. The shortfall is 4 billion cubic meters a year; by 2010, it is 75 billion cubic meters a year.

Assessment of the Natural Gas Infrastructure

Capacity additions to the transmission pipeline system will be required to support the increased usage scenarios. In the United States, the EIA expects that new capacity will be primarily out of Texas, Louisiana, and Oklahoma, through the South, to the southern coastal states, primarily Florida, in response to growing consumption. Later in the assessment period, capacity will be to the middle south. Adding capacity to the gas transmission system is subject to an arduous process, especially for projects requiring a new pipeline. Given historical responses of the industry to meet the need for capacity additions, EIA does not believe that pipeline capacity is likely to be a problem even in the carbon reduction scenarios.

> "Not only have the capabilities of the natural gas production, transmission, and distribution network grown significantly since 1990, but the quality and flexibility of service have improved as well. Additional substantial growth and improvement are expected over the next several years. Expanding interconnectivity within the pipeline grid, accompanied by improved services, will further integrate the natural gas production and delivery system, thereby helping to accommodate anticipated future demand." (EIA Natural Gas Monthly, April 1999)

Coal

In the United States, electricity production is by far the largest use for coal, with approximately 90% of the domestic coal production being devoted to this use. The future for coal use is tied to other factors, not the least of which is labor productivity. If labor productivity continues to improve, larger markets for coal can be expected. The EIA is forecasting that there will be increased coal use in the assessment period, particularly if oil prices increase. However, the growth in coal use will likely come from Western mines, which produces coal with significantly less sulfur content than most Eastern varieties. The penetration of Western coal into Eastern markets will be dependent, among other things, on the ability to keep transportation costs in control.

The transportation problems that plagued the coal distribution system in the past few years appear to have abated. Railroads in the United States deliver over two thirds of the total coal production. Therefore, any problems in the freight railroad community are likely to have dramatic impact on coal delivery, as occurred immediately after the Union Pacific-Southern Pacific merger.

Planning Issues

Generation Forecasting

For the near-term, the majority of projected new plant additions will use natural gas-fired combined cycle technology. These plants can be built in a very short time and therefore the generation planning horizon has shrunk accordingly. As a result of the short construction time requirements, there is an increasing trend to designate future resources as "unspecified," or to rely upon "unspecified" energy purchases. There may be reliance upon additional small stand-by generators and fuel cells to reduce generation resource requirements.

The industry is experimenting with changing the reserve margin requirements, sometimes in opposite directions. New York is reducing their requirement from 22 to 18%, while some Florida utilities have committed to voluntarily increase the requirement from 15 to 20% by 2004. Some discussions even suggest that a free market should meet the demands strictly based upon price signals and that reserve margin requirement is an obsolete concept.

Environmental restrictions, regulatory renewable requirements, unit retirements, industry restructuring, and fuel availability are just a few generation planning uncertainties on the horizon.

Generation Technologies Impacts

Despite the number of generation technologies that continue to be touted as commercially practical tools for future application, there has not been a trend of wide spread installations. If a practical method for financing the installation of the devices can be developed, fuel cells, micro-turbines, renewables, and other forms of distributed generation may be the technologies that will have the biggest impact on planning.

Existing units with connections to the transmission grid are prime candidates to take advantage of technologies such as re-powering, steam injection, and improved cooling process to increase the plant's total output.

On the longer-term horizon, the nuclear industry remains a technology that could be practical, especially in the view of predictions of increasing air pollution and global warming.

Distributed Generation — Resource Adequacy Effects

If distributed generation comes into widespread use as predicted, there will be a number of changes to the planning process. First, there will be a need for more information from the distribution companies regarding the number, location, and capacity of the sources. This information is required to plan for the protective relaying and reactive requirements as well as how the source might impact transmission capacity requirements. Secondly, there will be a need to develop interconnection agreements similar to the agreements required for interconnection to the transmission system.

In addition to the distributed generation applications installed at the distribution voltage level, there is a continuing trend in the number of transmission level customers adding cogeneration to serve their electrical as well as their steam requirements.

Renewables — NonDispatchability

Many regulatory agencies are mandating that retail energy providers entering the retail market provide renewable energy resources options to their customers. In some cases, the retail energy providers must meet a minimum percentage of their energy sales served with renewable energy resources. In Texas, the state has legislated that an additional 2,000 MW of renewable resources be built by 2009. The Energy Information Agency (EIA) estimates that renewable energy sources could account for between 11 and 22% of the U.S. generation market by 2020.

In many cases, the energy provided from the renewable resource is nondispatchable, i.e., when the sun shines the solar power is produced and all of its energy is utilized. As the amount of nondispatchable capacity grows, the remaining dispatchable units have to take a larger share of the responsibility of regulation and load following. The renewable resource can contribute to the energy requirements over a given time period, but the nondispatchable renewable resource provides no assurance that the energy can be delivered to meet peak demand.

Interregional Analysis and Planning

Regional planning will become an important tool to provide the coordination required between the generation, transmission, and load entities. More focus will have to be placed on analysis of generation availability and the ability to move energy from one Region to another.

The future configuration of "transmission companies" will also bring about a significant change in the scope of transmission studies, moving them from the local to the wide-area regional studies. The Entergy proposal and the Alliance proposal are examples of the new RTOs that are being considered for approval by FERC.

Electric Power Research Institute (EPRI) began a Probabilistic Analysis of Reliability of the North American Interconnections in 2000. The results of this study will provide additional tools for the wide-area analysis and will potentially spotlight areas that need transfer capability improvement.

Environmental Issues

The potential reliability impacts associated with environmental policy and regulatory actions depend largely on the details of their implementation, most of which are not yet known. Important factors in assessing potential reliability impacts include the stringency of the requirements, the length of compliance schedules, scope of geographic applicability, coincidence with other regulatory requirements, the amount of generation needing modification and retrofit outage duration, among others.

Generating capacity additions and transmission capacity availability will be critical to supporting increasing demand as environmental regulatory requirements, particularly for existing plants, become increasingly stringent. Announcements of new generating plant capacity commitments indicate that over 190,000 MW of new generating capacity will be operational by 2004. While not all of this capacity may actually materialize, much of it is already under development and is expected to significantly support increasing load in key regional markets. The ability of new capacity to allay environmental-related reliability concerns depends on its geographic and temporal coincidence with existing plants undergoing retrofits or shutdowns.

National Air Quality Standards and Goals

Over the next decade, requirements designed to meet national ambient air quality standards (NAAQS) and protect visibility in national parks and wilderness areas will come into force. Many of these requirements are not yet fully defined by the relevant regulatory bodies or are subject to further consideration by the courts, and thus their impact on reliability is uncertain.

Over the next year and a half, resolution is likely of several challenges to rules addressing ambient ozone. The broadest challenges, which are currently under review by the Supreme Court, relate to the role of cost in setting

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the NAAQS and legislative delegation to agency discretion in EPAs setting new NAAQS for ozone and particulate matter.

Of more immediate concern for the Northeast, Midwest, and Southeast are two intertwined rules, both of which impose NOx emission reduction requirements for the purpose of reducing regional ambient ozone levels. First is EPA's "NOx SIP Call" rule, which effectively would require the extensive installation of NOx control technology in as many as 22 states. While implementation of the SIP Call rule was held up by court challenges for more than a year, on March 3, 2000, the U.S. Court of Appeals for the D.C. Circuit upheld EPA's authority to require 19 Eastern states and D.C. to reduce NOx emissions under the rule.

The appeals court's March decision allows EPA to go forward with its stringent NOx reduction mandate in 19 states and the District of Columbia, requiring affected sources to achieve an average NOx emission rate of 0.15 lbs./mmBtu during the five-month ozone season. EPA will need to recalculate states' NOx budgets based on the remand portion of ruling. On June 22, 2000, the Appeals Court lifted its stay on implementation of the SIP Call rule, and set a new deadline of October 27, 2000 for states to submit their NOx implementation plans to EPA. However, the court extended the original May 2003 compliance deadline for meeting the required NOx reductions to May 2004. This extension should help utilities mitigate potential reliability impacts identified in previous RAS reports related to NOx compliance. For states that do not submit their implementation plans by the October deadline, EPA will impose a federal implementation plan or directly control sources through its "section 126" rule, which is an alternative approach to NOx reductions and is described further below.

Second, the "Section 126" rule effectively requires the same emission limits as the NOx SIP Call rule on the same schedule, but it applies to a smaller area and would be administered directly by EPA rather than the states. It was issued by EPA in December 1999 in response to petitions by Northeastern states under Clean Air Act section 126 for controls on upwind NOx emissions, which the states demonstrated prevent them from attaining the one-hour ambient air quality standard (.12 ppm) for ozone. The section 126 rule differs from the SIP Call rule in at least two other key respects. First, section 126 empowers EPA to regulate sources directly, so state implementation plans need not be revised. Second, because it responds only to petitioning states, the section 126 rule affects only 12 of the 22 states (and 60% of the emission reductions) targeted by the SIP Call rule. NOx reduction efforts are also under way in states other than those covered by EPA's NOx SIP Call and section 126 rules.

To comply with the EPA NOx SIP Call, outages of significant amounts of fossil-fueled generation will be necessary over the next few years to install the required NOx control devices. RAS directed a study of the potential reliability impacts of those retrofit outages on near-term resource adequacy. Results indicate that increased outage coordination in the Regions and the length of the retrofit window will be important factors in mitigating potential reliability impacts. Additional details are contained in a separate report issued by the RAS.

The results of these analyses suggest that any reduction in the amount of SCR retrofits needed for compliance, or extension of the retrofit window, would lessen any potential reliability impacts of the NOx SIP Call. For example, application of alternative NOx reduction technologies or other approaches that do not require additional retrofit outage time might reduce the number of units requiring SCR equipment, thereby reducing the impact of retrofits. Similarly, use of State Supplemental Allowance Credits proposed by the EPA could provide compliance flexibility, again reducing the SIP Call impacts.

Starting in 2003, EPA is scheduled to designate areas that are in non-attainment with the 1997 revisions to the ambient PM standards, which established a fine particle (2.5 microns or less, "PM2.5") standard. In addition to necessitating PM controls, these designations may cause states to consider additional controls on NOx and/or SO2, which are precursors to fine particles, to meet the fine PM standard. State regulations could require compliance within the decade in accordance with the Clean Air Act's "expeditiously as practicable" construct. However, the agency's fine PM standard is currently under review by the Supreme Court, which increases the uncertainties associated with the implementation and impact of the standard.

Fine particles are also significant contributors to regional haze. Under EPA's 1999 rules and schedules coordinated with PM2.5 SIP plans, haze progress requirements will be established through multi-state planning bodies and subsequently adopted by the States. Reductions of NOx and SO2 emissions from the generating sector will be evaluated and may be necessary to achieve compliance with both the NAAQS and the haze plans. In addition, in the initial stage of regional haze planning, power plants (first operational 1962–1977) will be evaluated for their impact on regional haze in national parks and wilderness areas. Where appropriate, site-specific Best Available Retrofit Technology (BART) on these plants may be required. The regional body addressing visibility in the West released draft rules for emission allowances and trading in August 2000.

Based on these developments, some additional requirements for SO2 and NOx emissions are likely. The impact on reliability of such additional standards is dependent on the length of time allowed for compliance with the standards and the number and type of units affected.

Plant Construction and Maintenance/Modification

For more than two decades, federal requirements for reviewing the air quality impacts of new, and modifications to existing, facilities have been increasingly complex. Over the last decade, EPA has discussed and proposed, but not finalized, revisions "reforming" these new source review (NSR) rules. The near-term outcome of these reform efforts, in concert with the outcome of a major EPA enforcement initiative against 44 coal-fired plants for alleged violations of these requirements, will have a decided but undetermined impact upon power generation. The regime governing what activities trigger NSR, which can involve lengthy permitting and air quality evaluations as well as best-technology requirements, largely determines whether and how operators pursue maintenance activities.

Hazardous Air Pollutants

EPA is required to determine, by December 15, 2000, whether regulation of hazardous air pollutant (HAP) (including mercury) emissions under Title III of the Act, after regulation under the other titles, is necessary and appropriate. This determination, if affirmative, would precipitate HAP regulation under Title III, in which case the appropriate Maximum Available Control Technology (MACT) level would be identified, and sources would have three years after this level is set to comply.

By congressional directive, EPA contracted with the National Academy of Sciences (NAS) to review the science on which to base a health-based reference dose for mercury, and must consider NAS's determination in its decision. The NAS released the executive summary of its report on July 11. The complete report is expected to be released before the end of August. While the report effectively validates EPA's approach to setting a public health "dose" level for mercury, it also appears to suggest that EPA has not adequately demonstrated that mercury emission reductions from coal-fired electricity generating units will reduce mercury exposure and health risks.

EPA is expected to decide whether to regulate HAPs from electric generation by the December 15 deadline, and to follow any affirmative decision with proposed standards by December 2003.

EPA is evaluating the use of a cap and trading implementation regime should it decide to regulate HAPs. EPA's regulatory approach and the development of commercially available control technology will be the key factors affecting potential reliability impacts. Since the reduction of mercury emissions would also result in the reduction of NOx and SO2, some have suggested that EPA's efforts for reducing these emissions should be coordinated.

Solid and Hazardous Waste

EPA in late May 2000 chose not to regulate coal combustion waste as hazardous waste under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The management of such ash will therefore continue subject to state law. However, EPA plans to develop national standards under RCRA Subtitle D to address coal combustion waste disposal in landfill or surface impoundments or placed in mines. These will include both the "remaining wastes" as well as "large volume" wastes previously exempted from Subtitle C regulation in 1993. These regulations may, in some cases, lead to increased management requirements for some plants in some areas. EPA has also said it will revise its May 22 determination including a need to regulate those wastes under RCRA Subtitle C.

Water Quality

In July 2000, EPA published final revisions to the Total Maximum Daily Loads (TMDL) program, which states use to meet federal water quality standards. The new approach charges states with developing detailed implementation plans for meeting each TMDL that they set. Since load levels may include nitrogen oxides, mercury, and other toxics, atmospheric deposition is one of the sources that states will consider and possibly restrict. Upwind power generation is a major source of emissions that may cause water quality impacts in downwind watersheds. EPA published its final TMDL rule on July 13. However, due to active congressional efforts to prohibit EPA from implementing the rule, the rule's status and effect remain uncertain.

EPA has recently issued a proposed rulemaking to establish uniform national technology-based requirements applicable to the location, design, construction, and capacity of cooling water intake structures at new power and manufacturing plants. The proposal maintains a categorical approach to encourage facilities to be built away from sensitive waters and removes required (habitat or species) restoration requirements. Facilities located in waters judged by EPA to be sensitive would be subject to requirements on intake flow volume, intake velocity, and recirculation, and could be required to install additional technologies beyond closed-cycle cooling. EPA lists various options in the proposal, among which is the opportunity to demonstrate that a chosen site will not significantly affect aquatic life and thereby gain less restrictive requirements. EPA is scheduled to propose and finalize rules for existing facility cooling water intake structures by the summer of 2001. No specific existing facility regulations have been proposed, but the agency could require expensive modifications to existing once-through cooling water systems, including possible conversions to cooling towers or seasonal restrictions on operations. If costs are too high, some generators may elect to completely shut down certain units or take the units out of service during fish spawning periods.

All plants using once-through cooling water discharge heated water to receiving waterbodies. Thermal discharges are subject to permit limits on temperature loads. Permitting agencies must review the thermal impacts of plants in every permit cycle, which are generally five to seven years. As states examine the factors that are leading to water quality impairment, they must look at all causes collectively. Therefore, plants that discharge heated water into streams that are suffering impairment from other causes, such as metals or nutrients, may face additional restrictions on their thermal discharges. These potential new restrictions could cause significant economic impacts at some plants, perhaps severe enough to lead to plant shutdowns.

The Administration has proposed a long-term strategy for restoring threatened and endangered salmon and steelhead in the Columbia River Basin in the Pacific Northwest. The plan does not call for breaching the four Lower Snake River dams at this time. Federal agencies will gauge the progress of the recovery strategy, while maintaining the dam-breaching option in the event that sufficient progress is not made. The proposed plan calls for habitat improvement measures for the river and surrounding tributaries that improve stream flows, remove barriers to fish migration, reform federally funded hatcheries to minimize harm to wild salmon while improving the survival rates of hatchery stocks, and cap harvest levels of protected species at current levels.

Greenhouse Gas Reductions/Limitations

The possibility of carbon reduction mandates under the Kyoto Protocol continues to be a subject of considerable controversy. Key members of Congress have continued to oppose its ratification, as well as EPA and others' perceived efforts to implement the Protocol prior to its ratification. Legislative efforts to provide a framework even for voluntary carbon-reduction credits have continued to lose momentum due to concerns that a crediting program would lend support for the Kyoto Protocol. While EPA had undertaken efforts to offer voluntary programs for carbon emission reductions, possible limitations in its authority and Congressional scrutiny have slowed such efforts. Other agencies, led by DOE, and some states are administering programs (e.g., promoting renewable energy) that may effectively reduce carbon emissions.

The emission reductions required by the Kyoto Protocol could have severe implications for the combustion of fossil fuels for electricity generation, which is a relatively cost-effective source of carbon emission reductions, compared with other sectors.

Reductions of carbon emissions from the electric power sector could occur either through a reduction in the demand for electricity, or through shifting reliance on more carbon-intensive fuels, such as coal, to less carbon intensive fuels, such as natural gas, renewables, and nuclear. There are significant policy questions surrounding the range of potential alternative technologies and fuels, including long-term availability, cost, safety, and disposal.

Other Environmental Issues

In certain situations, operating permits have been issued which limit the number of hours that an oil burning or natural gas burning combustion turbine can operate, especially during peak load periods. These local permitting restrictions could affect operation of peaking units when they are needed most.

Presently nuclear generation provides over 20% of the electrical energy requirements in the U.S. and Canada. Within the next ten years, 3,000 MW of nuclear capacity will face re-licensing in the United States. By 2015, almost 40% of the 103 nuclear units in the United States will face re-licensing. Nuclear generation can play an essential role in a carbon-emissions-limited society by providing significant capacity and energy without carbon emissions. This was recognized by the NRC in its recent re-licensing of the Calvert Cliffs Nuclear Plant.

Significant retirement of nuclear capacity (whether due to inability to re-license, economics, or for other reasons) could increase the need for emission reductions from fossil-fueled capacity, thus further increasing the potential impact on reliability. The construction of additional renewables capacity and the degree to which nuclear plants and other non-carbon emitting sources continue to operate will determine the extent of this impact on fossil-based capacity resources.

Siting of generating units is getting increasingly difficult due to environmental and public pressures. In Florida, Illinois, and Indiana, for example, community groups have lobbied state officials for moratoria on the construction of new generating facilities on the basis of environmental concerns. While these efforts have been unsuccessful, several developers have chosen to abandon selected projects due to local opposition. Reliability could be impacted if the construction of merchant plants is delayed or cancelled in significant amounts and/or key locations.

Siting challenges can significantly contribute to difficulty and delays in building new transmission facilities. Siting authorities may hesitate to grant approvals when they do not perceive benefits for their constituencies. American Electric Power's proposed 765 kV transmission line between West Virginia and Virginia is an example of the regulatory difficulties the industry faces when trying to expand transmission system capabilities across multiple state jurisdictions. This project, originally scheduled for service in May 1998, continues to be delayed and is now scheduled for service in June 2004. This delay increases the potential for widespread interruptions. Although operating procedures can reduce the risk of interruptions, the likelihood of such power outages will increase until a system expansion can be completed.

ECAR

The bulk electric systems in ECAR will continue to perform well in meeting the forecast demand obligations over a wide range of anticipated system conditions as long as established operating limits and procedures are followed and proposed projects are completed in a timely manner. There remains particular concern on the certification difficulties of American Electric Power's 765 kV line between West Virginia and Virginia, which is needed to guard against the potential for widespread interruptions. Announced capacity resource projects will satisfy the Region's criterion for resource adequacy through 2004 if at least 22% of the capacity in these projects are completed and adequate capacity resources are available when needed, outside the Region. This assumes that the average annual generating unit availability is maintained at or above levels experienced in recent years.

As the industry moves toward increased competition, ECAR's membership is striving to meet the challenge of maintaining the adequacy and security of its bulk electric systems. ECAR continues to review and update its organizational structure, governance provisions, reliability assessment process, and technical documents and guides to ensure that reliability is maintained in the changing environment and that ECAR is in compliance with NERC Policies and Standards. Full ECAR membership has been opened to its associate members. ECAR also continues to enhance its Open Access Same-time Information System (OASIS) to improve the maintainability and availability of the system.

ECAR Assessment Process

In ECAR, planning for facility additions is done by individual member utilities. Regional reliability assessments are performed to ensure that member plans are well coordinated and that Regional reliability criteria are met. The ECAR Generation Resources Panel and Transmission System Performance Panel perform assessments under direction of the ECAR Coordination Review Committee. The results of these assessments are documented in reports available on the ECAR website, www.ecar.org. ECAR assessment procedures are applied to all generation and transmission facilities that might significantly impact bulk electric system reliability. These assessments consider ECAR as a single integrated system. The security impact of interactions with neighboring Regions is assessed by participation in several interregional groups such as MAAC-ECAR-NPCC (MEN), VACAR-ECAR-MAAC (VEM), and MAIN-ECAR-TVA (MET). Generation resource assessments of the ECAR systems on a Region-wide basis are performed annually for a planning horizon of up to ten years, and semiannual seasonal assessments are made for the upcoming peak demand seasons. Transmission assessments are performed regularly for selected future years out to the planning horizon and semiannually for the near term. If deficiencies are discovered during this process, the member system with the deficiency is asked to explain what remedial action will be taken.

Demand and Energy

Throughout the assessment period, the peak total internal demand of ECAR members is expected to continue to occur during the summer with a 1.7% average annual growth rate, about the same as last year. Current resource plans developed by ECAR members project a reliance on direct controlled and interruptible load management programs of about 3,900 MW by 2009 and plans also include about 300 MW of new passive demand-side management programs not controlled by system operators. With interruptible loads and loads under demand-side management removed, ECAR's net internal demand is projected to reach about 107,000 MW in 2009.

Resource Assessment

ECAR members develop ten-year capacity plans that reflect the new capacity necessary to reliably serve demand and energy in the Region. These plans project additions of or contracts for about 10,400 MW of new capacity. Of the new capacity, about 8,700 MW are projected to be short lead-time combustion turbines. Capacity margins based on the ECAR ten-year capacity plan, for net internal demand, are expected to be in the 9–11% range in the 2000–2004 timeframe, but decline to a minimum of about 7% in 2009. If capacity reported as planned is excluded, capacity margins will become negative in 2005.

The ECAR assessment indicates that by 2004, there will be a need to supplement the capacity presently under construction by an additional 15,000 MW of capacity resources. ECAR currently has an import capability of about 9,500 MW. In the absence of increased import capability, there will be a need for at least 5,500 MW of additional generating capacity to be physically connected within the ECAR Region. This requirement means that about 22% of the announced new merchant capacity in the Region will need to be installed by 2004. ECAR annually conducts an extensive probabilistic assessment of long-term capacity margin adequacy. It considers the Regional peak demand profile and the generation availability of ECAR members to assess ECAR-wide reliability against a criterion of one to ten days per year of Dependence on Supplemental Capacity Resources (DSCR). Supplemental Capacity Resources include assistance from neighboring Regions, contractually interruptible demands, and direct control load management. One of the most critical parameters affecting the adequacy of bulk electric supply in ECAR is generation availability. The 2000 capacity margin assessment determined that the annual generation availability must remain at or above 79% to meet the DSCR criterion throughout the assessment period. Actual availability in ECAR has averaged 81% or better through the past five and ten year periods. It has not been below 79% availability in the past ten years to meet the demand requirements.

ECAR believes that the aging of generating capacity will necessitate increased maintenance and lengthened outages. By the year 2009, about 66% of the capacity in ECAR will be 30 or more years old and about 29% will be 40 or more years old. ECAR members recognize the challenges in maintaining the high levels of generation availability experienced in recent years but expect to meet them. As margins continue to decline, coordination of maintenance schedules will become more important and difficult.

Coal, the predominant fuel used within the ECAR Region, is expected to supply about 69% of the total electrical capacity requirements in the year 2009. Although compliance plans to meet Phase 1 of the Clean Air Act Amendments of 1990 (CAAA) have been implemented, some uncertainty still remains in NOx regulation compliance. The ECAR Region is presently analyzing the reliability impact of the issuance by the EPA of NOx State Implementation Plans that are implemented by May 1, 2000. The ECAR Region has about 82,000 MW of active coal capacity. In a survey conducted by the Region, which covered 79,500 MW of coal capacity, indicated that about 52,300 MW needs to be retrofitted with selective catalytic reduction (SCR) equipment. The potential need to extend the spring and fall planned outages between now and 2003 to accommodate these retrofits presents a reliability challenge for the Region.

Transmission Assessment

The transmission networks in ECAR are expected to meet adequacy and security criteria over a wide range of anticipated system conditions as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service when required. The Michigan systems are in the process of installing phase-angle regulators (PAR) in the remaining three interconnections between the Detroit Edison and Ontario systems but the PARs will not have full impact until after summer 2000. With the PAR addition, the power flows circulating around Lake Erie that have often limited the ability of the Michigan systems to receive firm purchases from Ontario can be controlled to improve the transfer capability between ECAR and NPCC (Ontario). Local transmission overloads are possible during some generation and transmission contingencies. However, ECAR members use operating procedures to effectively mitigate such overloads. Current plans call for the addition of about 456 miles of extra-high voltage (EHV) transmission lines (230 kV and above) that are expected to enhance and strengthen the bulk transmission network. Included in these planned additions is the American Electric Power (AEP) 765 kV transmission line between West Virginia and Virginia. This project, originally scheduled for service in May 1998, continues to encounter certification difficulties, although some progress has been made during the past year. The earliest date that this project can be completed is June 2004. A tri-regional assessment of the reliability impacts of this project concluded that a reliability risk exists due to the delay of this project. Although operating procedures can minimize the risk of widespread interruptions, the likelihood of such power outages will increase until the project can be completed.

Operations Assessment

Three security coordinators maintain reliability of the transmission system in the ECAR Region. AEP is the security coordinator that monitors power flows between ECAR and Regions to the west and southwest. Allegheny Power is the security coordinator that monitors power flows between ECAR and the Regions to the east and southeast. The Michigan Electric Coordinated Systems (MECS) is the security coordinator that monitors power flows circulating around Lake Erie. Each of these security coordinators works with security coordinators from surrounding Regions and uses the NERC transmission loading relief (TLR) procedure to maintain the reliability of the interconnected transmission network. Critical transmission interface loadings within ECAR are also monitored and controlled by ECAR members.

In addition to the NERC TLR procedure, the reliability coordination plan (RCP) may be used by systems in eastern ECAR, MAAC, and the VACAR Subregion of SERC to curtail or limit west-to-east transfers to ensure adequate reliability in that part of the system.

Two new control areas have been conditionally approved and are now operating in the ECAR Region. These generation-only control areas are operated by Enron, and will be considered for full control area status after six-months of operation.

The East Central Area Reliability Coordination Agreement (ECAR) membership currently consists of 16 full members and 34 associate members serving either all or parts of the states of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland, and Tennessee.

ERCOT

Near-term generation resource requirements will be met by the existing reserves of generation capacity of the utilities, qualified facility cogeneration plants, and new merchant plants. In addition, new merchant generation capacity planned or under construction will add approximately 5,000 MW in 2000. Beyond the year 2000, many new proposals for generation resources have been made and, as they are completed, will maintain planning reserves at a reliable level. While the majority of new resources are gas-fired, high-efficiency gas turbine combined cycle plants, approximately 200 MW of wind generation has been installed and 300 MW additional wind generation has been proposed.

The transmission system required to move energy from the generation location to the demand centers is adequate for the near term. In 2000, during high demand periods, a number of transmission constraints may be experienced, and Transmission Load Relief Procedures may need to be invoked by the ERCOT Independent System Operator. The constraints will continue to limit some of the transfers until new transmission projects are completed. Future transmission required for interconnection of new generation resources will be reliable only if sufficient time exist to acquire regulatory approval, acquire right of way, and build facilities in the time period between the commitment of the generator developer to construct and the completion of the new generation facility.

Assessment Process

The Engineering Subcommittee produces and performs the power flows required for the members to assess the reliability of their transmission systems. An annual report is made to report transfer capabilities and the results of selected contingencies. The studies indicate that the interchange requirements and contingency evaluation will meet the ERCOT Planning Criteria. The study work done by the subcommittee is not intended to be an exhaustive study of all the contingencies that would be necessary to test the system and prove the reliability criteria. Rather, it is the responsibility of each member to test their systems, and report to the subcommittee those issues that might pose a future reliability concern.

In 1999, all of the ERCOT subcommittees completed the conversion of the ERCOT Guides, Procedures, and Criteria to be consistent with NERC Standards. The 1999 Phase I review of ERCOT found ERCOT in compliance with NERC Standards.

Demand and Energy

The actual 1999 ERCOT summer demand grew to 54,913 MW from 53,689 MW, a 2.3% increase. This demand includes serving interruptible demands. For the period 1990–1999, the average annual compound growth rate has been 3.1%.

The actual ERCOT energy consumption fell slightly from 269,718 GWH to 268,622 GWH, a 0.4% decrease. For the period 1990–1999 the compound annual growth rate has been 2.8%.

The average annual growth rate in ERCOT's summer peak demand is projected to be 2.7% for the 2000–2010 period. The projected annual growth for energy is 2.3%.

Resource Assessment

Loss-of-load-probability (LOLP) and loss-of-load-hours (LOLH) reliability studies were not made in 1999. The ability to continue making these types of calculations in the future may be compromised by the lack of data concerning performance and forced outage rates and the inability to identify future generating unit additions.

The future resources that have been specified in the Capacity-Demand-Reserve Working Papers as unspecified have brought many new proposals for new generation sources and interconnections. In the period since January 1, 1998, over 35,000 MW of new capacity has been proposed for construction in the 1999–2003 time frame. While it is unlikely that all of the proposed generation will be built, the forecast for new generation continues to improve. An estimated 5,000 MW of generation will be completed in 2000. In addition to the merchant plants scheduled to be built in the ERCOT area, several plants will be built at the border of ERCOT and the SPP Region. In 2000, the 830 MW Tenaska Frontier Plant will be connected and be able to supply energy to the ERCOT or the SPP Regions.

ERCOT should continue to have adequate resource reliability as long as the entities responsible for securing capacity resources allow sufficient lead time in their acquisition process to ensure the capacity and associated transmission support is available when required.

Transmission Assessment

The transmission system is experiencing constraints during high demand periods. The expected 2000 transmission line loading for transfers from south to north ERCOT continue to grow and will require that ERCOT implement Transmission Line Load Relief Procedures. For long-term transmission planning, ERCOT has approved new transmission lines to be constructed to address these constraints and strengthen the bulk transmission system to accommodate new generation and increased demands. The timing of these new facilities will be important to reliability. ERCOT is currently experiencing much higher than anticipated demand growth rates and is projecting annual demand growth at slightly higher than 3% in the next few years. New generation is needed and is being proposed by the generation entities; however, timing again is critical. ERCOT continues to monitor and analyze transmission service and generation interconnection requests to assess reserve levels and propose new transmission projects to efficiently transport generation to demand centers.

Operations Assessment

The ERCOT-ISO that went into operation in January 1997 continues to schedule and approve all transactions and to make daily assessments of transfer capability and security based on load flow simulations of the system that include expected outage conditions.

The Electric Reliability Council of Texas (ERCOT) is comprised of six municipal G & Ts, six cooperative G & Ts and river authorities, four investor-owned utilities, 11 independent power producers, 22 power marketers, and 13 transmission-dependent utilities. ERCOT members serve over 12 million customers (and about 200,000 square miles or 73% of Texas) and account for over 63,000 MW of generating capacity and 32,000 miles of transmission lines.

FRCC

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating capacity reserves and transmission system capability to meet the Regional reserve margin standard throughout the 2000–2009 assessment period.

FRCC was created in October 1996 to ensure bulk electric system reliability in Florida. FRCC members regularly exchange information related to the reliability of the bulk electric system in both planning and operating areas. As a NERC Region, FRCC has developed a formal reliability assessment process by which a committee and working group structure is utilized to annually review and assess reliability issues that either exist or have potential for developing. The Reliability Assessment Group (RAG) administers this process and determines what planning and operating studies will be performed during the year to address those issues.

RAG is also the mechanism for collecting, assembling, and assessing the Regional EIA-411 Report, and the FRCC Load and Resource Plan, which is submitted annually to the Florida Public Service Commission.

Assessment Process

Within the FRCC Region, the members plan for facility additions on an individual basis. However, in addition to their own databases, they use data developed as a group under FRCC to assess the impact of neighboring systems and to adjust their plans accordingly. FRCC maintains power flow, stability, and short-circuit databases for the use of FRCC and its members.

Annually, the Reliability Assessment Group (RAG) reviews existing and expected short and long term conditions within the Region. RAG, which includes planning, marketing, and operating members, makes recommendations to the Engineering and Operating Committees on the studies that should be conducted by the working groups for the next year. These reliability studies encompass Regional generation and transmission adequacy and security including import/export capabilities.

Upon completion of the reliability studies, reports that include results, conclusions, and recommendations are published. RAG monitors actions taken to meet reliability criteria as a result of all study report recommendations.

FRCC has also developed a compliance program to ensure member and Regional compliance with FRCC and NERC Standards.

Demand and Energy

FRCC is historically a winter-peaking Region. However, because the Region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer. Therefore, it is possible for the annual peak to occur in the summer. The projected annual net peak demand and the energy growth rates for Florida for the next ten years are 2.3 and 2.1%, respectively.

Resource Assessment

The reserve margins for the ten-year assessment period (2000–2009) are at or above the FRCC reserve margin standard of 15%. The Resource Working Group (RWG), as part of its overall assessment of resource adequacy, determines reserve margin for both summer and winter based on system conditions at the time of the system seasonal peaks. These system peaks are assumed to be in the months of January and August for planning and assessment purposes. The reserve margin is determined by utilizing the net of the total peak demand (which includes the projected effects of conservation) minus the effects of exercising load management and interruptible loads during the peak demand periods. FRCC members are projecting the net addition (i.e., additions less removals) of 11,418 MW of new capacity over the next ten years. Of this, 10,971 MW are projected to be natural gas-fired combined cycle.

The increased reliance on generation that requires a short build time, such as combined cycle and combustion turbine units that burn natural gas, is evident in the assessment. This technology gives the demand serving entities considerable flexibility in reacting to a dynamic marketplace in today's changing and competitive environment. This changing environment will continue to place more emphasis on increased efficiency of existing units.

Transmission Assessment

The FRCC Stability Working Group (SWG) has completed an assessment of outage performance out to 2005 based on expected power import from the Southern Subregion of SERC to the FRCC, and found no problems. The SWG has also completed and extensive investigation of delayed clearing faults. Only one potential violation of Category C performance requirements was identified. Although the overloads and low voltages can be eliminated by a series of operating procedures, modifications are being evaluated that would mitigate this potential violation.

In the past, the SWG studies had identified a Central Florida/South Florida swing mode that was poorly damped for certain 230 kV and 500 kV circuit outages. The installation of power system stabilizers at key plants in 1998 has improved damping of this swing mode to an acceptable degree in the near term. In the long term, some of the new units might require power system stabilizers.

The FRCC Transmission Working Group (TWG) completed a ten-year, intraregional study that comprehensively evaluated FRCC transmission system under normal and outage conditions for the years 2001, 2002, 2004, 2006, and 2008 based on the expected power import from the Southern Sub-region of SERC to the FRCC. The results of this study indicate that any thermal or voltage violations can be successfully managed in the short term by operator intervention including generation redispatch, sectionalizing, reactive device control, and transformer tap adjustments. In the long term, violations of criteria can be resolved by planned transmission projects where there is adequate time to monitor trends and construct required network upgrades. Individual members plan to construct 416 miles of 230 kV during the 2000–2009 assessment period.

The Florida/Southern Planning Task Force performs interregional transmission studies as required to evaluate the transfer capability between the Southern Subregion of SERC and FRCC.

Operations Assessment

FRCC has both a Security Coordinator and an Operations Planning Coordinator who monitor system conditions and evaluate near-term operating conditions. FRCC has a detailed Security Process that gives the Security Coordinator the authority to direct actions to ensure the real-time security of the bulk electric system in the Region.

The Security Coordinator uses a Region-wide Security Analysis Program and a "Look-Ahead" Program to evaluate current system conditions. These programs use databases that are updated with data from operating members on an as-needed basis throughout the day. The procedures in the Security Process are being evaluated and updated on an ongoing basis to ensure Regional reliability, conformance to FRCC procedures, and adherence to NERC Standards and Policies.

The Florida Reliability Coordinating Council (FRCC) membership includes 34 members, of which 12 operate Control Areas in the Florida Peninsula. FRCC membership includes investor-owned utilities, cooperative systems, municipals, power marketers, and independent power producers. The Region covers about 50,000 square miles.

MAAC

Generation resources are expected to be adequate in the MAAC Region over the next five years. Requests to interconnect more than 38,000 MW of new generating capacity to the transmission system in MAAC by 2005 are currently being evaluated by PJM in accordance with the PJM Open Access Tariff. MAAC believes that sufficient capacity will be added to meet the MAAC adequacy objective that the probability of demand exceeding available resources will be no greater, on the average, than one day in ten years.

Based on identified system enhancements, the transmission capability over the next five years is expected to meet MAAC Criteria requirements. In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2005. These projects are currently being evaluated by PJM, through the PJM Regional Transmission Expansion Planning Process. It is reasonable to expect sufficient transmission will be added to meet the MAAC Criteria.

Maintaining Reliability in the Changing Environment

As the industry moves rapidly toward retail customer choice, the Mid-Atlantic Area Council (MAAC) is addressing the challenge of maintaining the adequacy and security of the bulk power electric systems. With wholesale open access, some Regional demand is supplied under contracts that have no commitments beyond the contract duration. It is likely that under retail access there will be a dramatic increase in the number of these capacity contracts and a decrease in the duration of these contracts. Retail customer choice is available to all customers in Pennsylvania. Similar regulations have been passed in New Jersey, Delaware, and Maryland. The future challenge will be to develop a process to provide adequate capacity resources recognizing that a large amount of demand can switch suppliers on a billing cycle basis. MAAC continues to review its organizational structure, governance provisions, reliability assessment process, and technical documents and guides, to ensure that reliability will be maintained in the changing environment, and that MAAC will be in full compliance with the NERC Planning Standards and Operating Policies.

MAAC and the PJM ISO

The Mid-Atlantic Area Council (MAAC) is unique among Regional councils in that it contains only one control area: PJM Interconnection, L.L.C. PJM's service area includes all or part of Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia. Six state and district regulatory commissions and the Federal Energy Regulatory Commission (FERC) have jurisdiction within the PJM control area.

Implementation of the PJM Open Access Transmission Tariff on April 1, 1997 facilitated the emergence of PJM's Regional, bid-based energy market, the nation's first.

MAAC Assessment Process

Transmission assessments are performed regularly for selected future years out to the planning horizon, and semiannually for the near-term system. If deficiencies are discovered during this process, the member with the deficiency is required to explain what remedial action will be taken. Each year the necessary reserves to remain at a loss of load probability of one day in ten years are calculated for the ten-year planning horizon. An agreed to reserve requirement is then set for the planning period two years in the future.

The security impact of interactions with neighboring Regions is assessed by participation in MAAC-ECAR-NPCC (MEN) and VACAR-ECAR-MAAC (VEM) interregional study groups.

PJM has established a Regional Transmission Expansion Process that will be utilized to enhance the MAAC bulk power system if MAAC reliability assessments or NERC Standards compliance deem system expansion necessary.

Demand and Energy

Net peak demand and energy forecasts for 2000 decreased in comparison to the 1999 forecasts. The net peak demand growth rate recedes to 1.4% from last year's 1.6%. Geographic zone growth rates vary from 0.4 to 2.4%. The energy growth rate also shrinks slightly to 1.5 from 1.6%.

Installed Generating Capacity Requirements

Generation resources are expected to be adequate in the MAAC Region over the next five years. Requests to interconnect more than 38,000 MW of new generating capacity to the transmission system in MAAC by 2005 are currently being evaluated by PJM in accordance with the PJM Open Access Tariff. While it is early in the process at the time of this writing to know just how many projects will actually be built, it is reasonable to expect sufficient capacity will be added to meet the MAAC adequacy objective of having sufficient capacity to insure that the probability of demand exceeding available resources will be no greater, on the average, than one day in ten years.

The concerns identified in earlier assessments about the continued availability of ALM appear to have been resolved. It appears that ALM will continue to be available in the retail open access market based on actual experience in 1999 with retail choice in Pennsylvania.

There are, however, two areas of concern that warrant monitoring by MAAC. One concern is the possible effects of Environmental Protection Agency regulations requiring abatement of NOx by 2003 in all states within the MAAC Region. The extent to which meeting these regulations results in retirement of existing generating units or long outages of existing units for capital modifications will be closely monitored and evaluated over the next two years. The second concern is the extent to which market conditions may result in off-system sales of capacity and how that may affect availability of resources in MAAC, particularly during peak periods. To ensure load-serving entities have access to available capacity resources, PJM has established daily and monthly capacity markets.

Transmission Adequacy and Security Requirements

Based on identified system enhancements the transmission capability over the next five years is expected to meet MAAC Criteria requirements. In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2005. These projects are currently being evaluated by PJM through the PJM Regional Transmission Expansion Planning Process. While it is early in the process at the time of this writing to know just how many projects will actually be installed and the exact configuration of the projects, it is reasonable to expect sufficient transmission will be added to meet the MAAC Criteria.

Capacity Additions and Transmission Planning

The members rely on PJM to prepare a plan for the enhancement and expansion of transmission facilities to meet demands for firm transmission service in the PJM control area. Based on data from the transmission owners and input from an Advisory Committee, PJM has the responsibility to prepare a Regional Transmission Expansion Plan that consolidates the transmission needs of the entire region into a single plan for maintaining reliability. The Plan is subject to approval by the PJM Board of Managers.

The MAAC staff coordinates the planning of generation to meet combined peak demands of the PJM control area. They coordinate planning of the interconnected bulk power transmission system to deliver energy reliably and economically to customers. MAAC staff also conducts many specialized planning studies within the pool and with surrounding entities.

Relaying and Protective Devices

As a result of the 1998 MAAC Reliability Assessment, several initiatives were undertaken by the PJM Relay Subcommittee to review existing procedures, and establish procedures for the collection and monitoring of relaying and protective devices on the MAAC bulk power system. In addition, the PJM Transmission and Substation Design Subcommittee investigated the nonfault operations caused by defective 500 kV circuit breakers. As a result:

- The PJM Relay Subcommittee has established procedures for the collection of relay operation data at all voltage levels that will ensure compliance with NERC Planning Standards requirements.

- A review of the procedures for generator underfrequency protection and underfrequency load shedding data collection was conducted. The PJM Relay Subcommittee database needs to be supplemented with corresponding demand and generation data to become compliant with NERC reporting requirements. Procedures are being put in place through the MAAC Information Management Subcommittee to collect the required data.

- In addition, the PJM Transmission and Substation Design Subcommittee initiated a review of recent trends in circuit breaker performance associated with non-fault operations and multiple facility trips involving circuit breaker malfunctions. Several failure mechanisms have been identified for certain types of bushings that were applied to breakers from 1954 through 1986. The transmission owners recognize the situation and are addressing the problem. Transmission owners have been requested to provide reports to MAAC on action taken to address this problem.

Network Transfer Capability

The concerns identified in earlier assessments regarding capacity emergency transfer capability in certain subareas of MAAC have not been fully resolved. As generation projects become firm, fewer or different transmission reinforcement projects will be required to meet subarea deliverability requirements; it is a matter of balancing the generation and transmission solutions to meet capacity emergency transfer capability objectives.

In previous assessments, several portions of the MAAC bulk power system that were found to meet the deliverability objective with little or no margin and were retested for the 2004/2005 system with the following results.

- The deliverability of capacity for the eastern PJM Region needs to be carefully analyzed. Appropriate reinforcement plans should be developed to achieve compliance if the Region is found not in compliance with its deliverability objective. A 200 MW margin was calculated for the 2000/2001 planning period. Although scheduled capacity additions should improve deliverability, the region will continue to require careful monitoring. Future margins will ultimately depend on how many of the announced projects are actually completed.

- The Delmarva Peninsula Subarea of Conectiv meets its deliverability objective for the planning period with a margin in excess of 200 MW. When evaluated last year based on the demand forecast available at the time, there was no margin available during the 2000/2001 planning period. The observed increase in the margin can be attributed to a number of transmission upgrades and generation projects.

- Reinforcement of the bulk power system in the Cardiff/Landis area of the Atlantic Electric subarea of Conectiv will be required by 2004 to be in compliance with the deliverability requirement. A potential reinforcement to bring this area into compliance is the addition of a second New Freedom-Cardiff 230 kV circuit and a 230 kV ring bus at Cardiff in 2004.

- The deliverability of capacity for east central New Jersey Subarea needs to be carefully analyzed. Transmission reinforcement plans have been developed to achieve compliance if planned generation projects do not come to fruition. Future margins will ultimately depend on how many of the announced projects are actually completed and the extent of transmission reinforcements necessary for the subarea to meet its deliverability obligation.

Operations Responsibilities

The PJM staff centrally forecasts, schedules, and coordinates the operation of generating units, bilateral transactions, and the spot energy market to meet demand requirements. To maintain a reliable and secure electric system, PJM monitors, evaluates, and coordinates the operation of over 8,000 miles of high-voltage transmission lines. The PJM OASIS is used to reserve transmission service. Operations are closely coordinated with neighboring control areas, and information is exchanged to enable real-time security assessments of the transmission grid.

The Mid-Atlantic Area Council (MAAC) serves over 22 million people in a nearly 50,000 square mile area in the Mid-Atlantic Region. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small part of Virginia. MAAC comprises less than two percent of the land area of the contiguous United States but serves eight percent of the electrical demand. There are 13 full and 27 associate members of MAAC.

MAIN

Demand and Energy

MAIN forecasts its summer peak demand for the 2000–2009 period to increase at an average annual rate of about 1.6%, slightly higher than last year's projected rate. The actual Mid-America Interconnected Network (MAIN) 1999 peak demand of 49,027 MW was about 7.6% higher than last year's forecast.

The projected average annual growth rate of electrical energy for 2000–2009 is 1.5%, slightly above last year's forecast rate. Actual energy use in MAIN in 1999 was 243,278 GWh, which was slightly higher than the 1999 forecast.

Resource Assessment

More than 3,000 MW of new capacity resources are scheduled to be added within the MAIN Region in 2000. It is expected that net capacity added in 2001 will be even greater than in 2000. Given this large increase in capacity, long-term reserve margins for MAIN as a whole are projected to be within or exceed the recommended range of 17 to 20% (14.5 to 16.7% capacity margin). The majority of planned capacity additions in MAIN are short lead-time combustion turbine peaking units owned by merchant power producers.

MAIN is expected to have adequate installed generating capacity to meet its one-day-in-ten-years criterion (0.1 day or less per year LOLE). This is based on the projected yearly reserve margins for MAIN, an assumed adequate import capability, and the assumption that other Regions carry on average the same level of reserves as MAIN.

Transmission Assessment

For the summer of 2000, MAIN expects interregional import capability to be adequate, although it is concerned about its lower-than-historic non-simultaneous import capability from ECAR. Within MAIN, the Wisconsin Upper Michigan Interconnected System (WUMS) import capability is inadequate. The early completion of Commonwealth Edison's Lockport-Lombard (345 kV double circuit) line due to an accelerated construction schedule has improved import capability for MAIN and the WUMS subregion. However, the western (Eau Claire — Arpin 345 kV) interface within the WUMS subregion continues to constrain MAIN and WUMS imports from the west. This reliability concern has been demonstrated in the Wisconsin Reliability Assessment Organization report. Additional details of the MAIN assessment are contained in the *NERC 2000 Summer Assessment* report.

For the planning horizon, MAIN expects its transmission system to perform adequately if reinforcements are installed as planned. This assessment is based on historic and current analyses used to judge compliance with NERC Planning Standards I.A.S1 through I.A.S4. Specifically, for Standards S1 and S2, all MAIN transmission owners assessed 2000 summer and 2004 summer conditions as requested by MAIN; some owners also included assessments of other time periods. For Standards S3 and S4, MAIN made its assessment using its latest Regional extreme disturbance study for 2002, a Regional study for December 31, 1999 and assessments from in-house studies provided by MAIN transmission owners. Mitigation plans, including the use of operating guides in MAIN, have been identified to provide acceptable system performance if the planned facilities are not available when scheduled.

Major reinforcements that may impact the adequacy of MAIN's transmission system for the planning horizon include the following:

- Lockport-Lombard 345 kV double circuit line (completed summer 2000)
- Oak Creek-Arcadian 345 kV project (2001)
- Weston (MAIN)-Arrowhead (MAPP) 345 kV line (2003)
- Burnham-Taylor 345 kV line (2004)

The impact of merchant generation has become a major concern. Uncertainties exist regarding size, location, and in-service dates of these new plants. As a result, the overall planning process has become increasingly challenging.

MAIN Assessment Process

MAIN's individual member utilities plan their own facility additions. MAIN performs Regional assessments, under the direction of the MAIN Adequacy Committee (AC), to ensure that members' plans are coordinated to provide a reliable system. The AC's Transmission Task Force performs short-term and long-term studies of the adequacy of MAIN's transmission system. Over a period of years these studies, along with MAIN member studies, are expected to test the system for compliance with the NERC Planning Standards, specifically, Standards I.A.S1 through I.A.S4.

The AC's MAIN Guide 6 study group analyzes the reliability of MAIN's generation system using the loss-of-load-probability (LOLP) / loss-of-load-expectation (LOLE) methodology. This methodology accounts for load forecast uncertainty due to all factors, including weather and diversity among NERC Regions.

MAIN works with its neighboring Regions to analyze interregional reliability through its participation in the MAIN-ECAR-TVA (MET), MAIN-MAPP-SPP (MMS), and MAIN-SERC WEST (MSw) groups. Individual MAIN members also initiate studies with each other and with entities in other Regions to assess and improve the performance of the transmission system.

Operations Assessment

The MAIN Coordination Center (MCC) in Lombard, Illinois, is the security center as well as the OASIS node for the region. (The MCC provides OASIS service to MAIN members as well as Entergy, TVA, and Associated Electric Cooperative.) The MCC performs ATC studies for its members on a daily basis and uses the NERC SDX (system data exchange) to model adjacent systems. Nearly all security and ATC staff have passed the NERC operator certification test. At least one certified engineer is on shift at all times.

During the peak demand summer months, MAIN conducts a morning conference call in order to coordinate operations for the upcoming day. Adjacent councils, their members, and regulatory bodies also participate.

MAIN uses the NERC transmission loading relief (TLR) procedure as its primary line loading relief tool.

Progress is continuing on the MAIN Regional Security Application Network. This system supports a 15,000 bus state estimator model with high-speed contingency checking. The system continues to be refined and upgraded with enhancements.

MAIN is now a reserve-sharing group. The automated callable reserve system is being redesigned and will be incorporated into MAINNet II, MAIN's internal regional communication network.

In the spring of 2000, each MAIN member who served native demand in the MAIN Region was again audited by an independent auditor to determine the status of the member's power supply resources for meeting its expected summer demand.

The 43 members of the Mid-America Interconnected Network (MAIN) include 15 control areas and 28 other organizations involved in Regional energy markets. MAIN is a summer-peaking Region serving a population of 20 million in a geographic area of 150,000 square miles. MAIN encompasses portions of Iowa and Minnesota, most of Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the Upper Peninsula of Michigan.

MAPP

Planned resources in the MAPP-U.S. area are judged to be inadequate to supply the forecast annual summer peak demand growth through the next ten years. When demand forecast uncertainty is taken into account, the Region may be capacity deficit by 2001 summer and nearly 5,300 MW deficit by 2009 summer. MAPP-U.S. utilities have committed to provide an additional 1,183 MW of capacity during this period. Most utilities in the Region propose to install natural gas-fired combustion turbines with short construction lead-time to meet capacity obligations.

In general, the MAPP transmission system is adequate to meet the needs of the member systems and will continue to meet reliability criteria through the planning period. Because of the tremendous increase in power marketing activity, however, the system is expected to continue to operate near its secure limit. Current studies at MAPP have also identified potential restrictions that may limit energy transfers from the Twin Cities (Minneapolis-St. Paul) area to Iowa and Wisconsin.

The Mid-Continent Area Power Pool (MAPP) Region has significantly increased its membership with the participation of three transmission-owning members in Kansas, two in Missouri, and three in Wisconsin. These members have joined the MAPP Reliability Council, Regional Transmission Committee, and Power and Energy Market, or all three. In addition, 26 new transmission-dependent companies have joined the MAPP Power and Energy Market and the MAPP Regional Transmission Committee, or both. MAPP membership now totals 105 members and includes 18 transmission-owning members, 59 transmission-using members, 75 Power and Energy Market members, 15 associate members, and eight regulatory participants.

MAPP Assessment Process

The MAPP Reliability Council and Regional Reliability Committee direct the annual assessment of adequacy and security through the Council's working group structure. The Transmission Reliability Assessment, Composite System Reliability, and Model Building Working Groups jointly prepare the MAPP ten-year Regional Reliability Assessment. The Reliability Studies, Design Review, and Operating Review Subcommittees are committed to reviewing MAPP reliability from near-term and long-term perspectives to ensure the MAPP system can meet the needs of its members.

Demand and Energy

The MAPP-U.S. and MAPP-Canada combined 1999 summer noncoincident peak demand was 36,263 MW, a 0.7% increase over 1998 (35,998 MW) and 2.5% below the 1999 forecast (37,196 MW). MAPP-U.S. accounted for 6.8% above 1998 actual demand and 2.4% below the 1999 forecast. MAPP-Canada was 11.1% above the 1998 actual demand and 0.4% above the 1999 forecast.

The MAPP-U.S. summer peak demand is expected to increase at an average rate of 1.6% per year during the 2000–2009 period, as compared to 1.8% predicted last year for the 1999–2008 period. The MAPP-U.S. 2009 noncoincident summer peak demand is projected at 36,999 MW. This projection is 0.7% below the 2008 noncoincident summer peak demand predicted last year.

Annual electric energy usage for MAPP-U.S. in 1999 (164,356 GWh) was 3.0% above 1998 consumption and 2.7% above the 1999 forecast.

Resource Assessment

Generating system adequacy for the MAPP-U.S. Region is judged to be inadequate over the 2000–2009 period. MAPP-Canada will be adequate over the ten-year period. Net capacity for MAPP-U.S. (committed and proposed generation additions, uprates, and retirements) will provide an additional 1,183 MW of capacity in the MAPP-U.S. area for 2000-2009. Committed and proposed capacity additions (new) account for 897 MW, uprates account for 301 MW, and retirements accounts for 15 MW. The summer reserve margin is expected to be below the 1999 forecast and to decline from a high of 17% in 2000 to 14% in 2002 and 6% in 2009 when committed and proposed generation is considered. The MAPP Agreement obligates the member systems to maintain reserve margins at or above 15%. In addition, when a 3% demand forecast uncertainty is taken into account, the MAPP-U.S. area may be capacity deficit by 2001 summer and nearly 5,300 MW deficit by 2009 summer.

Because of the potential generating system inadequacy, the Region must plan for additional resources and carefully watch construction lead times to ensure that enough resources will be available to maintain Regional adequacy. The ability to import power may be severely limited in the near term because of the lack of external resource availability.

Transmission Assessment

The existing transmission system within MAPP-U.S. is comprised of 7,239 miles of 230 kV, 5,742 miles of 345 kV, and 342 miles of 500 kV transmission lines. MAPP-U.S. members plan to add 342 miles of 345 kV and 201 miles of 230 kV transmission in the 2000–2009 time frame. The MAPP-Canada existing transmission system is comprised of 4,578 miles of 230 kV and 130 miles of 500 kV transmission lines. MAPP-Canada is planning for an additional 501 miles of 230 kV transmission in the 2000–2009 time frame.

MAPP member systems continue to plan for a reliable transmission system. Coordination of expansion plans in the Region takes place through joint model development and study by the Regional Transmission Committee. This committee includes transmission-owning members, transmission-dependent members, power marketers, and state regulatory bodies. The Transmission Planning Subcommittee, in cooperation with the five subregional planning groups, has prepared the MAPP Regional Plan, 1999 to 2008, to meet the needs of all stakeholders.

In general, the MAPP transmission system is judged to be adequate to meet firm obligations of the member systems provided that the local facility improvements identified in the ten-year transmission plan are implemented. Current studies at MAPP, however, have identified potential restrictions on the transmission system for outages of certain 345 kV lines in the Twin Cities metropolitan area of Minneapolis-St. Paul such as Prairie Island-Byron or King-Eau Claire. These outages may result in system stability restrictions that limit energy transfers from the Twin Cities to Iowa and Wisconsin.

MAPP has seen a tremendous increase in power marketing activity resulting from open access and available low cost energy in the Region. This high level of activity has stretched the existing transmission system to its reliability limits to take advantage of market opportunities. MAPP members will continue to take a proactive role in the planning and operation of the system in a secure and reliable manner.

Operations Assessment

The MAPP Security Center has been fully operational with the implementation of real-time system monitoring of key flowgates, data collection at five-minute intervals, and near real-time pre-contingency analyses of system conditions. MAPP member systems jointly perform interregional and intraregional seasonal operating studies under the direction of the Operating Review Subcommittee to coordinate real-time operations. Subregional operating review working groups have been formed to deal with day-to-day operational issues such as unit outages and schedules transmission system maintenance. The MAPP Reserve Sharing Pool continues to provide a benefit to the Region through the sharing of generation during system emergencies.

The Mid-Continent Area Power Pool (MAPP) membership includes 105 utility and nonutility systems. The MAPP Region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the provinces of Manitoba and Saskatchewan. The total geographic area is 900,000 square miles with a population of 18 million.

NPCC

NPCC faces the charge of ensuring adequate capacity as the industry transforms itself. Currently under study in New York and New England are over 5,400 MW and 20,000 MW of merchant plant activity to be in service by the end of 2002. The near-term challenge is to ensure the timely integration of this expected capacity and to fully integrate this new generation into the network.

NPCC Assessment Process

The NPCC Reliability Assessment Program brings together the efforts of the Council, its member systems, and the NPCC Control Areas in the assessment of the reliability of the bulk power system. Over the years, NPCC has developed an extensive set of Criteria, Guides, and Procedures (NPCC Documents) that define reliable operation and planning within NPCC, and with which compliance is mandatory on the part of all NPCC members. The Reliability Assessment Program requires that all NPCC documents are reviewed on a periodic basis to ensure that they remain current and timely in their focus. As part of the Program, the Task Force on Coordination of Planning is charged with conducting reviews of resource adequacy of each area of NPCC on an ongoing basis. In a similar manner, the Task Force on System Studies is charged with conducting periodic reviews of the reliability of the planned bulk power transmission systems of each area of NPCC and the transmission interconnections to other areas.

The primary objective of the NPCC area reviews is to identify those instances in which a failure to comply with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2), or other NPCC Criteria, could result in adverse consequences to another NPCC area or areas. If, in the course of the study, such problems of an inter-area nature are determined, NPCC informs the affected systems and areas and monitors the resolution of the possible threat to reliability.

Through the establishment of the Compliance Monitoring and Assessment Subcommittee, the NPCC Reliability Assessment Program has been enhanced to ensure that NPCC will comply with the NERC Planning Standards and Operating Policies as well as the NPCC Criteria. NPCC is also completing a comprehensive review and restructure of its operating Criteria and Guides to better align the NPCC and NERC documents, appending the NPCC-specific portions of its Criteria and Guides to the Standards and Requirements of the corresponding NERC Operating Policy, creating an augmented, composite NPCC-NERC document.

Demand and Energy

The average annual growth rate forecast for the summer peaking United States entities of NPCC for 2000 through 2009 is 1.2%, a slight decline from the 1999 forecast of 1.4%; projected annual electrical energy growth rate is 1.2% as compared with the projection of 1.5% for 1999. The average annual growth rate for the winter-peaking demand for the Canadian members of NPCC is 1.1%, as compared to last year's 1.2% forecast. The projected annual electrical energy growth rate is 1.2%, as compared with a growth rate of 1.3% projected in 1999.

Resource Assessment

New England

New England will meet the NPCC Resource Adequacy Criterion of one day in ten years loss-of-load-expectation (LOLE) for the period 2000 through 2009, inclusive, if future generating capacity additions are fully integrated into the New England transmission system. If partial integration is assumed, and a 50% derating of these new generating resources is modeled to reflect transmission constraints, New England system reliability could be below the one day in ten years LOLE criterion by the year 2006. New England also projects adequate resources to meet its reliability criterion through 2005, assuming a high load growth scenario. Beyond 2005, contingency plans will be called upon should this occur.

New York

New York will meet the NPCC criterion of one day in ten years loss-of-load-expectation (LOLE) through the 2002 period, at which point undetermined market solutions must be obtained, including over 5,000 MW of proposed merchant activity.

Ontario

Ontario is forecasting adequate levels of resources throughout the reporting period to meet the NPCC adequacy criterion, with four previously laid up nuclear units anticipated for a return to service in the 2002 to 2003 time period.

Québec

For the near term, Québec projects adequate reserves to comply with the NPCC LOLE criterion of one day / ten years for the near term. Beyond 2005, over 2,500 MW of uncommitted hydroelectric capacity continues to be studied.

Maritime Area (New Brunswick, Nova Scotia, and Prince Edward Island)

The reserve criterion for the Maritime Area is 20%, and adherence to this criterion demonstrates compliance with the NPCC reliability criterion. As a result of the Sable gas fields, the Maritimes Area of NPCC now projects increasing usage of natural gas for electricity generation during the 2000–2009 period.

Transmission Assessment

The existing interconnected bulk electric transmission systems in New England, New York, Ontario, Québec, New Brunswick, and Nova Scotia meet NPCC Criteria and are expected to continue to do so throughout the forecast period. In the U.S. areas of NPCC, planned transmission additions for voltage levels 230 kV and above total 333 miles, all in New England. In Canada, planned transmission line additions during the ten-year forecast period for voltage levels 230 kV and above total 343 miles in Québec and 25 miles in Ontario.

A key project currently planned in NPCC will reduce the number of calls for NERC transmission loading relief (TLR) procedures. Ontario Hydro and Detroit Edison are in the process of enhancing the transmission facilities on the Michigan-Ontario interface. Additional transformation and total phase-shifter control of the interface will be achieved by adding phase-angle regulating transformers to the Scott-Bunce 120 kV circuit and the two Lambton-St Clair 345 kV circuits. Together with the existing phase-angle regulator transformer in the Keith-Waterman 230 kV circuit, these enhancements will result in full PAR control of the interface, permitting the distribution of power flows over the individual interconnections to nearly match their ratings and increasing the thermal capability of the Michigan-Ontario interface by almost 400 MW. The phase shifter for Circuit L4D (Lambton-St. Clair 345 kV) remains in the manufacturing process and will not be operational until late in the autumn of the year 2000 at the earliest.

To further the coordination of interregional transmission assessment, NPCC is a party to Inter-Area Coordination Agreements with MAAC and ECAR. Through these and a similar agreement among MAAC, ECAR, and the Virginia-Carolinas (VACAR) Subregion of SERC, studies are regularly conducted among MAAC-ECAR-NPCC (MEN), VACAR-ECAR-MAAC (VEM). All are performed under the auspices of the Joint Interregional Review Committee, composed of representatives from ECAR, MAAC, NPCC, and VACAR.

Operations Assessment

Reliable operations within NPCC are achieved through a hierarchical system. Criteria, guides, and procedures developed at the NPCC level are expanded and implemented at the area level by the three Canadian control areas, the New York ISO, and the ISO New England Inc. The criteria establish the fundamental principles of interconnected operations among the areas. Specific operating guidelines and procedures provide the system operator with detailed instructions to deal with such situations as depletion of operating reserve, capacity shortfalls, line loading relief, declining voltage, light load conditions, the consequences of a solar magnetic disturbance, measures to contain the spread of an emergency, and restoration of the system following its loss. Coordination in the daily operation of the bulk electric system is achieved through recognized principles of good electric system operation, communications, and mutual assistance during an emergency.

TransÉnergie, the New York ISO, the Independent Electricity Market Operator (Ontario), and the ISO New England Inc. serve as the security coordination centers for NPCC. As such, each will exchange necessary security data through the Interregional Security Network (ISN). Further, NPCC routinely conducts weekly operational planning calls between control area operators to coordinate short-term system operations. NPCC establishes procedures for the exchange of security information discussed in these regularly scheduled, prearranged conference calls. The NPCC emergency conference call mechanism is a tool that augments the regular conference call process to enable operational security entities in NPCC and neighboring Regions to communicate current operating conditions and facilitate the procurement of assistance under emergency conditions. These calls may be initiated upon the request of any NPCC control area system operator and are coordinated by NPCC Staff. NPCC has also established a Memorandum of Understanding on Area Emergency Assistance to facilitate area response to either a forecast or actual shortage of operating reserves. Through this Memorandum of Understanding, coordination will be assured with neighboring areas, and clear and efficient communications with participants in all Regional markets will be established. The objective of the process is to maximize reliance on the marketplace to provide emergency support, thereby minimizing the need for emergency transactions between the control areas.

Ontario and New York, together with other Lake Erie companies, participate in the Lake Erie Emergency Redispatch (LEER) procedure. The objective of this procedure is to facilitate emergency redispatch among participants within the Lake Erie control areas to relieve transmission constraints that could otherwise result in the requirement of another Lake Erie company to shed firm load. LEER is implemented only when firm load curtailment is imminent. The LEER procedure was originally approved by FERC on May 12, 1999, and the Lake Erie Security Process Working Group continues to refine the security tools used to activate the LEER procedure to ensure they continue to meet the needs of the Lake Erie system operators.

NPCC is a voluntary, non-profit organization. Its current membership, of which there are 40, represents Transmission Providers, Transmission Customers, and ISOs serving the northeastern United States and central and eastern Canada. Included in the Membership Agreement are nonvoting memberships extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America as well as public interest organizations expressing interest in the reliability of electric service in the Region. The geographic area covered by NPCC, approximately one million square miles, includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia.

SERC

Assessment Process

The Reliability Review Subcommittee (RRS) of the Southeastern Electric Reliability Council-Engineering Committee (SERC-EC) annually assesses and reports on the adequacy of reliability studies conducted by the four subregions of SERC. The RRS also assesses the coordination of such studies with other affected subregions or Regions, and the ability of the planned systems to meet SERC and NERC reliability criteria.

The RRS evaluates adequacy and security for a ten-year period based on the SERC "Principles and Guides for Reliability in System Planning." Data for this analysis is provided to SERC by the individual member systems.

The RRS maintains a listing of reliability studies; recommends new reliability studies deemed necessary; reviews SERC reliability criteria (along with the SERC Planning Standards Working Group); acts as liaison between SERC-EC and other groups within SERC and NERC; and serves as a clearinghouse for the exchange of information.

In June 2000, the RRS completed its 21st annual review of subregional expansion plans and the process of coordination of planning among the SERC subregions and between SERC and adjacent Regions.

Demand and Energy

The SERC 1999 summer peak demand of 149,012 MW represented a 4.6% increase from the 1998 summer peak of 142,506 MW, and was around 1% higher than forecast. The 2000–2009 forecast of average annual growth in summer peak demand is relatively unchanged from the previous forecast, now projected at 2.36% growth.

Annual electric energy usage in 1999 was 768.4 Billion kWh, which was 2.8% greater than the 747.7 BKWh of electric energy usage in 1998. The forecast growth rate in energy usage is 2.4%. The historical SERC growth rate (excluding the Entergy subregion) for the last ten years is 2.92%.

Resource Assessment

Planned resources are judged to be adequate to meet forecast annual summer peak demand growth for the 2000–2009 period. Net capacity additions within SERC for the ten-year period total approximately 34,000 MW. These additions include combustion turbine units (40%), combined cycle (44%), and unspecified other (15%).

The overall SERC capacity resource margin for the ten-year period is 10–11.6% with a drop to 9.6% in the last year. Approximately 35% of the planned capacity additions in the next ten years are uncommitted, undefined resources.

In SERC, as in many other Regions of the country, significant amounts of merchant power plant capability are expected to be built within the next ten years. Almost 5,000 MW of capacity has been announced with the expectation of completion over the next year. Based on a survey by EPSA, roughly 20,000 MW of merchant capacity is in various stages of development targeted for completion by the end of 2003. Of course, the amount of that capacity which will actually be built is highly dependent on factors such as market prices over the next few years; ability to arrange suitable interconnection and transmission access agreements; the number of other merchant plants that are being constructed; ability of the company to obtain financial backing; and other typical business factors. In the long term, those same factors will help to set the tone for development in SERC or other Regions. While a portion of this new capacity consists of modifications that create additional megawatts of capacity at pumped storage, nuclear, and hydro facilities, the SERC Region is relying heavily on peaking capacity that must be contracted for, planned, and constructed in a short but manageable time period.

Based on its review of the 2000–2009 period, SERC's committed capacity margins appear adequate for the Region in view of the significant commitment by member systems to short lead-time resources. The Region and its member systems must continue to carefully monitor this capacity lead-time to ensure that proper resource development is pursued to maintain Regional reliability.

Transmission Assessment

The existing bulk transmission system within SERC is comprised of 20,558 miles of 230 kV, 753 miles of 345 kV transmission lines, and 9,230 miles of 500 kV transmission lines. SERC Systems plan to add 1,829 miles of 230 kV and 268 miles of 500 kV lines in the 2000–2009 period.

SERC member systems continue to plan for a reliable bulk transmission system. Coordination of transmission expansion plans in the Region is maintained by joint modeling efforts among member systems. The ability to transfer power above contractually committed uses both intra- and inter-regionally, has become marginal on some interfaces under both studied and actual operating conditions. This is a reliability concern because it impacts the geographic diversity of external resources that can be called upon during emergency import scenarios that may result from large unit outages.

The increase in bulk power marketing activity resulting from the transmission open access tariffs continues to push the operating state of the transmission system into conditions for which it was not originally planned. SERC member systems need to take a proactive role in advocating the continued planning and operation of the system in a manner that meets NERC and SERC reliability criteria.

Operations Assessment

SERC has implemented several measures in the last few years to ensure reliability of the system. There are five Security Coordinators in SERC — one in each of the Entergy, Southern, and TVA Subregions, and two in the Virginia-Carolinas Subregion. In addition, line loading relief procedures have been implemented since the summer of 1997. The SERC ATC Working Group has continued to refine the SERC ATC procedures to improve the overall process and to comply with the NERC requirements.

SERC member systems jointly perform seasonal operating studies and coordinate operations. The establishment of Security Coordinators and the sharing of real-time information have provided significant reliability benefits for operating the system.

Southeastern Electric Reliability Council (SERC) membership includes 37 members and 30 associate members. The Region, represented by the Council, is located in 13 states in the Southeastern United States, and covers an area of approximately 464,000 square miles. SERC is divided geographically into four diverse subregions that are identified as Southern, Tennessee Valley Authority (TVA), the Virginia-Carolina Area (VACAR), and Entergy.

SPP

SPP will have adequate generation capacity over the short term. Beyond the short term, meeting the target margins will be highly dependent on the ability of the market to provide the necessary generation resources.

The bulk transmission system is adequate for at least one year. Beyond that point, it is somewhat difficult to assess the bulk transmission system because of the large number of proposed merchant power plant additions in and around SPP. The bulk transmission study performed recently showed marginally adequate transmission to handle expanded growth in the Region. Should merchant power plant development continue, transmission would not be adequate to handle extensive exports required to deliver the new power to other markets outside SPP. SPP has already found that insufficient lead time exists to add transmission facilities to accommodate some of the generation additions and transmission requests planned for the short term.

Regional Transmission Organization

SPP, under a collaborative effort, will submit a filing to become a FERC-recognized Regional Transmission Organization (RTO) pursuant to their Order No. 2000 and order on SPP's initial filing. SPP will be responsible for Regional planning in coordination with affected transmission owners and other Members. This includes authority to direct transmission owners to construct transmission facilities in accordance with coordinated planning criteria, or, if necessary, under SPP's Tariff. Such planning must conform to SPP's own reliability requirements as well as those of NERC and each transmission owner, and with all applicable requirements of federal or state regulatory authorities. Together with SPP's market-based congestion management/pricing mechanism, such transmission planning and expansion responsibility enables SPP to administer efficient and reliable transmission service in coordination with state and regional authorities consistent with the RTO Final Rule.

State Restructuring for Retail Access

Four of the eight states within the SPP Region have current state legislation mandating retail open access. Arkansas, Oklahoma, New Mexico, and Texas have retail open access mandated to begin as early as June 1, 2001 (pilot project for Texas). New Mexico has delayed retail open access until January 1, 2002, which coincides with full retail open access for Arkansas and Texas. Oklahoma retail open access will occur July 2002.

The existence and participation of an RTO in market operations is anticipated in the Arkansas and Texas legislation. Generally, the generation portion of traditional utility operations will be deregulated and be available for the electric service provider to procure for delivery to end-use customers. The impact of retail open access on inter-control area scheduling and tagging from deregulated generation and electric service provider procurement activities has not been determined, but it is anticipated to increase. Reliability is a major consideration toward development of the retail access processes.

Assessment Process

The SPP Reliability Assessment Working Group (RAWG) reports directly to the SPP Board of Directors in an "auditor" role. The RAWG reviews (and summarizes in SPP's Annual Report) the many detailed studies performed by SPP organization groups throughout the year. The RAWG tracks and documents SPP bulk electric system reliability and highlights areas that, if unsuccessfully managed, will threaten service continuity.

Additionally, RAWG reviews member projections of demand, capability, and capacity margin. RAWG analyzes how future resource needs are planned and met such as through committed versus uncommitted new capacity, unknown or undermined capacity, units returned to service, and demand-side management. Furthermore, RAWG reviews loss-of-load-expectation (LOLE) analyses performed by another SPP working group as well as studies performed by the Transmission Assessment Working Group (TAWG).

Demand and Energy

SPP is a summer-peaking Region with projected annual peak demand and energy growth rates of 2.2% and 2.3%, respectively, over the next ten years. Members continue to forecast similar growth of future demand and energy requirements compared to previous years. These growth rates are consistent with the ten-year historical growth rates of SPP.

Members are focusing more on the short term (two to five years), thereby shrinking the planning horizon. This reduces the need for long-term (five to ten years) forecast accuracy. The projected growth rates for peak demand and energy over the next five years are 2.1% and 2.2%, respectively. The actual growth rates for peak demand and energy over the last five years were 2.5% and 1.8%, respectively.

Resource Assessment

The SPP reliability criterion requires members to maintain at a minimum a 12% capacity margin. Expected capacity margins reflected in EIA-411 data are 14.6% in 2001, 14.4% in 2002, and 13.8% in 2003. The capacity margins have a steady decline after 2003 down to as low as 10.3%.

Excluding from the EIA-411 information uncommitted purchases, sales and capacity additions and including only very certain capacity additions, the expected capacity margins are 13.7% in 2001, 12.7% in 2002, and 11.4% in 2003.

Regarding capacity margins beyond 2003, SPP members, for the most part, are assuming that the market will provide needed resources or that new, presently uncommitted capacity sources could be made available by those members within a two- or three-year time period.

Current merchant plant activity is high and in stark contrast to the almost non-existent activity only two years ago. Many of the proposed plants are completing permitting and starting construction. The forecast for available merchant plant additions to assist in maintaining the required capacity margin is very good.

The EIA-411 information does not reflect 7,735 MW of merchant plant additions being planned for the 2000 to 2003 time period. These planned additions, by year, are 1,852 MW in 2000, 2,611 MW in 2001, 2,172 MW in 2002, and 1,100 MW in 2003.

These merchant plant additions would significantly increase the above-mentioned capacity margins. This increase is approximately 1.7 percentage points for each 1,000 MW of the merchant plant capacity that is added. For example, if all of these merchant additions were made as planned, capacity margins for the 2001–2003 period would be between 21 and 24%. In addition, only a small percentage of the planned merchant capacity would need to be added in order to increase the above stated 11.4% capacity margin for 2003 to the 12% minimum required capacity margin.

As explained in the preface above and the "Transmission Assessment" section below, there may not be sufficient lead time to install the transmission facilities required to accommodate the addition of some of the planned merchant capacity.

Though SPP has never experienced loss of firm customer demand due to a capacity shortage, lower margins may challenge this trend in the future. Generation reliability assessment is becoming very difficult in the increasingly competitive market place. While economic theory states that the market place will meet demands, system operators have had frequent difficulty finding access to resources, regardless of price, in the past several years.

Transmission Assessment

Only a few transmission facility additions of regional significance are planned for the bulk transmission system over the next ten years. The additions being planned mainly benefit local areas and have minor impact on subregional or regional transfer capability. The planned transmission facilities of Regional significance include:

- 345 kV interconnection between the northern and western subregions of SPP in 2001, which will increase the transfer capacity between these subregions as well as between SPP and MAPP,

- 200 MW HVDC interconnection between SPP and WSCC in 2004, and
- Substantial additional transfer capacity within the west-central subregion of SPP in 2006.

For the purposes of OASIS posting of Available Transfer Capability (ATC), transfer capability studies are performed monthly on the bulk transmission system based on a sliding 16-month window. These calculations determine the most restrictive credible contingencies as recognized by each member company and/or the Regional transmission provider.

The bulk transmission system is shown to meet applicable NERC and Regional planning standards for this sliding study window. In addition to the 16-month sliding ATC studies, coordinated sub-regional assessments were performed for the 2000 summer peak, 2000/01 winter peak and 2004 summer peak seasons to assess system performance based on applicable planning standards. This series of coordinated sub-regional analyses indicate limitations of the bulk transmission system in the south Louisiana area for imports and Kansas for exports.

Regional generation interconnection procedures have been developed and approved by FERC. These procedures address the issues of lead time for adding transmission to accommodate new generation and also the needs of the merchant developers regarding transmission planning studies to determine the transmission additions needed to tie their planned generating plants into the bulk transmission system. In some cases where extreme amounts of transmission additions are required to serve the total planned capacity of new generation, other alternatives may be needed to meet the needs of both the transmission provider and the merchant developer.

In addition to providing merchant developers with an orderly means of approaching a transmission owner, consistent methodology and Regional requirements will enhance the transmission analysis to ensure Regional transmission reliability.

Operations Assessment

SPP has operated a security center since 1997 and is the Regional Security Coordinator. The security center, located at the SPP offices, provides the exchange of near real-time operating information and around-the-clock security coordination.

SPP operates under the NERC Operating Policies for Transmission Loading Relief (TLR). These procedures include daily preemptive screening to help members recognize heavy line loading. A major tenet of these procedures is to ensure that transmission congestion is alleviated by real changes in generation patterns, not a mere shuffling of interchange schedules. SPP has invoked TLR on its transmission facilities in recent years and expects that it will continue in the future.

Compliance Enforcement

The SPP Compliance Working Group has responsibility for ensuring compliance to NERC Standards and SPP Criteria. SPP maintains staff dedicated to the compliance monitoring and enforcement process within the Region. Work is done primarily though a working group structure. These various working groups have specifically assigned responsibilities. The SPP compliance staff monitors progress on a continuous basis and provides reports to NERC. Several SPP members are currently performing voluntary compliance audits through an independent auditor in compliance with NERC standards.

SPP has 54 members serving all or parts of Arkansas, Louisiana, Mississippi, Missouri, Kansas, Oklahoma, Texas, and New Mexico. The Region monitors, coordinates, promotes, and communicates information on the reliability of the electricity supply systems through the dedicated efforts of more than 370 people from member systems. The Board of Directors has responsibility for overall policy direction, and an administrative and technical staff located in Little Rock, Arkansas provides day-to-day coordination.

WSCC

Transmission system reliability is expected to be adequate throughout the ten-year period based on the annual study report and ongoing seasonal operating transfer capability assessments of major interties.

Projected resource capacity is expected to be adequate for the assessment period throughout WSCC.

Western Systems Coordinating Council's (WSCC) outlook regarding the reliability of the interconnected electric system in the West is presented below for each of the four subregions that comprise the Western Interconnection — Northwest Power Pool Area, Rocky Mountain Power Area, Arizona-New Mexico-Southern Nevada Power Area, and California-Mexico Power Area.

The projected capacity margins and fuel supplies are anticipated to be adequate to ensure reliable operation in all areas of the Region. The capacity margin adequacy over the next ten years assumes the timely construction of approximately 30,200 MW of net new generation. The capacity margin adequacy also assumes average weather conditions. If multiple areas peak simultaneously, portions of the Region may need to issue public appeals for customers to reduce their electricity consumption, and other measures may be instituted as necessary to ensure that adequate operating reserves are maintained. The transmission system is considered adequate for firm and most economy energy transfers. WSCC member systems and other organizations routinely identify and study options for addressing generation capacity adequacy and transmission adequacy under various scenarios, including adverse weather conditions. Concerns identified in such studies may appear to conflict with information presented in the WSCC section of this report. The WSCC narrative addresses adverse weather conditions but the data presented is based on average weather conditions and, therefore, may not be comparable with data used by others for their study scenarios.

Under WSCC's Regional Security Plan, three security centers have been established for the Region. The security center coordinators are charged with actively monitoring, on a real-time basis, interconnected system conditions to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur.

In the following text, several issues are mentioned that could pose significant challenges to the preservation of reliability in the Region to varying degrees:

- competition and increasing pressures to reduce costs,
- changes in the structure of the electric industry, and
- uncertainty regarding demand growth projections and the planning and installation of new generation.

Through active participation in WSCC and NERC, individual member participants will be able to manage these issues and maintain a balance between reliability and the economic pressures of competition. WSCC provides an open forum for all entities that have a stake in the planning and operation of the interconnected electric system in western North America, enabling them to actively share in the responsibility of maintaining this essential balance.

WSCC Assessment Process

The evaluation of reliability within the WSCC Region is performed using a comprehensive annual assessment process based on the following established reliability criteria:

- Power Supply Design Criteria,
- Minimum Operating Reliability Criteria, and
- Reliability Criteria for Transmission System Planning.

Adherence to these criteria provides an objective and deterministic evaluation of the reliability (adequacy and security) of the western interconnected system.

Resource Assessment

The resource assessment process in WSCC has been in place for many years and is prepared for the four subregions of WSCC. A resource assessment on a Region-wide basis is not appropriate because of transmission constraints.

Resource adequacy is assessed by comparing the sum of the individual member reserve requirements (determined by criteria) for a subregion with the projected reserve capacity. WSCC is currently refining its resource adequacy assessment practice in light of the changing electric industry.

At present, the projected reserve capacity (margin) is determined by subtracting the firm peak demand, exclusive of interruptible and controllable load management peak demand, from the net generation and firm transfers. Net generation and firm transfers are determined exclusive of inoperable capacity. If the projected reserve capacity margin exceeds the reserve requirement, it is expected that projected resources are adequate for the subregion. On this basis, projected reserve capacity is expected to be adequate throughout the WSCC Region for the 2000 through 2009 ten-year period. The assessment assumes that approximately 30,200 MW of net new generation will be built when and where needed. WSCC's enhanced assessment methodology will place additional emphasis on transmission limitations between assessment areas within WSCC.

Transmission Assessment

The member systems' transmission facilities are planned in accordance with the "WSCC Reliability Criteria for Transmission System Planning," which establishes performance levels intended to limit the adverse effects of each member's system operation on others and recommends that each member system provide sufficient transmission capability to serve its customers, to accommodate planned inter-area power transfers, and to meet its transmission obligation to others.

Each year WSCC prepares a transmission study report that provides an ongoing reliability-security assessment of the WSCC interconnected system in its existing state and for system configurations planned through the next ten years. The disturbance simulation study results are examined relative to the "WSCC Reliability Criteria for Transmission System Planning." If study results do not meet the expected performance level established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include: a southern island load tripping plan, a coordinated off-nominal frequency load shedding and restoration plan, measures to maintain voltage stability, a comprehensive generator testing program, enhancements to the processes for conducting system studies, and a reliability management system (described in more detail below).

WSCC established a process used to verify compliance with established criteria. The process is summarized below, along with the key components to be monitored in this process:

- Compliance Monitoring — A voluntary peer review process through which every operating member is reviewed at regular intervals to assess compliance with WSCC and NERC operating criteria. Control areas are reviewed once every three years.
- Annual Study Report — In accordance with WSCC policy, the system will not be operated under system conditions that are more critical than the most critical conditions studied. Security assessment shall be an integral part of planning, rating, and transfer capability studies.
- Project Review and Rating Process — Study groups are formed to ensure project path ratings comply with all established reliability criteria.
- Operating Transfer Capability Policy Group Process — Operating studies are reviewed to ensure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures. Four subregional study groups prepare seasonal transfer capability studies for all major paths in a coordinated subregional approach for submission to WSCC's Operating Transfer Capability Policy Group.

Reliability Management System

WSCC officially implemented Phase 1 of its Reliability Management System (RMS) on September 1, 1999 after a 19-month evaluation period. WSCC's RMS program is a first-of-a-kind sanction-based program to maintain reliability, and represents a significant milestone for the WSCC members and the electric industry.

The program, developed voluntarily through a public open process involving the WSCC membership, the regulatory community, and other interested stakeholders, provides for the enforcement of sanctions for noncompliance through contracts that are signed by WSCC and each RMS participant. WSCC was granted a Declaratory Order by the Federal Energy Regulatory Commission (FERC) and received a Business Review Letter from the Department of Justice enabling WSCC to proceed with RMS implementation in early 1999. FERC issued an order on July 29, 1999 accepting the RMS contracts. Thirty WSCC members, representing a substantial number of the WSCC control areas, have signed the RMS agreements.

Phase 1 of RMS requires compliance with the following criteria:

- control performance,
- operating reserve and operating transfer capability,
- disturbance control, and
- generating unit automatic voltage regulators and power system stabilizers.

The control performance standards, operating reserve, and operating transfer capability requirements are assessed monthly and the disturbance control standard and requirements for power system stabilizers and automatic voltage regulators are assessed quarterly.

Phase 2 of the reliability management system is presently under evaluation and development. Phase 2 includes requirements for:

- availability of operating limits to system operators on major transmission paths,
- protective relay and remedial action scheme application certification, and
- protective relay and remedial action scheme misoperation.

On the basis of these ongoing activities, transmission system reliability of the Western Interconnection is projected to be adequate throughout the ten-year period.

Northwest Power Pool Area

The Northwest Power Pool (NWPP) Area is comprised of the states of Washington, Oregon, Idaho, and Utah; the Canadian provinces of British Columbia and Alberta; and portions of Montana, Wyoming, Nevada, and California. Over the period from 1999 through 2009, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 2.1 and 1.8%. Resource capacity margins for this winter peaking area range between 11.5 and 19.4% of firm peak demand for the next ten years.

The internal NWPP Area transmission capability is expected to permit anticipated transfers among NWPP systems under most conditions through 2009. Generation capacity in the NWPP area is also expected to be adequate over the same period to meet normal winter loads. Should very high peak demands occur during a low probability extreme cold weather period, the Pacific Northwest may need to rely on its capability to import power. During extreme cold weather periods, the import capability of the Pacific DC Intertie is expected to remain at 3,100 MW. However, studies show that the 3,675 MW import capability on the California to Oregon 500 kV AC Intertie may be limited to under 1,000 MW for these conditions. For this reason, emergency warning procedures are being developed for winter operation should extreme cold weather load levels occur. The purpose of the plan is to facilitate communications and encourage regional actions in advance of a potential emergency. The procedure will address progressive measures intended to compliment current regulations and policies, and to maintain load/generation balance involving control areas and load serving entities. Additionally, the procedures include stakeholder and public awareness communication plans.

The transmission interconnections between the province of British Columbia and the state of Washington have transfer capability restrictions that are adversely affected by transmission system conditions in the Puget Sound area. Utilities in the area are working together to identify ways to reduce these system transfer capability restrictions while continuing to meet reliability requirements. System reinforcements are being implemented to satisfy south to north firm transfer requirements and to facilitate increased north to south transfers under adverse operating conditions. Also, methods are being worked on to more effectively address internal transmission constraints that continue to occur in this area.

Agreement has been reached among Federal parties involved in operation of the Columbia River Basin concerning river operations for the next two years. These include the National Marine Fisheries Service, the U.S. Fish and Wildlife Service, the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers, and the Bonneville Power Administration (BPA). Agreements for future years will be based in part on experience during this period. The net impact of the present agreement is a slight reduction in generating capability as a result of hydro generation spill policies designed to favor migration of anadromous fish. The agreement includes provision for negotiating changes in the plan under emergency conditions.

BPA and eight investor-owned utilities are working together to prepare a filing for a regional transmission organization known as RTO West in the NWPP area. The filing for RTO West is to be submitted in two stages, the first in October 2000, and the second in the spring of 2001. If approved by FERC, the implementation could begin as early as summer of 2001.

Rocky Mountain Power Area

The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season due to variations in weather. Over the period from 1999 through 2009, peak demand and annual energy requirements are projected to grow at a 2.7% annual compound rate. Summer resource capacity margins range between 15.8% and 24.4% of firm peak demand for the next ten years.

New generation was installed in the RMPA in 1999 and 2000. Public Service Company of Colorado (PSC) built or purchased 414 MW of new generation in 1999, and the City of Colorado Springs added 73 MW. PSC is also purchasing or constructing 356 MW that will be on line by June 2000. A significant portion of that generation (111 MW) will be sited in the Denver/Boulder metro area so that voltage support from the units will be available to enhance area reliability. In addition, PSC plans to add 214 MW in 2001. Platte River Power Authority is adding 80 MW of generation in 2002. The new generation project includes a Rawhide-Timberline 230 kV line and upgrades to some existing 115 kV lines in the Fort Collins area to meet projected peak demand.

Tri-State Generation and Transmission Association, Inc. is constructing a major 230 kV line from Walsenburg, Colorado to Gladstone Substation in northeast New Mexico. The Pawnee-Story 230 kV line rebuild and a few other minor projects has allowed an increase in the transfer capability from southeast Wyoming to northeast Colorado from 1,424 MW to 1,509 MW. Studies have shown that locating new generation at Pawnee Station and returning a 230/155 kV autotransformer at Wray, Colorado to service may increase this transfer limit an additional 79 MW. In June 2001, PSC will finish construction of a major 230 kV transmission line from Fort St. Vrain to Green Valley Substation east of Denver to access 685 MW of power located at Fort St. Vrain. WestPlains Energy is installing a 100 MVA 230/115 kV autotransformer near Canon City in the third quarter of 2001. The autotransformer will improve voltages in that part of its system.

Hydroelectric generation is expected to be slightly below normal in the northern and central Rocky Mountains. Water inflows into the South Platte, North Platte, Colorado, Big Thompson, and Green Rivers are expected to be slightly below normal this year as snowpack is about 85% of normal in these river basins. Water inflows into the Missouri River are expected to be approximately 85% of normal this year. Reservoir storage is in good condition and hydroelectric generation is expected to be near the long-term average. The Glen Canyon power plant is operating under a summer seasonal test flow that is trying to emulate a historic river flow. The associated release limitations reduce peaking capability, but the plant will be able to respond to short-term emergency conditions.

Arizona-New Mexico-Southern Nevada Power Area

The Arizona-New Mexico-Southern Nevada Power Area consists of Arizona, most of New Mexico, the westernmost part of Texas, southern Nevada, and a portion of southeastern California. Over the period from 1999 through 2009, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 3.6 and 3.4%. Resource capacity margins for this summer peaking area range between 11.3 and 28.1% of firm peak demand for the next ten years.

A few transmission projects have been reported for the subregion that will increase transfer capability and improve reliability. These projects include a 115-mile 230 kV interconnection from Walsenburg Substation in southeastern Colorado to a new 230/115 kV substation at Gladstone, New Mexico. This line is scheduled to enter service in 2002. Another planned transmission project is a 230 kV line from the San Juan generating plant to the city of Farmington, New Mexico. It is scheduled to enter service in 2004. An additional 345 kV connection between generating facilities in northern New Mexico and a substation in central New Mexico is under investigation, with a possible in-service date of 2005.

Significant amounts of shunt capacitors and series compensation have been and are being installed in order to preserve reliability in the area. Several southwestern utilities are planning to either install combustion turbine generators or make purchases of peaking power from independent power producers.

The major generating plant operators in the area participate in the Southwest Reserve Sharing Group. This group shares contingency reserves, using a computer-assisted communication system for activating reserves in the form of emergency assistance to recover from generation outages in the area within the ten-minute recovery criteria.

In response to the restructuring of the electric utility industry, the Southwest utilities are investigating the feasibility of creating a regional transmission organization (RTO) to be called Desert STAR (Desert Southwest Transmission And Reliability Operator). The main goals of the RTO are to provide electrical system security and reliability in accordance with WSCC and NERC policies and to provide nondiscriminatory open access to the transmission system. The present timetable calls for operation of the Desert STAR RTO on December 15, 2001.

California-Mexico Power Area

The California-Mexico Power Area encompasses most of California and the northern portion of Baja California, Mexico. Restructuring of the electric industry in California has added much uncertainty to future adequacy projections of generating capacity, energy production by independent power producers, and effects of customer energy efficiency/demand-side management programs. Recognizing that future forecast uncertainty exist, peak demands and annual energy requirements are currently projected to grow at respective annual compound rates of 1.8 and 2.1% from 1999 through 2009. Projected resource capacity margins range between 9.3 and 17.8% of firm peak demand for the next ten years.

A severe heat wave in California in 1998 resulted in numerous curtailments of service to interruptible customers. The curtailments occurred in conjunction with the loss of nearly 2,000 MW of capacity due to forced outages at several power plants. In spite of a relatively cool summer in 1999, the California Independent System Operator (CISO) declared emergencies on occasions when spinning reserve levels could not be maintained at adequate levels due to high demand levels, limited generation resource availability, and reductions of transmission import capability into the state.

The California Independent System Operator (CISO) assumed operational control of the transmission grid of the three California investor-owned utilities on March 31, 1998. The CISO is responsible for several functions including: providing nondiscriminatory open access to the transmission grid, controlling dispatch and maintaining reliability of the transmission grid, and procuring and providing ancillary services.

The CISO is administering a coordinated planning process that forms the basis for planning future changes and additions to the transmission system. The process calls for stakeholder participation in the planning process with the intent to facilitate the development of projects that best meet the needs of all users while maximizing the potential benefits to California. Planning efforts are also taking place to meet the needs of the San Diego and Orange county areas by increasing the transfer capability south of the San Onofre generating station, and proposing a new 500 kV interconnection for the area.

Western Systems Coordinating Council (WSCC), with 84 members and 17 affiliate members, encompasses about 1.8 million square miles in 14 western states, two Canadian provinces, and a portion of Baja California Norte, Mexico. Extremes in population and demand densities, in addition to long distances between demand centers and electric generation sources, characterize the Region. The Region is subdivided into four areas: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydroelectric generation (65% of installed capacity); the Rocky Mountain Power Area, which can be either summer or winter peaking with a 24% hydroelectric and 59% coal-fired generating capacity mix; the Arizona-New Mexico-Southern Nevada Power Area, which is summer peaking with a 17% nuclear and 44% coal-fired generating capacity mix; and the California-Mexico Power Area, which is summer peaking and heavily dependent on gas-fired generating units (47% of installed capacity).

USEA

United States Energy Association

For more information, contact the USEA at 202.312.1230

(39)

United States Energy Association Releases "Toward a National Energy Strategy"

WASHINGTON, D.C., February 21, 2001 – The United States Energy Association (USEA) today released "Toward a National Energy Strategy" that makes recommendations in six major areas to assure that consumers can benefit from an increased supply of affordable energy resources that are available in a ready, reliable and environmentally responsible manner.

The USEA paper, "Toward a National Energy Strategy," was developed by a broad range of energy interests. It recommends six areas of action: enhance energy supplies; encourage energy efficiency and affordable prices; stimulate global energy trade and development; promote energy technology development and long-range research and development initiatives; balance energy use and environmental concerns; and unify the energy policy process.

On releasing the report, Richard Lawson, chairman of the USEA National Energy Policy Committee, said: "Such an energy policy must meet several challenges, including overly burdensome environmental regulations that prevent access to new energy sources; the adverse national security implications of rising oil imports; an energy delivery infrastructure that is aging and increasingly overwhelmed by growing demand; a regulatory process that is often unfair and counter-productive; and a lack of foresight in developing new, more efficient energy technologies and alternative energy sources."

"Economic efficiency, energy security, energy technology and regulation and incentives are the four core principles we believe a sound national energy strategy should be anchored by," said Barry Worthington, executive director, USEA.

Worthington explained that, in many markets, increased demand outstrips reliable supplies. Key industries are being deregulated and technology is advancing at an unprecedented rate. Environmental regulations have grown increasingly costly and complex and, moreover, consumers often express confusion at the array of energy choices now available. In addition, energy companies confront both greater competition and increasing regulatory uncertainty can heavily penalize those companies that expand production to meet the increased energy demands of our growing population and economy.

-more-

Industry groups involved in preparing the report were: American Gas Association, American Petroleum Institute, American Public Power Association, Edison Electric Institute, Electric Power Research Institute, National Mining Association, National Rural Electric Cooperative Association, and Nuclear Energy Institute.

For copies of "Toward a National Energy Strategy," please contact the USEA at 202.312.1230.

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The United States Energy Association (USEA) is the U.S. Member Committee of the World Energy Council (WEC). USEA is an association of public and private energy-related organizations, corporations, and government agencies. USEA represents the broad interests of the U.S. energy sector by increasing the understanding of energy issues, both domestically and internationally.

United States Energy Association

February 2001

Toward a National Energy Strategy

Policy Recommendations Summary

USEA

United States Energy Association

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DOE002-0435

United States Energy Association:

POLICY RECOMMENDATIONS SUMMARY

THE RECORD COLD WINTER and the resulting consumer reaction to rising energy prices, the critical energy shortages that have caused rolling blackouts in California, and the possibility that the situation in California could be duplicated elsewhere, have had one beneficial effect. They have made a diverse group of public and private interests — including policymakers from the president and the Congress on down — aware of the clear need for a national energy policy that will allow all energy providers to more effectively meet the ever growing energy demands of American families and businesses.

Such an energy policy must meet several challenges, including overly burdensome environmental regulations that prevent access to new energy sources; the adverse national security implications of rising oil imports; an energy delivery infrastructure that is aging and increasingly overwhelmed by growing demand; a regulatory process that is often unfair and counter productive; and a lack of foresight in developing new, more efficient energy technologies and alternative energy sources.

The members of the United States Energy Association (USEA) are united in our belief that the time has come to develop a national energy strategy that meets these challenges and also tackles head on the many other critical energy choices we must make. Therefore, we have outlined a strategy that will increase the supply of affordable energy and deliver it to the American consumer in a safe, reliable and environmentally responsible manner. This paper, which was developed after much debate by a broad range of energy interests, outlines that strategy. Specifically we recommend the following steps:

Enhance Energy Supplies

- The nation should encourage energy supply expansion with policies that fully recognize no single source can meet our growing energy needs.
- Current policies should be amended to allow environmentally sound access to domestic resources in order to reduce dependence on foreign supplies, and ensure that American consumers continue to have access to energy at reasonable, affordable prices.
- Tax reform should be enacted to spur capital investment in reliable, affordable and environmentally effective energy technologies and supporting infrastructure.

Encourage Energy Efficiency and Affordable Prices

- Governmental policies should promote energy efficiency.
- There should be free and competitive markets regarding pricing, technology deployment, energy efficiency, and selection of fuels and energy suppliers.
- Funding for the low-income home energy assistance program and weatherization program should be increased.

Stimulate Global Energy Trade and Development

- U.S. leadership in energy development, services and technology should be promoted on a global basis.
- Tax provisions that diminish the international competitiveness of U.S. multinational energy companies by exposing them to double taxation (i.e., the payment of tax on foreign source income to both the host country and the U.S.), and to restrictive anti-deferral rules, should be eliminated.
- Any U.S. foreign policy and development assistance should increase supplies of reliable, affordable and market-based energy for developing countries and countries in economic transition in a way that opens markets to U.S. goods and services, creates cooperative partnerships between the U.S. and overseas energy firms, and enhances international economic and political security.
- The U.S. should foster more open political, legal and institutional structures in developing and reforming countries that facilitate energy trade and investment.
- Federal policymakers should avoid unilateral trade and economic sanctions that exclude U.S. companies from key markets in which foreign-based companies are free to invest.

Promote Energy Technology Development and Long-Range R&D Initiatives.

- Investment in energy technology research and development should focus on energy sources that can realistically expect to have a significant impact in meeting U.S. energy needs over the next 20 to 30 years.

Balance Energy Use and Environmental Concerns

- Government-sponsored education programs should emphasize the importance of energy infrastructure and energy sources as essential to continued economic security and development.
- Government programs intended to advance environmental technologies should measure environmental performance and be available to any energy source that achieves environmental goals rather than favoring selective fuels or technologies.
- The safe and efficient movement of energy goods and services requires significant improvement of the U.S. transportation infrastructure.

Unify the Energy Policy Process

- Rulemaking should promote regulatory predictability to stabilize investment decisions.
- Comprehensive electric industry restructuring should promote efficient competition by encouraging flexible approaches to electricity markets and new investment in transmission and generation.

ABOUT USEA AND THE NES STUDY

The United States Energy Association (USEA) is the U.S. Member Committee of the World Energy Council (WEC). USEA is an association of public and private energy-related organizations, corporations, and government agencies. USEA represents the broad interests of the U.S. energy sector by increasing the understanding of energy issues, both domestically and internationally.

In conjunction with the U.S. Agency for International Development and the U.S. Department of Energy, USEA sponsors our nation's Energy Partnership Program.

USEA sponsors policy reports and conferences dealing with global and domestic energy issues as well as sponsors trade and educational exchange visits with other countries.

The USEA Board of Directors agreed that the year 2000 was an appropriate time to take an in depth look at United States energy policy. Previously the USEA had published 11 Annual Assessments of U.S. Energy Policy. The Board approved the USEA National Energy Strategy project under the leadership of Richard Lawson, Chairman of its National Energy Policy Committee. The project was directed by Guy Caruso. Informed by the results of workshops on key energy issues, a working group representing all sectors of the industry has prepared the following report.

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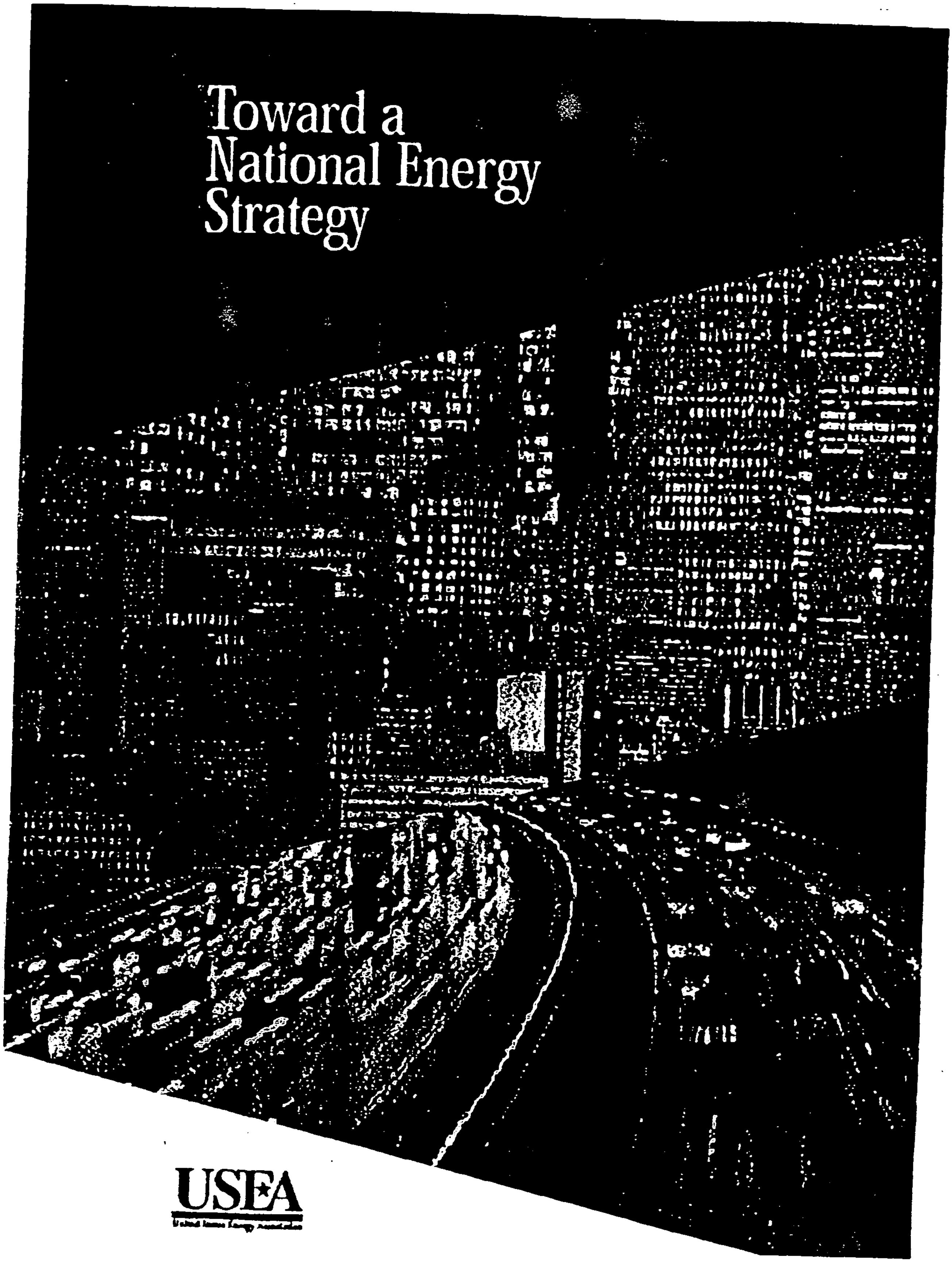
Toward a National Energy Strategy



USEA

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ABOUT USEA AND THE NES STUDY

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United States Energy Association

February 2001

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USEA
United States Energy Association

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ELEMENTS OF AN EFFECTIVE NATIONAL ENERGY STRATEGY

SETTING THE GOAL

Members of the United States Energy Association (USEA) believe that energy policymakers, regulators, consumers and producers face critical policy and investment choices in the decades ahead. In many markets increased demand outstrips reliable supplies. Key industries are being deregulated. Technology is advancing at an unprecedented rate. Environmental regulations have grown increasingly costly and complex. Consumers often express confusion at the array of energy choices now available. And energy companies confront both greater competition and unforgiving financial markets that can heavily penalize those companies that expand production to meet the increased energy demands of our growing population and economy.

The proper response to these uncertain times is the development and implementation of a sound National Energy Strategy (NES). USEA members propose that the objective of this strategy be the delivery to consumers—in a ready, reliable and environmentally responsible manner— of an increased supply of affordable energy resources and energy-related services from a broad range of energy providers.

CORE PRINCIPLES

USEA members believe that this National Energy Strategy should be anchored in four core principles:

- Economic efficiency. Economic efficiency is maximized when competitive markets guide decisions affecting global energy supply and demand. Moreover, given the inherent uncertaint of energy markets and of efforts to project future trends, a diversity of fuels strategy has proven moreefficient than picking "winners and losers" when addressing long-term energy problems.
- Energy security. Energy security is best achieved through diverse supplies of all forms of domestic and international ~~energy.~~ Similarly, contingency plans are needed to mitigate energy supplydisruptions, and these U.S. plans can be enhanced through international cooperation.
- Energy technology. Research and development can spur improvements in energy technologies that produce long-term cost-effective solutions to many environmental concerns. Research to address environmental problems and to expand energy choices is an appropriate and essential role for government. Partnerships between public and private sectors (domestic and international) can also speed this process.
- Regulation and incentives. Government officials can use regulation and incentives to ensure public health, safety and consumers rights. Decisions to use these policy tools should be based on sound science and realistic needs. Such decisions also should be timely, consistent and coordinated so that the benefits of responsible environmental protection are kept in balance with the benefits of energy use.

A national goal and these core principles alone, of course, are insufficient to build an effective National Energy Strategy. The principles must be applied to key policy issues, and input should be sought from those most affected by policy decisions. It is critical that the new Administration focus not only on the near-term issues that are in today's headlines, but also on long-term issues. The concern over potential climate change, attributed in part to fossil fuel combustion, could be a major factor in shaping future energy choices. It is critical that policymakers and energy producers look to 2050 and beyond in shaping our research and regulatory agendas, and that we consider the long-term implications of policies we adopt today. Other long-term issues, such as depletion of traditional energy resources and the need for developing technologies to find and produce non-traditional energy resources must also be contemplated in current policies. This long-term planning, conducted in an open process with non-governmental organizations (NGOs) and private sector participation, is an appropriate federal role. The following are policy issues which USEA members regard as critical to the development of a sound National Energy Strategy.

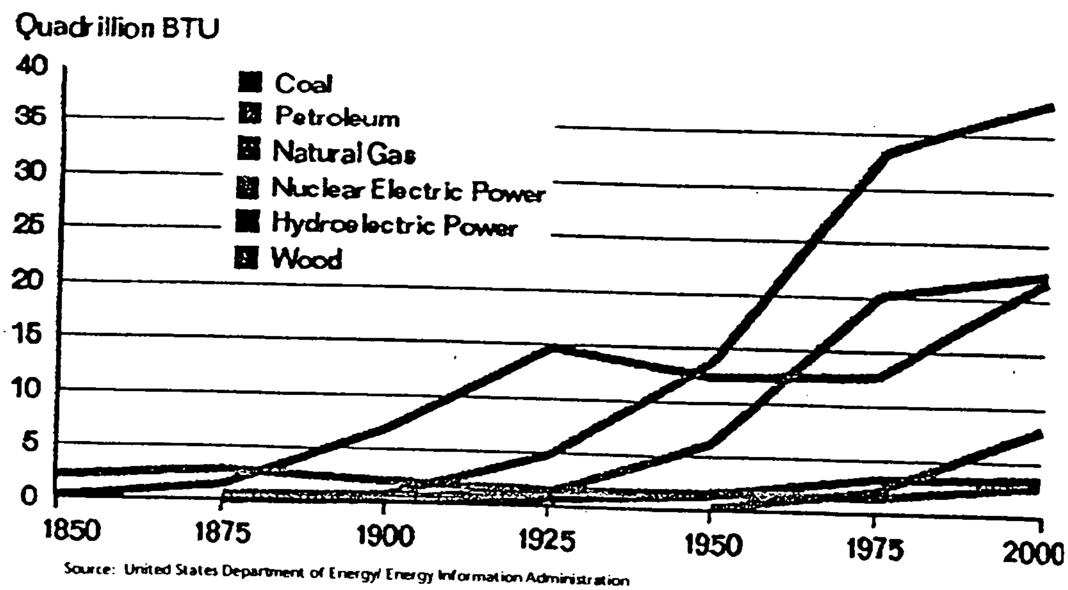
KEY ISSUES

Meeting U.S. Energy Requirements

The President and Congress can help energy producers and suppliers insure an adequate energy supply to support the nation's needs as we enter the 21st century. However, securing a reliable energy supply in the coming decades will require careful review of policy options and judicious action by policymakers and government officials at every level.

Careful deliberation is required because energy production and consumption is so inextricably tied both to economic growth and population growth. For example, the United States experienced a significant economic boom at the close of the 20th century, supported in part by a dramatic rise in consumption of affordable energy. However, this expansion of

Energy Consumption in the United States 1850 - 2000



Source: United States Department of Energy/ Energy Information Administration energy consumption occurred at a time when energy supplies, particularly in the electricity sector, barely expanded at all. Substantial reserve margins at the outset of the recent economic expansion made economic growth possible, but those margins have now been depleted. Electricity capacity and, more broadly, energy supply must be increased to support continued U.S. economic growth, even at a reduced annual rate.

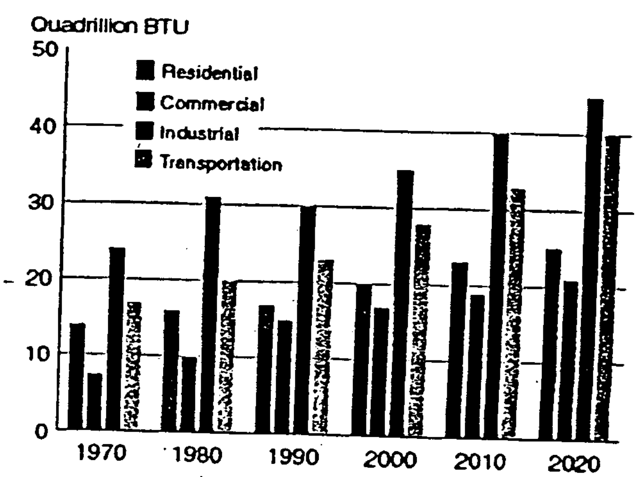
The Annual Energy Outlook 2001 Forecast

Energy policy must insure that supplies are adequate. The most recent Department of Energy/ Energy Information Administration Annual Energy Outlook 2001 (AEO) reveals that the demand for energy of all forms is likely to increase significantly over the next 20 years. By 2020, total energy consumption is forecasted to increase by 32 percent, petroleum by 33 percent, natural gas by 62 percent, coal by 22 percent, electricity by 45 percent and renewable energy by 26 percent. At the same time, energy efficiency is projected to improve by 1.6 percent per year. The forecasts in consumption are stunning. Not only has crude oil production fallen by 14 percent since its peak in 1970, natural gas production also has fallen by 14 percent since 1973 and has remained virtually flat for seven years. Moreover, refinery capacity has fallen by 11 percent since 1981 and one-half of refineries have been shutdown over the same period.

The AEO forecast implies that massive investments in infrastructure will be made to produce and deliver energy to American consumers. However, the record to date does not inspire confidence that the current regulatory structure will support these investments. For example, the AEO projects an increase in refinery capacity of 1.7 million barrels per day and an increase in refinery utilization from 93 to 95 percent. A new EPA interpretation of rules relating to the expansion of existing capacity raises considerable doubt that this capacity will be built. If the 1.7 million barrels per day requirement is to be met through new capacity additions, eight to ten new refineries would have to be built. A large-scale refinery has not been built in the U.S. in over 20 years. The forecast also calls for an increase in refined product imports of 3 million barrels per day. This raises the question: will there be sufficient foreign refinery capacity to meet our stringent fuel specifications—especially with increasing regulation?

Similarly, the forecast for oil and natural gas consumption implies the construction of major new petroleum products and natural gas pipelines. Other natural gas facilities and petroleum terminals and facilities will be needed to meet the increased demand. How are we going to do this given the daunting regulatory apparatus and the well entrenched "Not In My Back Yard" (NIMBY) culture? The answer is that we need to develop and implement an energy policy that focuses on adequacy of supply to meet the growing needs of consumers. The goal should be to provide reliable

U.S. Primary Energy Use



Source: DOE/EIA

and affordable supplies of energy to consumers. If it is not produced here, petroleum can be imported but most natural gas must be produced in North America because of very limited LNG import infrastructure. The AEO forecasts an increase in net oil import dependence from 55 to 64 percent during the next 20 years. This raises numerous questions about diversity of supply, national security concerns and the potential for increased price volatility.

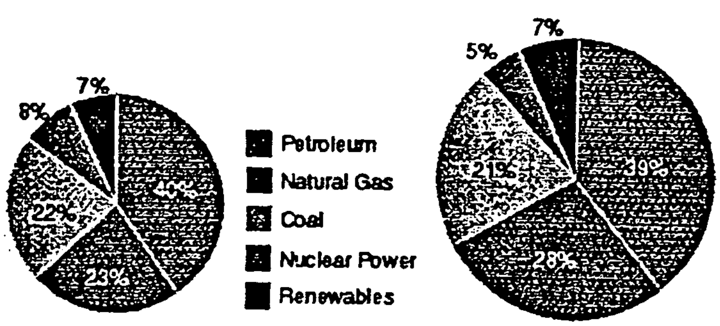
The current shortfall of reserve margins in electricity can be traced to a consistent pattern of demand growth exceeding expectations. Indeed, over the past decade almost all institutions engaged in predicting electricity demand growth have settled on the figure of an increase of about 1.5% annually. However, the actual growth rate has exceeded 2.0% annually. Recognizing this shortfall, the EIA's most recent forecast projects annual growth of 1.8% annually through the year 2020. By 2020, 393,000 MWs of new capacity will be required to meet demand growth and to offset capacity retirements. This is the equivalent of constructing approximately 40 new 500 megawatt power stations per year, over the next 20 years.

Closing this gap poses a major policy challenge. Moreover, policymakers face this challenge at a time when the national grid for electricity transmission is increasingly constrained and the ability to produce and deliver fuel to the generating facilities also is constrained. Furthermore, attracting investment and construction capital for infrastructure projects is growing increasingly difficult, as is permission to site new capacity, transmission and distribution facilities. In short, government intervention is required—in the form of an enlightened energy policy—in order to preserve economic growth, energy security and reasonable environmental protection.

Another major challenge is ensuring the reliability of the electricity transmission network, particularly at a time of increased market demand. Originally, transmission lines were used to deliver backup power and to economically exchange power among neighboring electric utilities. Today, market demand drives the use of the transmission system, and electricity is often "wheeled" great distances. Competition, in short, has turned local backup systems into a patchwork of interconnected electric super highways. This increased use has lead to concerns about congestion and reliability. Policymakers need to keep these new demands in mind and not create regulatory demands that compromise the transmission facilitates needed to carry power from where it is generated to where it is consumed.

Some have argued that America's energy problems can be resolved by increasing our reliance on solar, wind and energy efficiency measures. This report includes policy recommendations aimed at maintaining our diverse energy supplies. It also calls for more focused attention on energy research and development, and the continuation of efforts to develop solar, wind and efficiently applied technological initiatives that allow for market-based demand responses. However, the

Energy Demands to 2020



96.14 Quadrillion BTUs — 1999

127.03 Quadrillion BTUs — 2020

Source: DOE/EIA

principal focus of this report is on those energy resources and delivery systems that provide more than 98% of the nation's current energy supply. This is the appropriate focus for policymakers, too. Indeed, even if solar, wind, geothermal and efficiency measures quadrupled their contribution to the energy mix during the next 20 years, the dimensions of the energy supply issue described above remains essentially unchanged.

The evidence is everywhere that this nation faces a major energy supply challenge in the decades ahead. Failure to formulate effective policies to meet that challenge will likely compromise U.S. economic growth, energy security and social well-being.

Market-Based Energy Policies

The cornerstone of a sound National Energy Strategy is reliance on competitive markets to allocate energy supply and demand. This lesson is widely accepted and has proven, time and again, to be true. Of course markets are not perfect, particularly with respect to such externalities as energy security, public health and safety, and environmental protection.

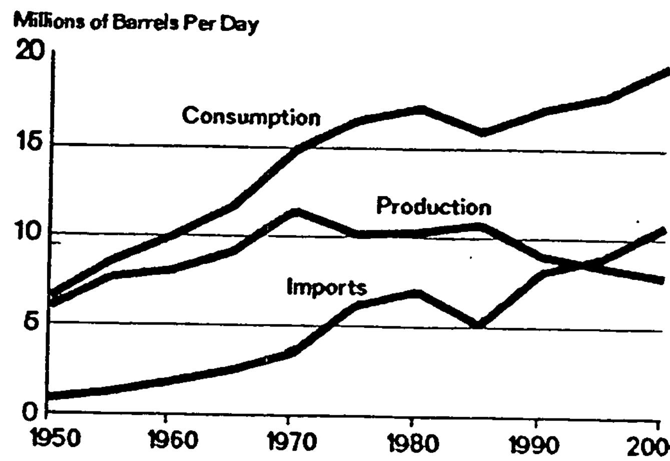
Here, government policy will continue to play an important role in the energy sector. However, government officials at all levels should not impose new regulations on the energy supply system—even in an attempt to address health, safety and environmental issues—unless those regulations are based on sound science and incorporate the most cost-effective options. Policymakers should also continue to substitute competition for regulation to achieve these same goals, whenever possible.

Security of Supply

The U.S. is the only major industrial nation that significantly limits access to its own energy resources. Because of these constraints, U.S. dependence on foreign energy supplies inevitably will increase over the next 20 years. Many of these constraints need to be reexamined. New technologies are regularly adopted for energy production, storage and delivery that address the very environmental or public safety concerns that originally led to constraints. These objections to energy development and production no longer may be relevant. As time and technologies change, so also should restrictive energy policies. Domestic energy resources, such as coal, petroleum, natural gas and uranium, must be made available for environmentally sound exploration and development.

Policymakers should also consider recent changes in the international arena. A disruption of U.S. energy supplies could cause signifi-

Petroleum Consumption, Production and Imports 1950- 1999



Source: DOE/EIA

cant damage to the U.S. economy. Terrorism, regional conflicts in energy exporting countries, industrial accidents and even acts of God require contingency plans and policies. A growing dependence on imported energy need not mean increased vulnerability to supply disruptions, provided effective emergency preparedness programs and policies are in place. Given the global nature of energy markets and the fact that the U.S. economy cannot be isolated from the risks of energy supply disruptions, contingency plans should include international cooperation as a key component.

Energy Efficiency

Investments in energy efficiency can reduce energy use and operating costs. The use of less energy can help protect the environment. When energy efficiency opportunities are identified, firms and individuals should take advantage of these opportunities. However, decisions that involve a trade-off between energy efficiency and energy production should be transparent. Such decisions also should not favor one option over the other, for the choice really involves a complementary relationship.

Indeed, when given appropriate competitive market signals, improved efficiency in energy production is as significant a priority as improved energy-efficiency among end users. In recent decades, improvements in technology and productivity have increased the efficiency of energy suppliers in all sectors. Policymakers should therefore allocate R&D energy efficiency funding on the basis of potential gain, regardless of whether that efficiency gain occurs during energy production or energy consumption.

Capital Investments

Enormous capital investments in all forms of energy—fossil fuels, nuclear energy and renewable energy—will be required to fuel the U.S. economy during the early decades of the 21st century. These investments will be needed in all phases of the energy sector, from production to generation to storage to transmission and distribution to improved end-use efficiency. A sound National Energy Strategy can help create the predictable operating and investment environment that all energy sectors require in order to thrive.

The regulatory process and tax policies are particularly important to attracting the requisite capital investment for growth in the energy sector, and the U.S. economy. Regulatory policies should be simple, durable and predictable, both at the national and local level. This is especially true of efforts to deregulate and restructure many U.S. energy markets. Such efforts are leading siting and transmission issues to become a matter of national policy. Federal policymakers should take these changes into account when reviewing energy laws and energy regulatory authorities. Tax policies should encourage investment for all forms of energy supply and infrastructure.

International Energy Trade and Development

Petroleum imports to the United States will likely increase for the next several decades, regardless of efforts to develop additional domestic energy resources. This reality, plus the continued globalization of the energy economy, will force U.S. policymakers to address international trade and development issues. Indeed, the future well-being of Americans and citizens of other countries will depend on the ability of U.S. leaders to promote open and fair trade practices in an effort to stimulate sustained economic growth in developing and transition economics.

Administration officials and Congressional members can take a number of steps to open energy markets. For example, they can:

- Include energy when negotiating Western Hemisphere free trade agreements.
- Work with the new government in Mexico to allow U.S. companies to participate in the oil, natural gas, coal and electric power sectors.
- Work with Canada as well as Mexico to develop a North American energy trade strategy.
- Incorporate as broad a definition of energy services as possible in the World Trade Organization's upcoming round of negotiations on "services."
- Drop unilateral trade and economic sanctions.
- Support the opening of markets currently closed to U.S. companies as a cornerstone of U.S. foreign policy.
- Utilize U.S. influence and credibility to discourage actions that damage the U.S. economy by the Organization of Petroleum Exporting Countries.

The new Administration should refocus development priorities, giving top priority to programs that encourage domestic resource development and utilization. For example, policymakers could establish a more direct link between trade promotion and international development. After all, emerging democracies cannot develop into modern, civil, stable societies unless those nations provide their citizens affordable and reliable energy supplies. Additional U.S. assistance would help develop these much-needed energy supplies.

For example, hospitals cannot refrigerate vaccines, schools cannot provide adequate lighting and clean water systems cannot function without energy. Poverty stricken families in Africa may spend eight hours a day gathering fuel wood and animal waste to burn for light and heat. Providing basic supplies of energy can allow a mother these eight hours to teach children to read or to raise a crop for income. The cycle of poverty will never be broken without access to energy.

The World Energy Council indicates that as many as two billion people lack access to energy. The potential for social instability from poverty is a clear threat to U.S. security and our national interests. Increasing the supply of reliable and affordable supplies of energy to stimulate economic growth in developing and reforming nations must be a cornerstone of U.S. foreign policy.A new model of foreign assistance launched in 1990, energy partnerships, has proven to be more effective than traditional models in this area. The U.S. private sector, by donating their expertise, have fostered the development of economic climates conducive to trade and direct investment by U.S. corporations. These efforts have led to one dollar of matching expenditures by U.S. private sector organizations for every dollar of U.S. government assistance.

Another priority should be fostering international trade and investment, which is best done by creating appropriate legal, regulatory, tax, trade and financial frameworks that open markets and facilitate foreign investment. Energy related economic development assistance has created investment and trade opportunities in South America and Eastern Europe and are on the verge of paying off in Asia and Africa. These programs administered by the U.S. Agency for International Development (USAID) should be expanded.

Funding of programs to support international development, export and investment also should be strengthened in the U.S. Department of Energy, Trade & Development Agency, Export-Import Bank; Overseas Private Investment Corporation and the U.S. Department of

Commerce. Jobs for Americans and employment opportunities for citizens of client countries are enhanced when energy driven economic growth becomes possible in developing and transitional economies. Global trade and investment in creating the energy infrastructure critical for a modern, civil, democratic society pays dividends in terms of U.S. energy, economic and national security.

The need for global attention to developing countries energy requirements rivals the need after World War II for a Marshall Plan to rebuild Europe. In fact, an energy Marshall Plan for developing countries and transitional economies can re-establish U.S. global leadership in this area and mitigate our domestic energy problems and improve our economic and national security.

Energy Research, Development, and Deployment

Technological advances have allowed us to find, produce, transport and utilize energy in ways unimaginable only a few decades ago. Technology has contributed dramatically to an energy supply system that is efficient, safe, and environmentally secure. Future technological advances are expected to stimulate continued improvement in all of these areas as well as contribute to a diverse, robust, and economical energy future.

However, investments to maintain and improve the existing energy system have declined over the past few years, thus jeopardizing system reliability. The downward trend in investment is in part responsible for a rash of power system interruptions in the eastern and midwestern regions of the country in the summer of 1999, and the rolling blackouts in California in 2001.

Paralleling the reductions in investment in capital improvements is a sharp decline in both public sector and private sector energy R&D expenditures during the 1990s. Analysis currently underway within the World Energy Council indicates that this phenomenon is not limited to the United States, but is true of all OECD countries. Total research appears to be less than half of 1990 levels. Increases in research and development budgets are needed to create a new technology base on which to build modern infrastructures for the production and delivery of oil, natural gas, coal and electricity.

A key element of technology advance is the achievement of consensus on the issue of the role of the federal government in research, development, and deployment. Particularly in the case of technologies for critical energy infrastructures, where system failures can have consequences that reach far beyond state boundaries, a role for the federal government should be defined. In addition, where technical and business risks of new technologies are high, risk sharing through collaborative leadership initiatives involving the public and private sectors seems appropriate.

Priority should be given to research efforts that can contribute to production and utilization of domestic energy resources. The federal government should focus on basic and applied research that can increase energy supply while improving both energy efficiency and environmental protection. Research and development priorities should be reviewed to insure that those energy sources most likely to contribute to a diverse and robust fuel supply system over the next twenty years are adequately funded. Increased federal funding for research and development in all arenas—oil, gas, coal, nuclear, and renewable energy—should be considered.

Initiatives to improve energy delivery—including natural gas pipelines, electricity transmission systems, and energy storage facilities—also require increased funding. Near-term programs are needed to ensure reliability of supply while system upgrades are needed to handle the new patterns of traffic on electricity transmission systems and pipelines caused by wholesale and retail competition. Finally, new technologies must be developed to begin the process of transforming the entire electricity power system—from generation to end use – into the equivalent of continental-scale integrated circuit, able to respond rapidly to changes in system loading while retaining power stability. The result will be a digital infrastructure that links an upgraded transmission system to a new distribution system, capable of supplying all customers with affordable, abundant energy, and differentiated energy products and services.

U. S. public spending for R&D should be better coordinated with other OECD countries. Doing so will improve the efficiency of research efforts and minimize duplication of efforts. U.S. research programs should reflect the potential for applications outside the U.S., particularly in developing economies. As energy issues increasingly become global concerns, federal government investments in R&D will have higher paybacks if the new technologies are deployed globally as well as domestically.

Education and Public Awareness

Well-educated energy consumers enhance market efficiency, especially in an era of deregulation. Accordingly, policies that promote consumer awareness and education about key energy issues need to be an integral part of the proposed National Energy Strategy.

Workers in the energy sector can also benefit from education and training. This is particularly true at a time when labor markets are tight and enrollments in energy related disciplines are declining at most colleges and universities. The explosive growth during the 1990s of information technology companies—which compete directly with potential energy workers, especially for technically-trained people—has reduced the workforce pool for energy companies. Unless action is taken soon, the U.S. education system may be unable to produce a sufficient number of well-trained graduates to meet demand in the coming decades.

Balancing Energy Demand and Environmental Concerns

Energy and environmental issues have become inextricably linked to one another, and to national policy decisions. This linkage is both broad and deep, and involves concerns about air quality, toxic wastes and global climate change, to name a few policy issues. Balancing the economic efficiency and reliability of a competitive energy market with appropriate environmental policies is key to developing an effective National Energy Strategy. When balancing America's energy needs and our nation's broad economic and social goals, policymakers should be guided by sound scientific and economic analysis. They should also apply cost-benefit and risk analyses when reviewing environmental laws and regulations.

In short, environmental regulation should be formulated in a way that achieves reasonable environmental objectives while recognizing the on-going need to provide companies and consumers a reliable and affordable supply of energy so U.S. economic growth remains robust.

Global Climate Change – a Way Forward

Climate change is a long-term global issue that, in the last decade, moved from a scientific question into the international political arena. As recently as 1990 the United Nations-sponsored Intergovernmental Panel on Climate Change (IPCC) reported that a global warming trend may be underway, and that greenhouse gases emissions from human sources may increase the potential impact of global warming. The IPCC recommended that an international agreement be negotiated setting forth a pathway to limit man-made greenhouse gas emissions, especially energy-related carbon dioxide emissions. In 1992, 160 nations heeded this advise and signed the Rio Agreement on Climate Change, formerly known as the "United Nations Framework Convention on Climate Change" (FCCC).

The United States was among the nations to ratify this agreement, which has as its objective stabilizing the atmospheric concentration of greenhouse gases at a level that prevents dangerous anthropogenic interference with the climate system. In ratifying the FCCC, the United States, Europe, Japan and other industrialized countries agreed to take the lead in modifying longer-term trends in anthropogenic emissions, to make best efforts to reduce emissions to 1990 levels by 2000 and to provide technology and funds to developing countries to ensure that emission levels would remain as low as possible—without jeopardizing economic development.

In the months that followed, many U.S. companies, and even entire industry sectors, began to develop programs to increase operating efficiencies, put new technologies in place, and implement business practices aimed at lowering greenhouse gas emissions—while, at the same time, maintaining a growing U.S. economy. These voluntary programs, often in conjunction with government partners, have paid off. Recently, the Department of Energy released a report showing that U.S. greenhouse gas emissions are more than two hundred million tons per year lower than they would be had industry and business not taken these voluntary actions.

A sound long-term climate change policy that complements a sound long-term energy policy must be developed to ensure that the greenhouse gas emissions growth line continues to bend downward while the economic growth curve continues to move upward. Sound climate change policies can make this happen, particularly if these policies:

- Emphasize voluntary action;
- Are cost effective, flexible and focus on long-term solutions that recognize that our economy is built on the availability of reasonably priced energy of all forms;
- Address both cost-effective mitigation actions—such as avoiding emissions through enhanced energy or operating practices—and adaptation to changes that occur for whatever reason;
- Expand research programs that address science, economics and technology development;
- Remove barriers to the deployment of new technologies and encourage rapid deployment through incentives;
- Address the needs of developing nations, including their desire to build their domestic capabilities and grow their economies; and,
- Encourage local action and actions by governments as well as by industry.

Unfortunately, as we enter the 21st Century U.S. climate policy is not based on a long-term strategy. Over the last three years, the US Administration's strategy has been short term and directed at ratifying and implementing the 1997 Kyoto Protocol. This agreement, concluded in December 1997, would require the U.S. and other developed countries to meet mandatory emission reduction targets by 2008-2012. For the United States, the Kyoto Protocol would mean a reduction of greenhouse gas emissions to a level that is seven percent below 1990 levels with additional, but as yet unidentified reductions, after 2012. To meet the initial target the U.S. would have to cut its emissions by 30-35 percent below projected levels. Doing so would be very costly. Most analyses show that reaching this target in such a short time period would reduce the U.S. GDP by several percentage points.

To date, the Kyoto Protocol has not been submitted to the U.S. Senate. If it were, it likely would not be ratified, which is a requirement for the United States to be bound by that agreement. The United States in not alone in its concerns about the impact of the Kyoto Protocol. As of January 2001, no developed country has ratified the agreement. Most nations realize that the Protocol would require significant changes in energy, economic and trade policies and would seriously affect the lives of every citizen. Moreover, the European Union has strenuously resisted elements in the Protocol that theoretically could reduce the cost of compliance. These elements include a proposed emissions trading program, the Clean Development Mechanism (directed toward emissions abatement in developing countries) and land use and forestry programs. Such elements are key to offsetting costly short-term mandatory emission reduction targets. To date, nations are looking for reasonable and cost effective approaches to deal with the climate issue. Increasingly, it is appears likely that most nations will concentrate on new technology development, deployment and transfer to limit greenhouse gas emissions.

In the decade ahead, the federal government should seek to meet the commitment expressed in the FCCC by devoting sufficient scientific resources to determine the maximum atmospheric concentration of greenhouse gases that would "prevent dangerous anthropogenic interference with the climate system" (From Article 2 of the FCCC). Additionally, the U.S. should work with other nations, including developing countries, to establish an equitable long-range plan to prevent the exceeding of this unacceptable concentration. This plan should include all market-based measures that contribute to the ultimate goal, including making maximum use of cost-reducing implementation measures. Moreover, governments should work with industry to develop a broad suite of technology options from which energy users could select in order to meet climate change policy goals in 2050, 2075 and 2100.

POLICY RECOMMENDATIONS

Competitive markets, investment tax credits, deregulation, environmental impact statements and licensing permits are among the tools available to National Energy Strategy policymakers. The following are the policy recommendations and tools that members of the United States Energy Association believe would most effectively help a wide array of U.S. energy producers and energy-related service companies meet America's growing demand for ready, reliable, secure and affordable energy resources:

Enhancing Energy Supplies

- **The nation should encourage power supply expansion with policies that fully recognize that no single energy source can meet our growing energy needs.** This means that any federal incentive that encourages energy production should promote maintenance of a diverse energy portfolio made up of fossil fuels, nuclear and renewable energy sources. Sufficient availability of basic energy fuels as feedstock for non-energy applications should also be considered in the development of a diverse energy portfolio.

- **Policies that restrict access to energy sources should be modified to provide environmentally sound access to domestic resources in a way that supports the continuance of a diversified energy portfolio and reduces foreign dependence.** Such policies should not merely focus on one aspect of the energy supply system, but rather support and encourage all components of a sector's production and delivery of its energy supply (e.g., from oil exploration and production through the building of refining capacity). Congressional mandates under the Federal Land Policy Management Act and related acts should be adhered to. These acts require agencies to give balanced consideration to multiple competing uses of federal lands. Experience has shown that federal lands do not have to be restricted solely to environmental or aesthetic uses.

- **National policy should specifically focus on diversifying energy resources in the national portfolio.** The U.S. Strategic Petroleum Reserve should be maintained and utilized only for severe supply disruptions.

- **Investment tax credit mechanisms and accelerated depreciation (or equivalent mechanisms) should be primary government tools to encourage reliable, affordable and environmentally effective energy supplies, end-use technologies and a sound energy infrastructure.** Private investment should be encouraged through flexible tax mechanisms that insure equitable opportunities for all energy sectors. In the interest of stimulating the use of the most market efficient technologies, tax incentives should encourage facility construction but not subsidize the delivery of products to consumers.

- **Tax incentives should be enacted to spur capital investment in the energy sector.** These tax incentives will help the U.S. energy industry ensure adequate and uninterrupted energy supplies and services to U.S. consumers and enhance U.S. national security through the preservation of a viable domestic energy industry. For example, expensing of geological and geophysical (G&C) expenditures for oil and gas wells should be enacted. Tax incentives should also be utilized to encourage energy efficient capital stock.

Encouraging Energy Efficiency and Affordable Prices

- **Energy efficiency should be promoted through governmental policies that focus both on production and demand.** For example, the convergence of retail competition, wholesale competition, and improved technologies should greatly expand the type and magnitude of price-responsive demand in electricity markets. Efficiency products should be promoted through directed research and subsequent market availability. Artificial efforts to mandate market penetration of efficiency schemes should be avoided. Regulatory polices that allow and encourage retail customers to respond to market prices will improve economic efficiency, discipline market power, improve reliability, and reduce the need to build new generation and transmission facilities.

- **Policymakers should rely on a properly structured marketplace for energy decisions regarding pricing, technology deployment, energy efficiency, and selection of fuels and energy suppliers.** Market competition is a dynamic process that produces long-term benefits for the public. Governmental policies should seek to establish and preserve the conditions necessary for efficient competition to work. Government officials at all levels should only cautiously impose new regulations on the energy chain. Moreover, efforts to address health, safety, and environmental concerns should be based on sound science and cost-effective options. Specifically, regulations should not be imposed in the hope of reaching a goal that researchers cannot demonstrate as achievable at a reasonable cost.

- **Energy markets should be free and competitive, and utilities should be allowed to compete fairly in these markets.** Energy markets have been opened to competition, and increasingly consumers need to be free to buy their energy and energy-related services from whichever supplier they choose, including natural gas and electric utilities that wish to offer these services. Regulatory authorities should reject attempts to impose restrictions or competitive handicaps that limit the ability of distribution utilities to compete in newly emerging energy service markets, while ensuring against cross-subsidization between regulated and unregulated businesses. By doing so, regulators can preserve the social benefits of efficient competition in energy markets.

- **The low-income home energy assistance program (LIHEAP) should be extended and funding increased.** Currently LIHEAP funds are reaching only 15% of the house-holds eligible for assistance. The low-income weatherization program should also be expanded.

Stimulating Global Energy Trade and International Development

- **U.S. leadership in energy services and technology should be promoted on a global basis.** Artificial constraints on exports and global market penetration should be severely limited. For example, unilateral trade sanctions damage U.S. companies, workers and consumers by excluding them from key markets in which foreign-based companies are free to invest.

- **Tax provisions which diminish the international competitiveness of U.S. multinational energy companies by exposing those firms to double taxation (i.e., the payment of tax on foreign source income to both the host country and the United States), and to restrictive anti-deferral rules, should be eliminated.** The complexity of the U.S. international tax rules obfuscates tax planning and often introduces substantial risks, hindering effective capital investment.

- **A cornerstone of U.S. foreign policy and development assistance should be to institute a "Marshall Plan" to increase the supply of reliable, affordable and market-based energy for developing countries and countries in economic transition in a manner that opens markets to U.S. goods and services, fosters cooperative partnerships between the U.S. and overseas energy firms, and enhances international economic and political security.** This plan would encourage the export of advanced U.S. technologies, policies and practices appropriate to developing countries for the efficient supply and use of energy.

- **Foster more open political, legal and institutional structures in developing and reforming countries so as to encourage energy trade and investment.** U.S. expertise and technology can be utilized to serve the global market through capacity-building, sectoral reform and financing.

Promoting Energy Technology Development and Long-Range R&D Initiatives

- **Investments in energy technology research and development should focus on energy sources and uses that realistically can be expected to have a significant impact on economic growth and environmental performance over the next 20 - 30 years.** This requirement implies the development of a balanced portfolio of energy sources and fuels (fossil, nuclear, renewables) to promote national security. Structural changes and technologies that increase the flexibility and value to the user of the energy system should also be encouraged. Finally, technologies must be developed to assure that we will be able to handle increased traffic levels and meet the needs of a digital economy.

Balancing Energy Use and Environmental Concerns

- **Government sponsored education programs should recognize the importance of energy infrastructure and energy sources to continued energy security and economic development.** Energy and environment programs should be deployed at all educational levels that recognize energy supply and energy efficiency as critical to the modern economy and national energy security. Maintenance of robust educational programs capable of producing engineers and technicians in sufficient numbers to meet the growing needs of the nation's energy infrastructure should be an important consideration in all government programs affecting educational institutions.

- **The development and deployment of energy infrastructure should favor all technologies that are capable of producing energy at emissions levels below existing national standards.** For example, if investment and production tax credits are used to encourage investment, the credits or other mechanisms should be available to all technologies that produce end-use energy below the emissions standards without the application of administrative credits. Moreover, national policies should promote—at current or better levels—the maintenance of non-emitting energy technologies in the nation's energy portfolio.

- **The safe and efficient movement of energy goods and services requires that increased attention be given to improving the United States transportation infrastructure.** For example, oil products and coal are heavily dependent on safe waterways and harbors and coal relies greatly on adequate railroad capacity. Most movement of energy goods and services require a well maintained road system.

Unifying the Energy Policy Process and Creating Regulatory Predictability

- **The President should establish an interagency task force on energy policy chaired by the Secretary of Energy.** The membership of the task force should include economic policy departments and agencies and the appropriate national security organizations.

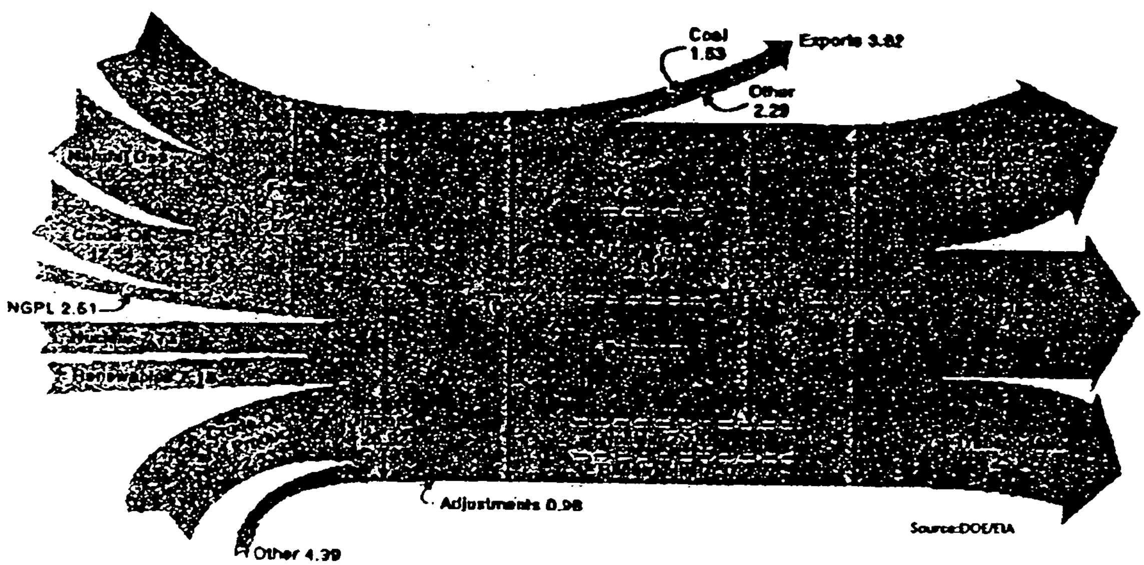
- **Energy Policy must be predictable.** In recognition of the capital-intensive and durable nature of energy infrastructure investments, energy policy requires the adoption of a long-term view. Private investors in energy projects must be able to plan such investment with the reasonable certainty that, once begun, a project can operate in a regulatory climate, which safely can be forecast for the duration of the construction period and operating life of that facility. Revised regulatory standards should not be imposed until acceptable technology to achieve the new standards is demonstrable. This requires the use of fresh approaches to coordination by relevant agencies, such as regulatory bodies and those federal agencies responsible for sponsoring energy R&D. The net effect may extend considerably the time required to alter regulatory standards, but this approach is consistent with practices affecting operating licenses, which, at least nominally, provide for use of a new facility for four or more decades.

- **Comprehensive electric industry restructuring should seek to encourage long-term improvements to the electric system.** Finding the right mix of market solutions and government oversight to ensure an economical and reliable electricity supply will be difficult—but is possible. For example, 17 electricity restructuring bills were introduced in the 106th Congress. While no consensus legislative package has yet developed, significant issues embodied in the proposed legislation include, among others, repealing PURPA and PUHCA, facilitating new state restructuring actions by resolving federal/state jurisdictional issues, resolving market power and transmission access problems, and grandfathering existing state restructuring plans to protect them from federal preemption. Tightly linked with the emergence of efficient competition in the electric industry is the need for comprehensive tax legislation that facilitates the construction of new transmission facilities and provides fair electric competition among publicly owned, cooperatively-owned and shareholder-owned electric companies.

Moreover, Congress and policymakers should develop polices that promote investment in new generation and transmission lines. Policies should also promote voluntary flexible approaches to the creation of regional transmission organizations and electricity markets. Finally, the North American Electric Reliability Council should evolve into a self-regulating organization, with FERC oversight, that enforces reliability rules on all transmission operators and users.

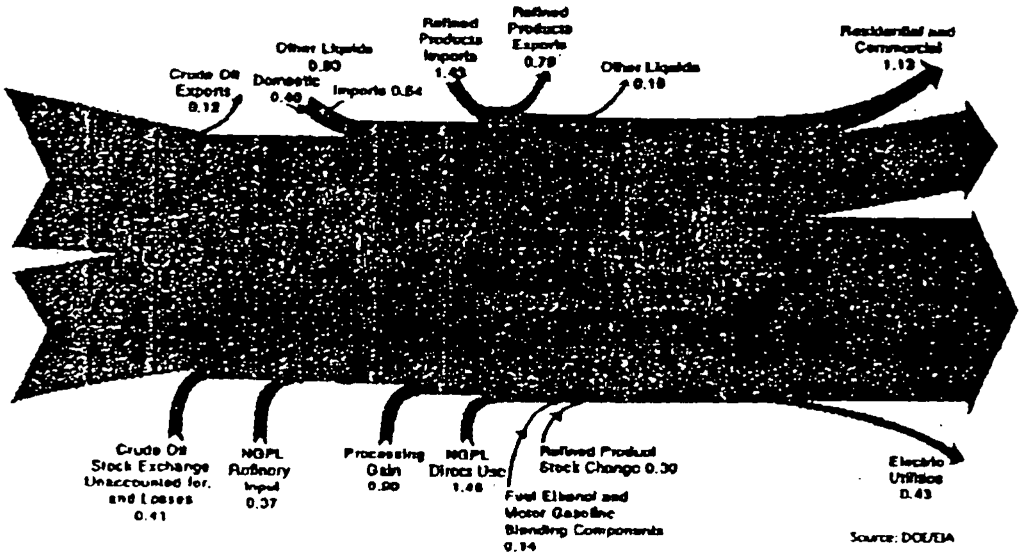
INDUSTRY SECTORS

U.S. Energy Flow Chart 1999
(Quadrillion BTU)



PETROLEUM

Petroleum Flow Chart 1999



OVERVIEW

While petroleum currently supplies 40 percent of America's primary energy needs, reliance on this fuel varies greatly by sector. For example, petroleum supplies 97 percent of transportation needs, 35 percent of industrial needs, 8 percent of commercial needs and 13 percent of residential needs. The most common—and important—petroleum products are gasoline, diesel fuel, kerosene, heating oil, residual fuel oil, liquefied petroleum gases, asphalt and petrochemical feedstocks.

Since 1970, production of crude oil has declined from 9.6 million barrels per day to 5.8 million barrels per day. At the same time, consumption has increased from 14.7 million barrels per day to about 20 million barrels per day, or some 300 billion gallons per year. During these same 30 years, oil imports have increased from 23 percent of U.S. petroleum demand to the current level of about 55 percent. The U.S. Department of Energy's Energy Information Administration forecasts that petroleum demand will continue to grow during the next two decades.

The Energy Information Administration's (EIA) Annual Energy Outlook 2001 highlights several other important facts about the role of petroleum in our nation's future:

- Net petroleum imports are projected to increase to 64 percent of U.S. demand in 2020.
- The greatest growth in petroleum demand will occur in the transportation sector, where increased travel more than offsets fuel efficiency gains.

Clearly, petroleum will provide a major source of energy for years to come.

EMERGING CONSUMPTION PATTERNS

The Energy Information Administration projects an increase in demand for all petroleum products of 1.4 percent per year for the next twenty years, or slightly higher than the 1.3 percent per year that EIA projects for all energy sources during this same period. This projection for higher petroleum demand comes at a time when consumers have endured a heating oil price spike and a gasoline price spike, and at a time when petroleum refiners have faced significantly higher crude oil prices.

As demand has increased and supplies tightened, the Organization of Petroleum Exporting Countries (OPEC) has reasserted its grip on world oil supplies, keeping crude oil prices above $30 per barrel for almost one year. U.S. imports of crude oil and products have grown during this same period, as has utilization of refinery capacity. Indeed, the petroleum industry continues to strain as it seeks to meet the growing demand for home heating oil, gasoline, diesel fuel and petrochemicals. In recent months the U.S. economy has slowed somewhat, but overall economic growth remains a healthy 2.4 percent and demand for petroleum continues to grow despite higher product prices.

EIA's Supply-Demand Scenario

In Annual Energy Outlook 2001, EIA analysts set forth a scenario that they believe will close the gap between rising petroleum imports and product prices and America's need for affordable, reliable energy supplies. Here are the outlines of that scenario, which looks out to the year 2020:

- Crude oil production declines by 0.7 percent per year.
- Crude oil imports increase by 1.6 percent per year.
- Petroleum product imports increase by 4.6 percent per year.
- New light duty vehicle efficiency increases from 24.2 to 28.0 miles per gallon.
- Freight truck and aircraft efficiency increase by about 0.7 percent per year.
- Refinery capacity expands from 16.5 to 18.2 million barrels per day.
- Refinery utilization increases from 93 to 95 percent.

Policymakers concerned about our nation's economic and energy future must decide whether this scenario is realistic. While it is impossible to assess precisely the likelihood of any forecast, or even the many elements of the EIA forecast, it is possible to compare EIA's projections to historical experience. It is also possible to identify the policy assumptions used to create this forecast and, of equal importance, to present a series of ideas to help policymakers forge an effective National Energy Strategy for the decades ahead.

History vs. Projections

EIA analysts argue that domestic crude oil production will slow significantly during the next 20 years. However, when they quantify that argument, they propose a modest decline in petroleum production of a mere 0.7 percent per year. This figure does not represent historical trends, which show a decline in U.S. crude oil production during the 1990s of some 2.5 percent per year. This slower rate of decline in petroleum production translates into a lower than expected rate of growth in crude imports, at least in EIA's scenario.

More specifically, EIA forecasts that during the next two decades the United States will increase its crude oil imports at the modest rate of 1.6 percent annually. However, during the past decade, U.S. crude oil imports actually increased a substantial 3.9 percent per year. The EIA scenario for petroleum products also is at variance with the historical record. EIA projects that petroleum product imports will increase at the rate of 4.6 percent per year. During the past decade, petroleum product imports actually declined by 1.2 percent per year.

History is no guide, either, to EIA projections about increases in vehicle efficiency. The EIA scenario foresees a faster rate of vehicle efficiency in the next two decades than occurred during the past decade, but the projected rate is slower than the actual rate of improvement during the mid-1980s.

On the other hand, EIA projections hew fairly close to historical fact in the area of petroleum refinery capacity and utilization. During the past decade, U.S. refinery capacity has increased a total of approximately 850,000 barrels per day. This figure is comparable to EIA's forecast that within two decades, U.S. refinery capacity will have increased 1,700,000 barrels per day. The projected increase in refinery capacity utilization also appears to be close to the likely mark. While capacity utilization has increased from 86.6 percent to 93 percent during the past decade, EIA analysts forecast an increase of 2 percentage points by 2020.

POLICIES TO MEET AMERICA'S GROWING PETROLEUM DEMAND

While EIA's forecast is often at variance with the historical record, both history and EIA's most recent forecast indicate that petroleum demand will grow significantly in the decades ahead, even if all projected energy efficiency gains are realized. The only way to meet this increased demand for petroleum is to adopt national policies that support growth in petroleum supplies. The alternative is to limit demand by imposing sharply higher petroleum prices on U.S. homeowners, commuters, transportation companies and factories. However, these higher prices would slow U.S. economic growth.

Ensuring Adequate Supply

A National Energy Strategy can be developed that meets America's growing demand for petroleum without substantially raising prices. Studies have shown that vast amounts of proven crude oil reserves and undiscovered crude oil resources exist, both domestically and abroad. However, polices that support continued investments in finding and producing these resources are needed to bring these crude oil supplies to market.

Companies will make the decisions to invest in finding and producing the needed petroleum once policies are in place to support such long-term capital commitments. Unfortunately, the recent EIA forecast simply implies that significant investments will be made, domestically and abroad, without addressing the need to develop policies favorable to increased crude oil production.

The same is true of petroleum products. Stakeholders must come together to adopt policies that insure an adequate supply of gasoline, diesel fuel, home heating oil and petrochemicals. Concerns about environmental impact should take into consideration the unparalleled improvement in exploration and production technology. For example, the exploration footprint has been improved by 90 percent during the past decade, and similar, if less dramatic examples, exist in other areas of petroleum production.

Ensuring the Security of Petroleum Supplies

As noted, EIA analysts forecast a sharp increase in petroleum imports—the current rate of 55 percent to a rate of 64 percent in 2020. This increase in imports raises legitimate questions about security of America's petroleum supplies. What countries can supply this growing volume of crude oil and petroleum products to U.S. consumers? Are these countries reliable suppliers? Do new and more diverse sources of petroleum exist that are not included in the EIA forecast? What role will OPEC play with respect to future oil supplies and prices?

Clearly, OPEC members have constrained supply during 1999 and 2000 and maintained relatively high prices. Will this pattern continue? If new petroleum producing countries join the world energy markets, will these countries become members of OPEC or another cartel?

As these questions suggest, the United States has less control over the security of its petroleum supply as long as we are heavily dependent on petroleum imports. Policies that promote diversification of supply would reduce this uncertainty. So would policies that enhance domestic petroleum production.

Stimulating Needed Investments

Policies that encourage investments in crude oil exploration and production need to be included in the National Energy Strategy. So too, should polices that encourage major investment in petroleum refining, distribution and marketing. For example, the EIA forecasts that an additional 1.7 million barrels of capacity will be needed to meet demand in 2020. Who will finance this increased capacity, and who will build it? Will companies expand existing refineries, or will they need to build new ones—as many as eight to 10 major refineries to meet EIA's petroleum demand projections?

And if refinery capacity utilization cannot increase to the 95 percent level that EIA forecasts, two additional new refineries will need to be constructed. However, no major refinery has been built in the United States during the past 25 years. What policies will Congress enact to support the construction of eight or more new refineries during the next 20 years? What policies will encourage major investment in the pipelines and terminals that will be needed to transport an additional 5 million barrels of oil per day to consumers?

The National Petroleum Council (NPC) published a study in June 2000 entitled "U.S. Petroleum Refining—Assuring the Adequacy and Affordability of Cleaner Fuels." The study assessed government policies and actions that would affect product supply and refinery viability. The study concludes that the refining and distribution industry will be significantly challenged to meet the increasing domestic light petroleum product demand with the substantial changes in fuel quality specifications recently promulgated and currently being considered. The NPC study contains specific recommendations and findings related to petroleum product supply and future refinery viability. The Secretary of Energy, in consultation with the governmental departments and federal agencies, shall report to the applicable committees in the houses of Congress on the findings and conclusions of the NPC study and on the adjustments to federal policy required to implement those findings and conclusions.

Encouraging International Energy Trade and Development

Because the United States faces increased dependence on petroleum imports during the coming decades, U.S. energy companies will need to be able to find and produce oil internationally. American companies are well positioned to do this. Most have gained a technological advantage that ensures a fairly high rate of discovery and production. However, policies to support these international initiatives, which often involve considerable financial risk, need to be place. Some existing tax laws and other public policies hamper international efforts to find and produce oil in promising areas. Such policies should be reviewed and, if needed, revised to strengthen U.S. leadership in new petroleum exploration and production.

Energy Technology R & D

The U.S. petroleum industry is one of the most technologically advanced in the world. In recent decades, American petroleum companies have dramatically reduced exploration and production costs while sharply reducing as well the footprint required for new oil exploration. Policies should be put in place that assign a value to these technological advancements that is equal to the value assigned to technological advances in other energy areas. Certainly, government officials should not select winners and losers. Rather, a range of energy technologies should be encouraged, and the market should be allowed to adopt the most successful technologies as each new technology proves its worth to consumers.

Environment

The U.S. petroleum industry has dramatically improved its environmental performance by investing more than $8 billion per year in environmental initiatives, or a total of more than $90 billion during the 1990s. The industry remains committed to ongoing environmental improvements, but any additional environmental rules or regulations need to reflect sound science and the likely impact of such policies on U.S. petroleum supplies and the U.S. economy.

Indeed, some existing regulatory polices require close scrutiny. Over the years, a patchwork quilt of conflicting and overlapping regulations has made expansion of the petroleum supply structure nearly impossible. Policies should be put in place that reflect growing demands on the U.S. petroleum supply infrastructure as well as the need to maintain environmental quality.

Transportation

The internal combustion engine—running on petroleum—will remain the dominant powertrain for personal vehicles for the foreseeable future. Even if promising advances in fuel cell and hybrid technologies produce a new breed of vehicle, years will pass before these new technologies significantly replace the current U.S. fleet of more than 200 million gasoline and diesel powered cars, buses and trucks.

For example, a recent study by the WEFA Group found that over 80 percent of the vehicles purchased today would still be on the road in 2008. In short, several decades are likely to pass before the current fleet is replaced by a new powertrain technology, or by significantly more efficient vehicles. Policymakers need to bear this hard fact in mind when developing transportation and environmental policies.

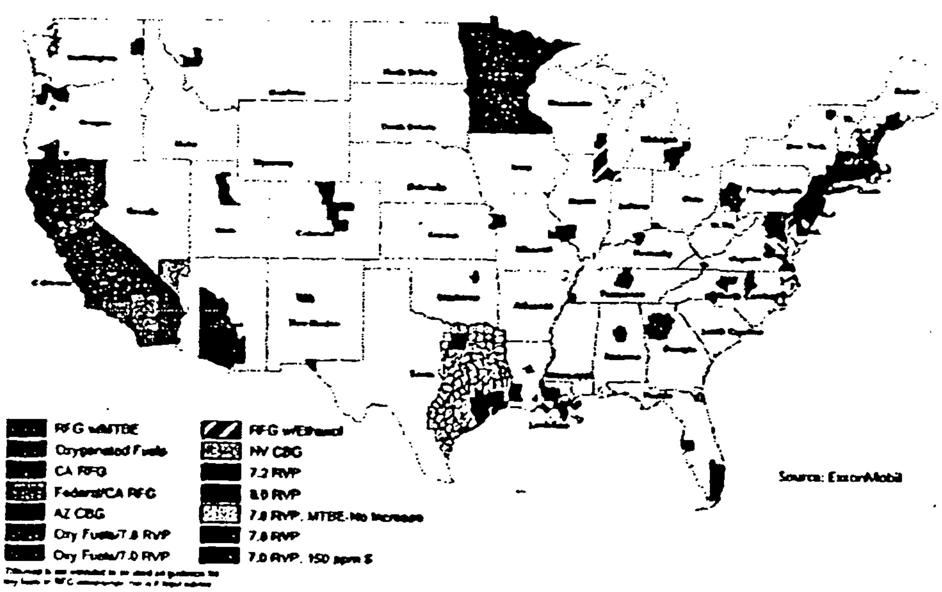
Moreover, most policymakers focus, understandably, on polices that affect cars, pickups and sport utility vehicles. However, other forms of transportation also merit consideration when formulating an effective National Energy Strategy. For example, trucks deliver over 70 percent of America's goods, measured by value. Rails, ships, pipelines and aircraft deliver the rest. All of these transportation modes rely on petroleum as their major source of fuel, not only to move freight but also to move passengers.

To be effective, future transportation policies must reflect the complex interrelationship between petroleum, people, the delivery of goods and services, the environment and economic vigor—and the inestimable capital investment Americans have made in the current transportation infrastructure.

The safe and efficient movement of goods through the United States' port system, including a significant share of energy products, requires that channels be dredged and maintained at safe depths on a consistent basis. Safe navigation also requires accurate and current navigational charts for U.S. waterways. To date, however, these programs have been and continue to be so severely underfunded that it will take the National Oceanic and Atmospheric Administration (NOAA) 20 years to eliminate the survey backlog. Hydrographic survey data, which is the basis for nautical charts, should be collected using the latest hydrographic survey equipment. Some hydrographic data still being used is over 40 years old. All available resources, both public and private, should be fully utilized, without limits placed on the sources of certifiable survey data. The Harbor Maintenance Trust Fund should be taken off budget and used exclusively for harbor services. This would guarantee that resources are available to meet the growing needs of maritime commerce.

Finally, a national energy policy needs to recognize the international nature of oil transportation. Accordingly, the U.S. government should look to and support broad-based international solutions to marine regulatory issues. The International Maritime Organization (IMO) is the appropriate forum for discussions of such issues as vessel operations, ballast water management, marine air emissions, and vessel scrapping. The U.S. needs to remove barriers to the timely replacement of aging domestic tonnage and stimulate a robust domestic fleet.

U.S. Fuel requirements in 2000



Source: ExxonMobil

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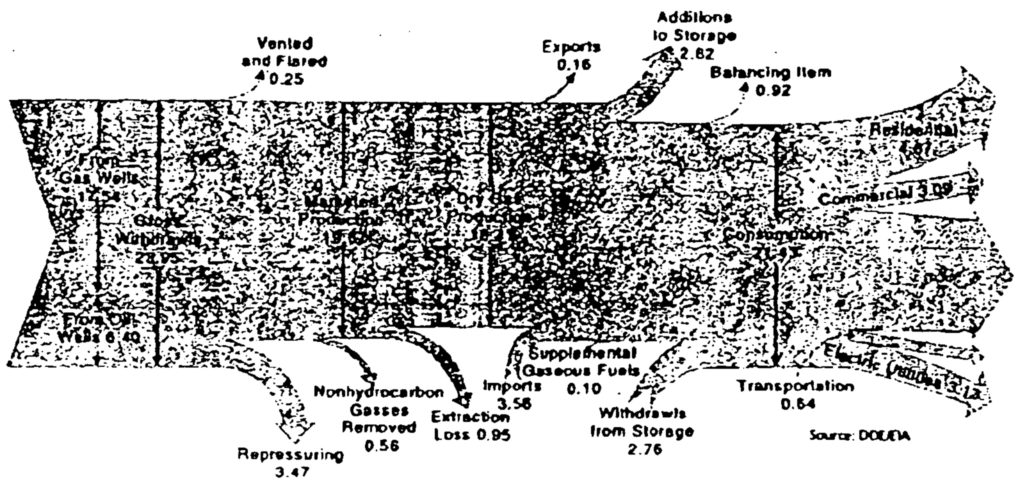
NATURAL GAS

Natural Gas Flow Chart 1999
(Trillion Cubic Feet)



OVERVIEW

Natural gas—a fossil fuel composed almost entirely of methane—accounts for approximately one-quarter of the nation's primary energy consumption. Residential and commercial uses of natural gas include space heating, water heating, cooking, and clothes drying. Natural gas is used by industry both as feedstock in chemicals and in process applications. Moreover, power plants use natural gas to generate electricity, while private citizens use it for space cooling, as a vehicle fuel and in fireplaces.

Three segments of the natural gas industry deliver natural gas from the wellhead to the consumer. Production companies explore, drill and extract natural gas from the ground. Transmission companies operate the pipelines that link gas fields to major consumer areas. And local utilities, acting as distribution companies, deliver natural gas to individual customers.

The number of natural gas consumers has grown through the years, and now totals nearly 175 million Americans. Natural gas from 288,000 producing wells is forwarded by 125 natural gas pipeline companies through a 1.3 million-mile network of underground pipes to more than 1,200 gas distribution companies who provide customer service in all 50 states. Almost all of the gas consumed in the U. S. is produced in North America.

CONSUMPTION PATTERNS

U.S. consumption of natural gas has increased by roughly 13 percent over the last decade, and demand is expected to increase significantly in the future. This growth has occurred in all sectors of the economy. In the residential sector, for example, 70 percent of new single-family homes used natural gas their main source of heating fuel during 1998 and 1999. In the ten years since 1989, U.S. commercial use of natural gas has increased nearly 14 percent, and industrial consumption of natural gas has increased almost two quadrillion BTUs (quads). During this same period, natural gas use to generate electricity has risen approximately 12 percent.

This trend toward greater reliance on natural gas—which is expected to continue—can be attributed to a variety of factors, including favorable economic conditions, superior environmental qualities, and the high efficiency of gas systems. In addition, the natural gas resource base is far stronger than many people realized a decade ago. Moreover, opening natural gas markets to competition in recent years has contributed to efficiency improvements within the industry. The National Energy Strategy should encourage the continuation of these trends.

ENVIRONMENTAL BENEFITS

Natural gas offers numerous environmental advantages relative to many other energy sources. For example, natural gas emits negligible amounts of sulfur dioxide, particulate matter, ash, and sludge. Also, because it emits low levels of nitrous oxide and carbon dioxide, natural gas can help reduce acid rain, ozone, visibility problems, solid wastes and greenhouse gases. Of course no energy source is completely benign with respect to its environmental impacts, but natural gas is an extremely attractive option that can contribute significantly to a number of environmental objectives.

ENERGY EFFICIENCY BENEFITS

Only about ten percent of the natural gas produced is used or lost during production, processing, transmission, and distribution to the consumer. This gives natural gas a competitive advantage over many other energy sources. Equipment that utilizes gas is also far more efficient today than in the past. For example, gas-fired direct contact water heaters used in the textile industry achieve efficiency levels in excess of 99 percent, compared to a 33 percent efficiency level achieved using a prior technology. Similarly, new processes have enabled gas-fired infrared burners to triple their efficiency as well.

RESOURCE BASE

In the decades ahead, natural gas supplies likely will remain strong. Indeed, the North American resource base for this fuel should prove capable of sustaining current consumption levels well into the 21st century, and perhaps beyond. The National Energy Strategy should draw on this secure resource, secure because 87 percent of the natural gas consumed in America is produced in the United States, with the balance coming from Canada. Moreover, Mexico has a large natural gas resource base, and its high production capability makes this neighbor to the South a potential major natural gas supplier.

Although some have characterized the world's gas resource base as "finite," estimates of its size continue to grow. Indeed, as the tools and technologies used to estimate this resource base improve, most estimators have increased their numbers over time. For example, at year-end 1998, the Potential Gas Committee (PGC) estimated the United States' future supply of natural gas at 1,241 quads, or more than 60 years of supply at the current rate of domestic production and consumption. For the past 30 years, PGC members have produced their estimates every other year, drawing on the expertise of hundreds of petroleum geologists and engineers. Interestingly, despite the consumption of more than 149 quads since 1990, the Committee's 1998 estimate exceeds its 1990 estimate (1,207 quads) by 34 quads. This is a 15 percent larger estimate than the 1990 figure, even though significant production (and consumption) has occurred. Much of this increase can be attributed to technological advances, which permit producers to harvest portions of the resource base that previously were unattainable.

PRODUCTION CAPABILITY AND TECHNOLOGY

The National Energy Strategy should reflect the fact that the natural gas resource base has become increasingly diversified. For example, coalbed methane—which accounts for six percent of domestic gas production—was not acknowledged as an important source 10 or 15 years ago.

Tremendous technological advances in natural gas exploration and production also have occurred in the past decade, including three-dimensional seismology, horizontal drilling, and innumerable computer-related breakthroughs. Similar advances will be needed to satisfy potential demand levels. With such advances, domestic gas production can increase from today's 19-plus quads to more than 29 quads in 2020.

Canada will contribute a slightly greater share of total supply in the future by increasing its exports to the U. S. from its current three quad level. Abundant gas resources worldwide and in Alaska offer mid-term insurance, while methane hydrates and other more exotic sources of gas provide long-term potential.

POLICIES TO MEET AMERICA'S GROWING NATURAL GAS DEMAND

The Impact of Deregulation

Policymakers devising a National Energy Strategy will need to consider the dramatic impact that deregulation, or "unbundling," has had on the natural gas industry. Deregulation gives customers the opportunity to purchase natural gas from someone other than the local natural gas distribution company. This trend toward greater customer choice at first gathered strength slowly as local gas utilities increased customer service options, then accelerated dramatically following a 1985 Federal Energy Regulatory Commission (FERC) decision to promote open access to transportation on the interstate natural gas pipeline system for all gas buyers.

By 1999, customer choice volumes accounted for 61 percent of end-use natural gas purchases by customers. Under current and proposed tariffs and choice programs, 81 percent of the volumes could be purchased from a source other than the local gas utility. Almost all industrial and electric utility customers have this option, while almost 70 percent of commercial customers and almost half of residential customers have a choice as well.

Demand Forecast

Natural gas deregulation, the environmental benefits that natural gas can provide, improvements in end-use natural gas applications technologies, and the strong and secure resource base that this fossil fuel enjoys places it in a favorable position vis-à-vis policymakers and consumers in the coming decades. Indeed, both the Energy Information Administration's forecast and the American Gas Association's Fueling the Future study's accelerated demand projections estimate that, by 2020, natural gas consumption could reach 35 quads, compared to a demand for approximately 21 quads in 1999.

While the EIA forecast assumes most of the increased demand will be generated from the electric generation sector, Fueling the Future estimates that nearly half of this projected increase could come in the residential and commercial sectors, where more new customers are choosing natural gas and more existing customers are switching from other fuels to natural gas. The study also shows continued expansion in the amount of natural gas sold for relatively new applications, such as residential gas fireplaces and commercial gas cooling systems. In addition, advances in distributed generation (e.g., reciprocating engines, microturbines, and fuel cells) are anticipated, and these advances could account for roughly 20 percent of all new electricity generating capacity in the coming decades.

Moreover, during the next 20 years industrial gas demand could grow approximately 2.5 quads under the accelerated projection, continuing the robust growth of the past 10 to 15 years. Although the cogeneration market shows signs of saturation, other forms of distributed generation are expected to prosper. Highly efficient heating, cooling and process equipment continues to evolve, enabling natural gas to remain the dominant source of energy for the nation's factories.

Natural gas-powered transit buses, trucks, vans and cars currently consume about one quad more natural gas under the accelerated projection. Although these vehicles account for less than one percent of the overall vehicular market in 2020, they can make significant contributions to air quality and operational economics, primarily in fleet applications in congested urban areas.

Although natural gas consumption used by central-station power plants to generate electricity more than doubles by 2020 under the accelerated case, this figure is lower than the EIA forecast. For example, natural gas would remain the dominant fuel for new generating capacity, even if some new coal-based capacity were to be added after 2010.

More significantly, less new generating capacity is expected to be required under the accelerated scenario than under other projections. That's because the accelerated scenario assumes that the lives of some existing nuclear and coal power plants will be extended and that strong growth will occur in the use of distributed generation. In the increasingly deregulated energy marketplace, consumers will determine the pace at which new energy technologies are brought on line. The forces of the deregulated natural gas marketplace need to be incorporated in a National Energy Strategy.

Investment Needs and the Policy Environment

The U.S. natural gas industry is both large and capital intensive. Existing natural gas industry assets total more than $250 billion, including a 1.3 million-mile transmission and distribution system valued at nearly $150 billion. Of the 1.3 million-mile total, nearly 1 million miles is devoted to distribution. The U.S. natural gas industry also counts more than 400 storage facilities among its holdings. These facilities are often located close to end-user markets, where the gas is injected during off-peak periods and withdrawn in periods of peak demand. The natural gas industry employs more than 150,000 people, and this figure does not include exploration and production employees.

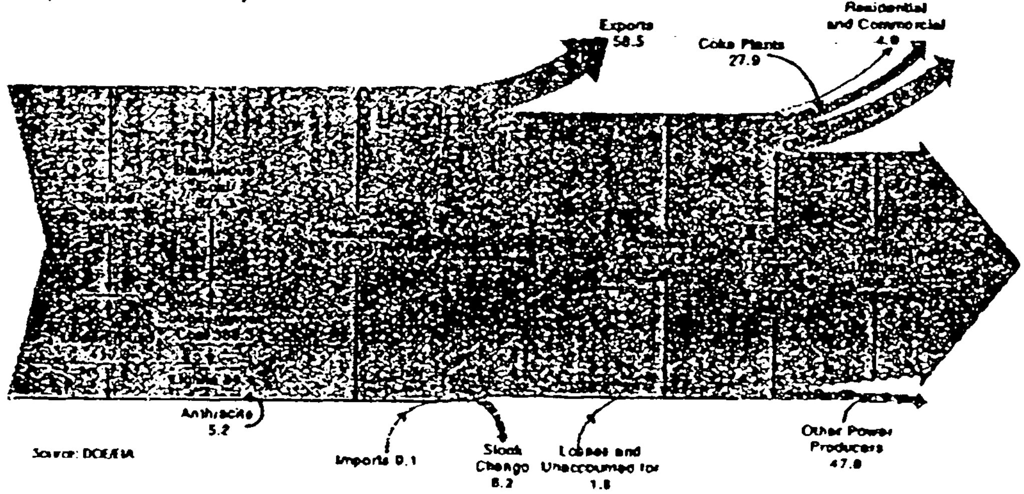
Legislators should develop support ive policies—and remove barriers—so that the natural gas industry can obtain the financing its needs to meet demand forecasts. For example, to meet the 2020 projection, current transmission and distribution line mileage must be increased some 30 percent. Doing so will cost more than $150 billion. Moreover, additions to the distribution system will cost nearly twice as much as additions to the pipeline system. Although these investment levels are certainly significant, they are not dramatically different from the levels experienced in the 1990s — a modest increase for distribution and a modest decrease for transmission.

The investment required for the necessary exploration and production activity assumed in the forecasts will certainly be greater than the requirement for transmission and distribution system expansion. More wells will need to be drilled, and more drilling rigs will be required. Although the number of oil and gas wells drilled per year may have to double—to approximately 50,000 new wells per year—this figure is well below the peak levels of the early 1980s, when from 70,000 to 90,000 new wells were drilled each year.

Finally, formulators of the National Energy Strategy should bear in mind that the natural gas industry's drilling fleet has aged, and that significant investments will be required for upgrades. Capital investments of $40 billion per year ($1998) may be necessary, and acquiring this level of capital may prove difficult in an economy that still places a premium on "high-tech" investment opportunities. However, raising these funds is not an insurmountable task. Compared with the investment levels of the mid-1980s, future investment requirements appear less extreme. Moreover, drilling activity slowed significantly in the 1990s, so the expanded drilling activity needed to meet the accelerated projection demand looks quite dramatic—until one compares it to a longer historical standard.

COAL

Coal Flow Chart 1999
(Million Short Tons)



OVERVIEW

Coal accounts for approximately one-third of the United States' primary energy production, the single largest share of any domestically produced fuel. Estimated recoverable reserves in the United States total 275 billion short tons, or a 250-year supply at today's production rates, according to a 1997 Energy Information Administration update. Reserves are located throughout the nation, and current productive capacity is sufficient to meet the expected continued increase in demand.

Currently, coal accounts for approximately 23 percent of U.S. energy consumption. While coal is primarily used to generate electricity, it is also essential to the production of steel and cement. Other industries, including paper and chemical manufacturers and the food processing industry, use coal to create steam and electricity. Finally, coal is used to generate heat in some small commercial establishments, but this use is diminishing rapidly.

Coal is an affordable and reliable domestic energy source and therefore contributes significantly to the security of the nation's overall energy supply. The coal that is not consumed here is exported to other major industrial or emerging economies, thus contributing positively to the U.S. balance of trade and the global economy.

PRODUCTION AND CONSUMPTION PATTERNS

The U.S. coal industry grew at a slow but steady pace during the 1990s. Production increased an average of 1 percent per year and is expected to reach 1.1 billion short tons when figures for the year 2000 are finalized.

Coal is Produced in 26 States

An effective National Energy Strategy will take into account the fact that coal is produced in 26 states, which the industry typically groups in three geographically distinct regions:

- The Appalachian states, ranging from Pennsylvania to Alabama, which produce approximately 40 percent of the nation's coal, the entire nation's metallurgical coal, and most of our export coal. Underground operations are dominant in this broad region.
- The Interior states, which include Illinois, Indiana and Western. Kentucky. Here, steam coal is produced by medium sized surface mines.
- The Western states, and particularly Wyoming—the largest coal producing state in the country—which use large surface mines to produce steam coal.

During the past decade, coal production has shifted from the eastern to the western United States. For example, in 1999 more than half the 1.1 billion tons of production originated in western states. Moreover, as demand has increased for lower sulfur coal, larger users of coal also have shifted from east to west.

Economic Benefits

The U.S. coal mining industry generates some $160 billion in economic activity, including $19 billion in revenue for federal and state governments and $105 billion in income to coal and its supporting industries. The coal industry directly employs 80,000 workers, and the nearly one million industry-related jobs produce $37 billion in annual wages throughout all 50 states.

Productivity, Reserves and Demand

During the past decade, productivity in the coal industry has nearly doubled. This trend is expected to continue as new technologies and more productive mining methods are brought on line. These same new technologies make mining safer than ever. Moreover, new technologies and advances in mining techniques have increased coal resources and output while protecting the environment. Whether meeting air or water quality standards, protecting wetlands or reclaiming surface mined land to better than original conditions, coal producers meet and exceed all current legal standards. The industry is committed to continuing this high level of performance.

POLICIES THAT THREATEN MINING CAPACITY

Current production capacity and coal reserves are sufficient to meet any increase in domestic demand. However, at least two current policies discourage investment that would expand coal mining capacity in the United States. Indeed, several policies could eliminate some current mining capacity. Such policies should be reviewed during the formation of a National Energy Strategy.

For example, the Environmental Protection Agency (EPA) interprets Clean Water Act regulations regarding valley fills in a way that threatens even near term coal production from several operating mines in some Appalachian states. Eliminating production from these mines would strain productive capacity in other coal producing areas and would significantly disrupt the coal transportation system.

Similarly, land access policies affect both current and future coal production capacities. For example, the decision to use the Antiquities Act to declare certain federal lands "National Monuments" effectively removes a large portion of the western reserve base from production. Actions by the Bureau of Land Management and the U.S. Forest Service, which place reserves on federal lands managed by those agencies off-limits to development, also potentially limit mining capacity. Over time, such actions could deplete the U.S. coal reserve base.

LOOKING TO THE FUTURE

Coal Consumption Data

Almost all the 1.1 billion tons of coal produced in the United State is used domestically. In 2000, utilities and independent power producers will use 973 million tons of coal to generate almost 2 trillion-kilowatt hours of electricity for use in homes and businesses throughout the United States. Coal use for electricity is an even 200 million tons, or 25 percent more than coal used by the utility sector in 1990. Coal is a popular fuel for the utility industry because, on a cents-per-million Btu basis, coal remains the lowest cost fuel available for the generation of electricity. This gives coal-fired utilities an advantage in an increasingly deregulated and competitive, market. Moreover, advances in combustion technology have increased fuel efficiency while lowering the emission of all legally identified pollutants.

Coal use is not exclusive to the electric utility industry, however. Steel mills are expected to consume some 28 million tons of special grade metallurgical coal to make coke in 2000. Major industrial users of energy and retail users, such as homes, hospitals, schools and small commercial establishments, are expected to use approximately 70 million tons of coal this year. Finally, in 2000, U.S. coal producers will export 58 million tons of coal to steel mills and electric utilities in Canada, Europe, South America and, to a lesser extent to the Far East and Japan. Given the domestic abundance of coal, import figures are insignificant and are expected to remain so in the coming decades.

Demand Forecasts

All forecasts of future energy demand show that coal will continue to play a vital role in the United States energy picture. Most forecasts estimate that production will increase from today's level of 1.1 billion tons to from 1.2 to 1.4 billion tons by 2020.

In the future, coal is expected to continue to be used to generate electricity, with as much as 1.1 to 1.25 billion tons consumed annually for this purpose by 2020. The deregulation—and increased competitiveness—of the electricity generating industry places a premium on coal, which is both inexpensive and abundant relative to other domestic fuel sources available to this sector of the economy.

Coal use in other markets is expected to remain at current levels for the foreseeable future. For example, coking coal use by U.S. steel mills is expected to remain in the 25 - 28 million ton range in the years ahead. This is a floor below which steel cannot go in the near term, but, because technological advances will likely continue in the steel making process, coal consumption is not likely to grow soon. Industrial coal use also is expected to remain fairly steady at 70 -75 million tons annually over the next 20 years. Export levels will depend on overseas demand, which in turn depends upon each nation's rate of economic growth and environmental policies, particularly those policies directed toward carbon reduction. The competitiveness of coal relative to other fuels likely will play only a secondary role in these export markets.

U.S. POLICY ENVIRONMENT

Whether the anticipated demand for coal is realized in the United States will largely depend on whether policymakers change existing policies that restrict both coal's availability and its use in the electricity sector.

Electric Utility Policy

As discussed in other sections of this report, demand for electricity is expected to continue to increase at a rapid rate during the next two decades. This increased electricity demand should translate into greater coal demand. However, because the electric utility industry is moving from a regulated to an unregulated market environment, both risk and uncertainty have been introduced vis-à-vis coal demand.

On the one hand, competition should dictate that the lowest cost producer of electricity—companies who use coal—should have an advantage in the open market. However, competition can also move generators of electricity toward the lowest risk option when considering new capacity additions, or even maintenance of, or modifications to, existing capacity. These considerations may dampen demand for coal.

Indeed, signs of this trend already are evident. Even though utility executives are thinking about new generating capacity and modifications of the existing fleet, electricity producers are not making investments to increase the use of coal, even though coal is the lowest cost alternative. One concern is that construction or modifications made to accommodate increased coal use will be rendered obsolete by regulation or litigation. Electric generators are facing an unprecedented wave of new environmental requirements, some of which are being imposed retroactively and thus produce protracted court action. For example, although great strides have been made in reducing emissions of SO2 and NOX, and the requirements laid out in the Clean Air Act Amendments of 1990 are being met, the Environmental Protection Agency has proposed even lower caps on emissions than those legally established by the amended Clean Air Act. The possibility of controls on mercury emissions adds yet another uncertainty.

In short, conflicting forces are at work here. The competitive market trend is toward lower cost generation—which argues for greater use of coal—while recent regulatory decisions are pressuring utilities to rapidly lower certain emissions levels—which increases the cost of using coal.

The Kyoto Protocol

The Kyoto Protocol, or the possibility of some other legally binding international agreement to reduce carbon emissions, adds to the uncertainty of the current U.S. regulatory situation. For example, a recent analysis by the Electric Power Research Institute (EPRI) shows that, if all proposed regulations and the Kyoto Protocol were to take effect, the amount of coal-generate electricity would decline to less than 300 million tons by 2020. Clearly, this is an extreme scenario, but a number of environmental issues now under consideration could sharply limit future U.S. coal use, if these issues are not resolved in a reasonable manner.

OPPORTUNITIES IN TECHNOLOGY

The Role of Technology in Energy Policy

A sound technology policy is key to balancing the growing demand for energy and the trend toward increasingly stringent environmental regulations. Effective technology policies will allow coal to reach its full potential, meet required environmental standards, and ensure that the United States utilizes its most abundant and reliable energy resource.

The nation also needs an energy policy which industry and consumers alike can depend upon for long term consistency—in other words, an energy policy that does not change rules in mid-stream, or retroactively, or based solely on political considerations.

During the past two decades, the use of new technologies and improved operating practices have improved the "environmental efficiency" per ton of coal consumed to increase by almost 70 percent. This trend will continue even as new SO2 and NOx controls come on line because advanced retrofit and repowering technologies enhance environmental performance and efficiency of existing coal-based generation plants.

The use of advanced coal technologies that are now, or will soon be, ready for deployment would effectively eliminate emissions that are considered a health risk, as well as substantially improve efficiency. The nation's energy policy must include a technology strategy that incorporates a comprehensive clean coal technology program to assist new and existing coal-fired units to remain competitive and meet environmental requirements. This technology strategy must encourage on-going research. It also must provide financial incentives sufficient to encourage application of advanced technologies at existing units, as well as encourage a program to demonstrate new technology.

Beyond control of traditional emissions, the coal industry also recognizes that carbon sequestration will be vitally important if it is found that reduction of CO2 emissions is necessary. A National Energy Strategy will not be complete unless it includes policies that stimulate the research, development and deployment of technologies to sequester carbon.

Deploying Technologies Internationally

In many countries throughout the world, energy use during the next two decades is expected to increase even more rapidly than in the United States. For example, the International Energy Outlook 2001, published by the U.S. Energy Information Administration, growth in energy consumption in the developing world, excluding Africa but including China, India and the countries in South America, is projected to exceed 3.5% per year through 2020. Conversely, United States and other industrialized countries will see an increase of approximately 1.0 percent or less per year on average. This rapid ramp up in energy use among developing countries will occur regardless of policies in the United States and other developed nations. That's because additional energy will be needed to support economic growth, and larger populations and a rising standard of living in these nations. The World Energy Council cites that up to 2 billion people lack access to commercial energy supplies in 2001 and that unserved population could reach 3 to 4 billion by 2050.

As in the United States, worldwide energy demands will increasingly be met by a reliance on electricity. Accordingly, technologies developed in the United States will need to be deployed overseas in order to meet the expected demand for twice the current level of energy and three times the current use of electricity. With proper technology policies, it is possible to meet these demands while attending to environmental concerns.

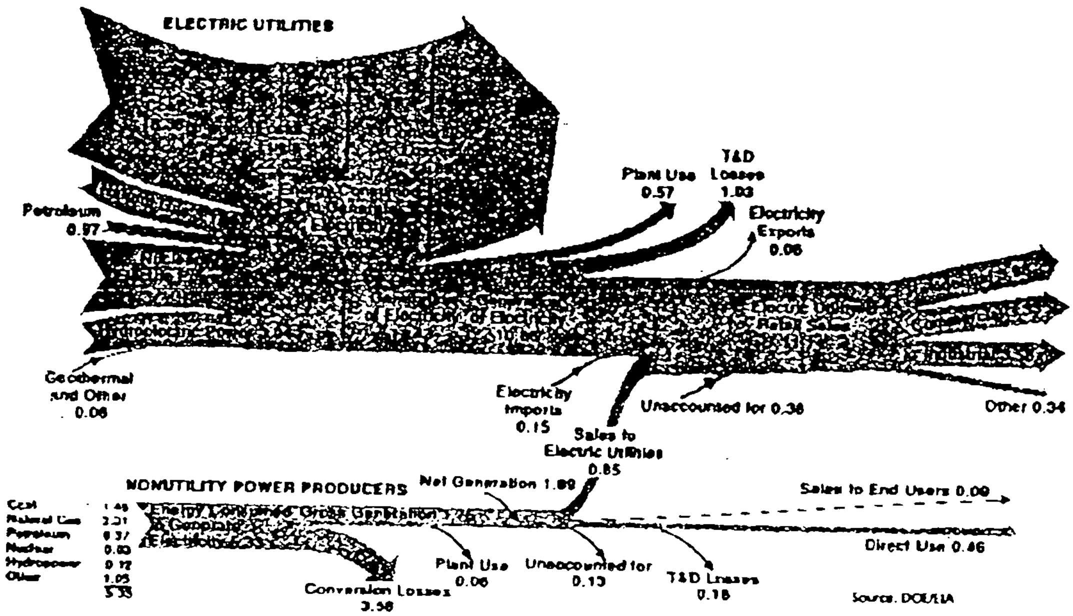
SUMMARY

An effective National Energy Strategy will keep all energy options available in order to meet growing energy demands. Coal can continue to play a vital role in global energy markets. For example, by 2020, some 3.6 billion tons of coal will be consumed in the regions comprising the "developing countries," double current consumption in those countries. Moreover, more than 44 percent of the electricity used in these countries will be generated by coal, both because it is an indigenous resource in many of these countries and because its cost is often low relative to other energy sources.

Clearly, future coal use will not be limited to the developing world. Coal is now, and will continue to be, a major energy resource in all regions of the world. Coal use in the industrialized world will remain at approximately 1.6 billion tons, increasing in the U.S., Canada, Australia and Japan and decreasing only in Western Europe and in the countries of the former Soviet Union. For the foreseeable future, coal will remain an important contributor to the global energy mix.

ELECTRICITY

Electricity Flow Chart 1999
(Quadrillion BTU)



OVERVIEW

Until quite recently, the electric industry has been characterized as a natural monopoly, subject to extensive rate regulation of its generation capacity, transmission lines and local distribution systems. Today, a dramatic restructuring of this industry has forced sweeping changes on the institutions, institutional relationships, and the role of regulators. Some vertically integrated utilities have unbundled their generation, transmission, and distribution functions, and in many cases, sold their generation resources. Increasingly, generation is owned and managed by independent companies or unregulated utility affiliates, not by regulated companies, and output is sold at market-based rates. Moreover, the Federal Energy Regulatory Commission (FERC) and some industry participants now seek to establish new regional transmission organizations (RTOs). Policymakers may also remove federal barriers in order to promote effective wholesale competition and facilitate state restructuring activities and retail competition.

Retail markets were most immediately affected by the Congressional passage of the Energy Policy Act of 1992 (EPAct). This bill modified federal laws in such a way as to facilitate wholesale electricity competition. Today, all fifty states and the District of Columbia have considered some reform of their retail electric service system. Moreover, almost all of the so-called "high-cost" states (i.e., where average rates are above the national average) have adopted retail competition systems that involve non-discriminatory access to the local distribution system and customer choice of energy supplier. Currently, more than 60 percent of the U.S. population lives in the 24 states and the District of Columbia that have decided to transition to open access for retail energy suppliers and customers. State officials continue to address difficult transition questions, including how to handle stranded costs, consumer education and protection, public benefits programs, and residual obligations of incumbent utilities following liberalization.

The recent problems in California's electricity markets, however, are having national implications that impact all stakeholders in the electric industry. Extreme price volatility and shortages in the California market have been brought about, in part, by inadequate market design and public policies that are incompatible with an efficient market environment. As a result, the pace of deregulation and the transition to retail competition in the other states may be affected. In the emerging market environment, it is important that public policies facilitate new investments in generation and transmission.

PATTERNS OF CONSUMPTION

Although many consumers can now choose their retail electricity supplier, most have chosen to remain with their incumbent supplier, the utility distribution company. One reason they have chosen not to switch is that state-mandated rate reductions for standard offer services undercut the entry rate of new retailers. Standard offer service typically obliges the incumbent utility to provide fully bundled electric service at fixed or indexed rates for several years (e.g., during the transition period), usually following the introduction of retail competition. In some states, standard offer rates have been set so low as to discourage customers from switching to new entrant retailers, who must recover costs associated with setting up shop in local markets as well as the cost of purchasing energy in wholesale markets. Other states have established generation credits (so-called "shopping credits") for customers who no longer take power from the incumbent. In some cases, the credit exceeds the costs of generation that the incumbent avoids when a customer switches to a new supplier. While programs with high credits appear to be more successful in getting customers to switch suppliers, they do so by offering credits that bear no relationship to wholesale power costs or retail marketing costs.

In electricity markets with effective competition, consumers may have a greater number of options, both in terms of their supplier and the type of fuel used to generate electricity. Indeed, some states now require that all registered sellers generate a portion of their electricity using renewable supplies, such as solar, geothermal, and wind resources. However, because the cost of these resources is higher than conventional (fossil) fuels, a renewable portfolio standard raises the overall costs of power purchases. This forces higher costs on all electricity consumers.

Several polls suggest that consumers are willing to pay more for electricity generated by renewable energy resources. Some factual evidence supports these polls. A number of California customers selected a "green" power supplier when they switched suppliers. Customers in open states should be allowed to choose whether to purchase power from higher cost, renewable suppliers. An important but often overlooked low-cost, renewable resource is hydropower. Although new dam sites are not being proposed, existing resources could supply more electricity if steps were taken to streamline the burdensome re-licensing process and if additional resources were channeled toward increased research and development of more efficient technologies.

Some consumers can also supply their own electricity, using internal combustion and reciprocating engines, solar panels, and emerging technologies such as fuel cells and microturbines. This approach allows customers to generate electricity at its point of use, reducing, and in some cases eliminating, the need to use a traditional transmission and distribution network.

FUTURE DEMAND

Although the U.S. Energy Information Administration recently forecast that distributed generation will provide less than one percent of the nation's electricity requirements by 2020, a number of states are looking closely at interconnection standards for distributed generation, the design of appropriate rates for standby and backup services, and the recovery of interconnection costs (or any costs of additional facilities) required to accommodate a distributed generation unit. Regulatory policy should be competitively neutral with respect to distributed generation. Indeed, market-based price signals are the best approach to developing economically efficient investment in distributed generation systems.

POLICY ENVIRONMENT

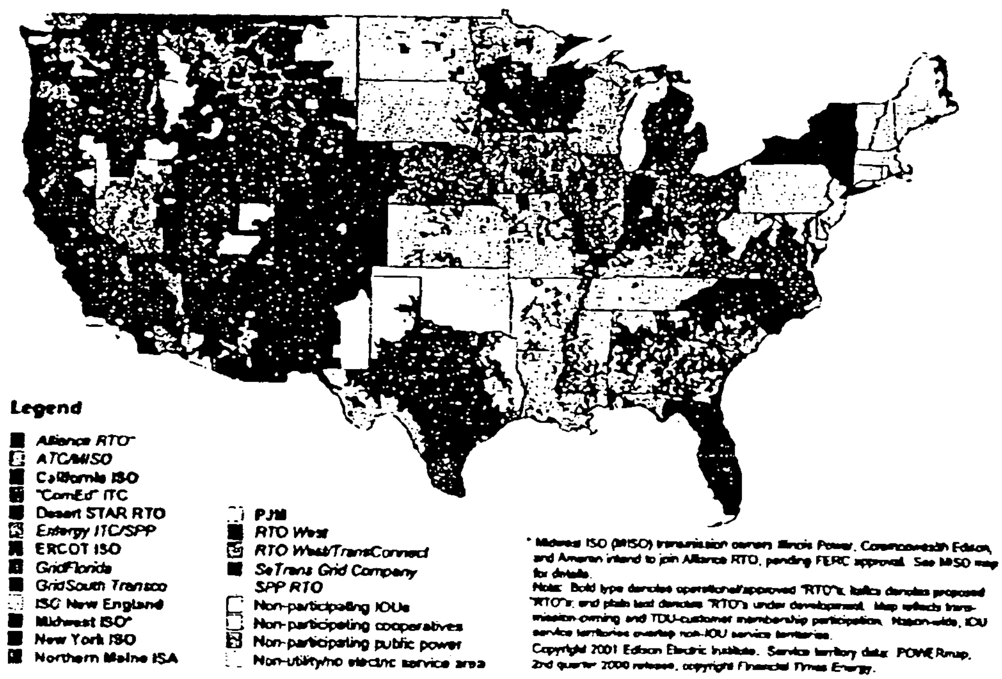
Seventeen electricity restructuring bills were introduced while the 106th Congress was in session. To date, no legislative package has gained consensus support, but significant issues embodied in many of these proposed bills are under serious consideration. For example, several bills propose the repeal of PURPA and PUHCA. Others would encourage state restructuring actions by resolving federal/state jurisdictional issues. Still others encourage the formation of regional transmission organizations (RTOs), including for profit transmission companies, propose resolving market power and transmission access problems, and/or the grandfathering of existing state restructuring plans to protect state plans from preemptive federal action.

Consensus has formed among publicly-owned and shareholder-owned companies in support of comprehensive tax legislation to facilitate fair electric competition. For shareholder-owned utilities, taxes that discourage the upgrades of distribution facilities would be eliminated. Moreover, the consensus agreement would defer taxes on the sale of transmission facilities, as well as eliminate taxes on the spin-off of such facilities. Both actions would stimulate the formation of independent RTOs. For public power utilities, the consensus agreement would modify private use provisions of the tax code, thereby encouraging these providers to open access to their transmission lines and also encourage them to participate in RTOs. Indeed, support is growing for broad tax legislation that would eliminate impediments to electric cooperatives interested in joining RTOs and opening their systems to competition.

There is recognition that critical bulk power system reliability issues need to be addressed. With the lead of the North American Electric Reliability Council (NERC), a broad consensus is being forged on reliability legislative language. Proposed legislation would extend FERC's authority for reliability (but not for economic regulation) to all segments of the U.S. electricity industry. This authority would ensure that all participants in electricity markets – independent power producers, distribution utilities, transmission utilities, system

Regional Transmission Organizations

Utility Participation as of January 2001



operators, power marketers, and customers –play by the same reliability rules and share equitably in the costs of reliability. At present, FERC has jurisdiction over only shareholder-owned utilities, which encompasses about two-thirds of the transmission facilities in the country. The proposed legislation would grant FERC the authority to approve and oversee one national electricity reliability organization. This organization, expected to evolve from NERC, will be responsible for developing, implementing, and enforcing mandatory reliability standards nationwide, with FERC oversight. Currently, compliance with NERC standards is voluntary, subject only to peer pressure. This new reliability organization will also have the authority to delegate certain responsibilities to regional entities, with approval from FERC.

The Role of the Federal Energy Regulatory Commission

In its role as overseer of wholesale markets and transmission, the Federal Energy Regulatory Commission has implemented the EPAct provision that modified federal laws in order to facilitate wholesale competition. Specifically, the Commission pushed wholesale competition forward in 1996 when it issued Order Number 888 and Order Number 889. In these landmark rules, FERC required the industry to provide comparable, non-discriminatory open access to the transmission grid and to unbundle generation, transmission, and ancillary service functions. The Commission also provided for recovery of wholesale stranded costs and established standards of conduct and methods to exchange wholesale market information on same-time electronic databases, known as OASIS. Recently, both FERC Orders were upheld in the Court of Appeals of the District of Columbia Circuit Court.

Moreover, in December 1999, FERC approved another landmark order promoting the development of regional transmission organizations (RTOs). Order Number 2000 calls for voluntary participation in RTOs. FERC stated its objective that all transmission-owning entities, including non-jurisdictional utilities, join RTOs. Order Number 2000 requires that RTOs be independent of market participants, serve a region of sufficient size and arrangement to maintain reliability, support efficient and non-discriminatory power markets, serve as the security coordinator for its prescribed region, and have exclusive authority over the maintenance of short-term reliability of its part of the grid, including the authority to redispatch generation resources.

Regional Transmission Organizations

FERC expects regional transmission organization to be operational by December 15, 2001. However, the establishment of RTOs is an arduous, time-consuming process that requires a satisfactory resolution of many contentious, critical issues among many interests. Several of the existing independent system operators (ISOs, one type of RTO) were developed from existing tight power pools; other RTOs will not have this advantage and will be more difficult and take longer to construct.

As of January 2001, 12 regional transmission organizations were in their formative stage. By the December 15, 2001 deadline, these entities are expected to manage the bulk power grid for over 85 percent of the nation's electricity consumers, based on current participation figures. Five independent system operators are already operational, and currently serve 33 percent of the nation's electricity consumers. An additional three such entities are approved, but are not yet operational.

Policy Challenges in the Transmission Sector

Over the years, U.S. electric utility companies, regulators and shareholders have built the most reliable electric system in the world. This record of achievement must not be tarnished during the transition to competitive power markets. The transition from an electricity industry that consisted primarily of regulated, vertically integrated utilities to one that emphasizes competitive markets for generation raises many concerns about reliability. Even though there is little evidence that overall reliability levels have changed in recent years, dramatic changes in the structure, operation, and regulation of the U.S. electricity industry require analogous modifications in reliability practices and institutions.

The current transmission system is comparable to the national highway system, a mix of two-lane state roads, multiple lane freeways, access roads, beltways and interchanges. Originally built to move limited amounts of power over relatively short distances, the electricity interconnections that were enhanced to bolster reliability created new opportunities to reach more distant customers, some in quite distinct markets. In today's increasingly competitive electricity marketplace, a greater number of suppliers are faced with bottlenecks and congestion because they often hit a two-lane road after having been on an eight-lane interstate highway, limiting the benefit of increased marketplace transactions. If more transactions are to be accommodated, more transmission facilities will have to be built or other means will need to be found to enhance the transfer capacity of the existing system. Otherwise, the expectation of lower costs for consumers may not be realized.

Most analysts agree that expansion of the transmission grids has not kept pace with growth in electricity demand. For example, annual investments in new transmission have declined by about $100 million a year during the past two decades. Moreover, between 1989 and 1998, the miles of transmission lines per MW of summer demand declined by 16 percent, and some projections show a further decline in transmission capacity of some 13 percent by 2008. [1]

The current focus on regional transmission operations may provide incentives to build needed transmission facilities. FERC has stated its receptivity to different forms of RTO structures including non-profit independent system operators and stand-alone transmission businesses (often referred to as TRANSCOs). Advocates of ISOs argue that transmission owners can, with relative ease, turn over control of their transmission assets to an ISO and that a non-profit ISO would more likely operate the system for the ultimate benefit of consumers. In contrast, TRANSCO advocates believe that the for-profit motive underlying their approach will result in improved performance and encourage the efficient expansion of transmission grids. For its part, FERC will consider new, innovative rate mechanisms such as performance-based rate making to meet the requirements of Order Number 2000, so long as commensurate benefits to consumers can be demonstrated.

KEY MARKET ISSUES

Challenges to Expanded Generation

The issue of expanded electricity generation—as well as the issue of transmission—will challenge policymakers in the years ahead. Certainly, electricity generation has not kept pace with consumer demand. Recent events of extreme price volatility and price spikes in light of record demand has made the need to preserve reliability a paramount concern. Generation reserve margins have been declining for at least the past two decades, at a rate of almost one percent per year. Currently, reserve margins are tight in some regions of the country, suggesting that additional generation is needed soon. While few utilities are planning to build much generation as part of their regulated rate base, unregulated utility affiliates and independent power producers have announced plans for more than 100,000 MWs of new capacity, more than enough to meet expected needs for the next several years. About 90 percent of new generators will be fired with natural gas. How much of this capacity will actually get built, and when, is not known, given the recent rise in natural gas prices. The key question is whether competitive market forces, when co-mingled with policies which restrict infrastructure expansion, will be sufficient to provide enough generating and transmission capacity to provide reliable power supplies for the U.S. economy.

Marketplace Dynamics

Existing independent system operators have experienced many difficulties in establishing and operating real-time markets for energy and reliability services. The California market in particular has been hampered by extreme price volatility and shortages. The problems in California point to need to design market rules and public policies, which jointly work to effect efficient market outcomes.

For example, existing markets are largely one-sided, with competition among generators but no competition between the supply and demand sides of the equation. Although volatile electricity prices contain important information for electricity consumers and suppliers that

[1] See "Electric Reliability: Potential Problems and Possible Solutions," Eric Hirst, May 2000.

can help maintain reliability, most consumers today continue to face time-invariant prices. Customers, especially large, sophisticated industrial customers, should have the opportunity to face time-varying (hourly) electricity prices and to participate in reliability markets (e.g., by offering to sell load reductions as contingency reserves). By allowing customers to voluntarily choose among multiple pricing products with varying degrees of price risk, the magnitude of the price spikes and overall system power costs can be substantially reduced. Even if only a small fraction of retail load chooses to face real-time prices, price spikes would be less frequent and dramatic, and the need for additional generating capacity would be reduced.

Because of the physics inherent in electric system operations, generation can be operated in a manner that can reduce potential transmission imports from other regions, block or interrupt sales by competitors, restrict generation output and raise prices, or inhibit construction of new, competing generation. Many industry stakeholders believe that the key to transitioning to competitive regional markets for wholesale power will require finely tuned market rules to eliminate the potential for gaming and to prevent the abuse of market power. They advocate market monitoring of the wholesale market and regulatory oversight to prevent market manipulation and consumer abuse, with potential abuses of market power investigated, mitigated and remedied.

BALANCING ELECTRICITY USE AND ENVIRONMENTAL CONCERNS

The U.S. electricity industry faces critical energy and environmental challenges in the coming decades. Electricity producers will be called upon to provide cost-effective and reliable power to fuel U.S. economic growth and an improved quality of life. Environmental regulators will face pressures to develop more efficient policies to meet well-established challenges—including targets for air and water quality—as well as new policies to meet emerging challenges such a climate change.

Environmental and energy policies sometimes conflict with one another. For example, efforts to improve urban air quality are not always consistent with efforts to lower electricity rates, or even to provide greater competition among suppliers. Although some conflicts represent inherent public policy tradeoffs, other conflicts can be avoided or reduced through more effective and efficient policy approaches. For example, potential air quality and climate change policies strongly encourage the development of natural gas, while policies restricting energy exploration and facilities siting would make production and use of natural gas more difficult. Policymakers engaged in developing a National Energy Strategy can reduce these conflicts by developing environmental policies that minimize the cost of achieving specific environmental objectives and by limiting inappropriate interference with market-driven fuel choices.

NUCLEAR POWER

OVERVIEW

The U.S. nuclear energy industry supplies about 20 percent of our nation's electricity. Behind this seemingly simple statement lies an extraordinary story. While nuclear powered electricity capacity has remained fairly constant, the amount of nuclear energy generation—which does not release air pollutants and is our largest source of emission free electricity—has increased significantly as U.S. demand for electricity has risen. The reasons behind nuclear power's success are many.

During the past decade, the efficiency, safety and reliability of operating nuclear plants have grown steadily and dramatically. The average capacity factor of the U.S. nuclear power fleet has increased over 16 percent since 1990 to 86.8 percent. This is the result of improved maintenance conducted in shorter and shorter refueling outages and longer intervals between refuelings. The result has been the effective equivalent of adding over 23 new 1,000 MW nuclear plants on line.

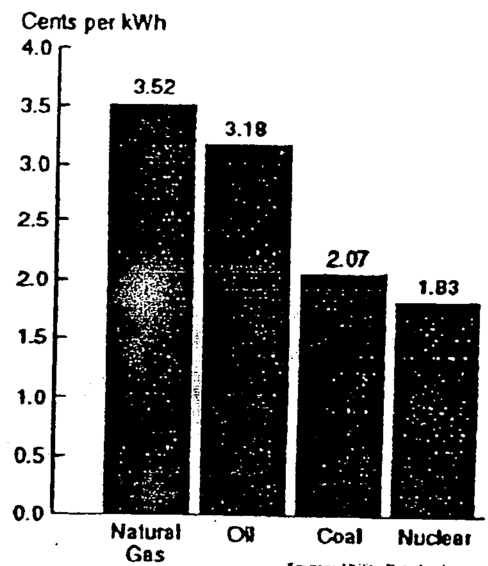
REGULATORY ENVIRONMENT

Under the careful oversight of the U.S. Nuclear Regulatory Commission (NRC), the regulatory environment for nuclear powered utilities has improved in the areas of operating safety and efficiency. Four decades of commercial nuclear operations have yielded a growing understanding of factors that influence operating safety. This experience has resulted in the revision of regulations and practices, making nuclear powered plants even safer than before.

Deregulation of the electric power industry also has sharpened the focus on safe, efficient operating practices. Industry restructuring has produced fewer nuclear power plant operating companies, but these companies include highly focused management teams able to provide consistent and reliable solutions improving efficiency and safety. Consolidation has also created new efficiencies in the administrative management of the nation's nuclear power plants.

These same trend lines have reduced overall operating costs. Today, the nuclear

Energy Production Costs in 1999



Source: Utility Data Institute

energy industry has achieved very competitive production costs, measured in cents per kilowatt-hour. At the same time, industry restructuring has recast fixed costs such that total electricity costs are highly competitive. Nuclear units across the industry can run at total costs of 2 to 2.5 cents per kilowatt-hour. Of this, the cost of nuclear fuel, including a charge for the ultimate disposition of the used fuel that all operators pay, is about one-half cent per kilowatt-hour.

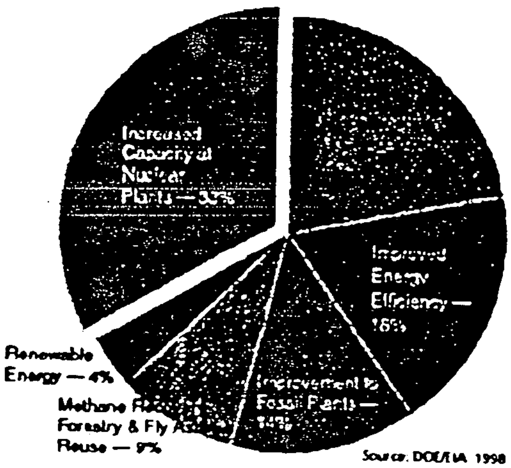
LICENSE RENEWALS

In March 2000, the NRC renewed the licenses for the two-unit Calvert Cliffs nuclear plant for an additional 20 years of operation beyond the 40 years originally licensed. Two months later the three-unit Oconee nuclear station received a 20-year renewal. These renewals recognize that conscientious operations and maintenance have sustained and improved the value of these plants. It is expected that almost all nuclear power plants will apply for and obtain a renewal license that adds 20 years to these facilities. License renewals further increase the competitiveness of nuclear powered electric utilities.

ENVIRONMENTAL ADVANTAGES OF NUCLEAR POWER

From an environmental point of view, nuclear energy offers several important advantages. Since the combustion process is not needed to produce nuclear energy, there is no adverse impact on air quality. This is an important environmental consideration. In 1999 the United States generated a record 728 billion kilowatt-hours using nuclear power. That production avoided the emission of 1.92 million short tons of NOx, 3.97 million short tons of SO_2 and 167.8 million metric tons of carbon, compared to the current mix of fossil energy resources. From a policy perspective, it is ironic that environmental credits are extended to energy producers that adversely impact air quality, but not to electricity generators, such as nuclear and hydro, that entirely avoid air quality impacts. Nuclear energy is the most significant source of CO_2 reduction through its increased production over the last decade in the voluntary program to mitigate carbon emissions.

Voluntary Carbon Emission Reductions



Indeed, if nuclear energy were not part of the nation's generating mix, most current clean air act standards—particularly those areas with large concentrated populations and heavy industrialization—would not be met. In areas of high density power use, the environmental benefits of nuclear energy can be leveraged to provide heating, cooling and transportation in the form of electrified rail and mass transportation. It is most efficient when operated at full power, 24 hours per day to supply base-line power needs. Nuclear energy is wisely used in a diverse combination with other fuels that use technologies well adapted to cycling or peaking loads. The presence of nuclear power plants in these areas of high electricity demand is a significant factor, which allows the siting of other emitting forms of generation while maintaining overall emissions within federally mandated levels.

URANIUM FUEL SUPPLY AND DISPOSAL

Uranium, the heaviest of all naturally occurring elements, powers nuclear plants. Nuclear reactors release energy by splitting uranium atoms. Since no combustion takes place during the generation of electricity from reactor fuel, air quality and the atmosphere are not affected. Once the nuclear reaction takes place, energy is transferred to turbines that generate electricity in a closed process. All waste products are retained in the solid fuel pellets and isolated from the environment.

Uranium is abundantly available in the earth's crust, both in North America and elsewhere, and the capability to extract ore and convert it to reactor fuel is available domestically. The primary, and almost sole, use of uranium is the production of energy. Robust supplies of reactor fuel can be made available from domestic sources without threat of international interference. Reactors can also consume the uranium and the man-made element, plutonium, which were produced as stockpiles for national defense purposes. Commercial reactors are being used to reduce the threat of nuclear proliferation using these inventories as fuel for the generation of electricity.

In recent years, the U.S. government has pursued policies aimed at consuming excess inventories of weapons grade uranium that had accumulated in the former Soviet Union. Such policies reduce the threat of nuclear warfare and spur international economic activity, but they also depress demand for U.S. mining, conversion and enrichment services. Indeed, U.S. businesses may become unprofitable and exit the market. The long-term impact of this possible threat to U.S. energy security should be examined closely by policymakers when they formulate a National Energy Strategy.

Some believe that the Achilles' heel of nuclear energy is the disposal of used nuclear fuel. However, this objection to its use is not based on facts. In the roughly 40 years of commercial nuclear operation in the United States, there has been no impact on the environment from used nuclear fuel. It remains at the power plants where it was used, fully accounted for, with no measurable impact on the environment. By act of Congress, a decision has been made to take central accountability for used nuclear fuel. Exercise of this option by the federal government when it is ready, will also result in negligible impact to the environment, according to federal studies. In the meanwhile, except in a few jurisdictions that have set artificial deadlines for the federal government to accept custody of the fuel, no major barrier exists to maintaining past practice of storing fuel where it was used, even though this does not represent the best public policy.

Moreover, once used fuel is deposited in a central repository, that site will become a strategic fuel reserve. Used nuclear fuel contains a high residual energy content, which can be recovered through reprocessing. Currently, U.S. policies do not allow the reprocessing of nuclear fuel, even though it is permitted elsewhere in the world. Reprocessing is not economical at the present time. If circumstances change, all fuel in the central repository could be reprocessed. In addition, future reactors can be designed to produce more fuel than they consume. This would make nuclear power a renewable energy resource.

COMPETITIVE COSTS

The abundance of uranium and the relatively low cost of converting it to reactor fuel mean that nuclear fuel costs are likely to remain stable for the next several decades. Moreover, the continued reliance on nuclear energy as part of the nation's diversified electricity portfolio should minimize price volatility in electrical markets. A stable price environment for energy means, in turn, that the overall U.S. economy should grow more efficiently.

Production of energy from nuclear fuel results in relatively high-energy yields per stable unit of fuel consumed. For example, one cubic inch of uranium 235 contains the energy equivalent of over 650 thousand gallons of oil, 3,300 tons of coal or 7 billion cubic feet of natural gas. Although there are environmental impacts from the extraction of uranium and speculative environmental impacts from the disposition of used nuclear fuel, they are relatively minimal because of the very small quantities of fuel required.

EFFECTIVE R&D AND INVESTMENT POLICIES COULD ENHANCE THE USE OF NUCLEAR POWER

Increased research and development could lead to discoveries that would improve operating efficiencies of current reactors, improve the design of future reactors and develop nuclear fuel sources that do not produce weapons material as a by-product. For example, small, transportable reactors have been designed for military use, but little work has been done to make these prototypes commercially viable. Such reactors could be put to a number of good uses, including water purification. An aggressive research program could ensure the availability and wise use of this emission free, abundant and compact source of energy.

Like other critical infrastructure systems, including railroads and highways, energy suffers from a lack of adequate capital investment. Nuclear energy is no exception. Currently, investors are not attracted to the modest return on most nuclear power plants, compared with the potential return on investments in information technology or other high technology industries. In the case of energy infrastructure, the issue is compounded by the perceived risk of investing in an industry sector that is undergoing deregulation and restructuring.

Eventually, of course, energy prices will rise to such a level that profits and return on investment in the energy industry will appear commensurate with other investment opportunities. The better approach, however, would be the creation of incentives for needed infrastructure investments in the near term. In the decades ahead, policymakers will need to devise policies that encourage investment while not interfering with free markets and the growth of competition within and among energy sectors. If such policy measures are not formulated and implemented soon, the likelihood increases that policymakers will have to respond to public outcries against high-energy costs by developing ill-conceived policies that do interfere with the market.

THE ROLE OF EDUCATION

The United States also needs to invest in an educated workforce that is capable of supporting the energy infrastructure that experts have forecast. This is not an easy task, both because the demand for skilled engineers and technicians is growing rapidly and because fewer and fewer students are pursuing courses of study that would prepare them for work in energy related industries. Indeed, enrollment is declining among institutions that offer such educational programs and degrees. Unless action is taken soon, the educational system may be unable to support the demand for energy that appears inevitable during the next decade.

Education also is needed to change the public's perception of nuclear energy. Understandably, that view is largely negative. The first demonstration of nuclear energy that commanded world attention was a bomb that yielded devastating results. The generation of electricity from nuclear fuel is physically very different from the technology required for destructive use, but the perceived connection between the two has been skillfully exploited by some to alarm the public and the political system for decades. An effective National Energy Strategy would address this adverse image by engaging every educational level, and by stressing the environmental and security benefits that the safe use of nuclear energy affords our nation.

SUMMARY

Nuclear energy has been a growing component of the energy mix in the United States for more than 40 years. No member of the public has been harmed by nuclear energy during this period. Moreover, public polls have shown for years that a substantial majority of the American public believes that nuclear energy is safe and beneficial. However, in follow-on questions, that same substantial majority incorrectly believes that, individually, they are in the minority in their support and confidence in nuclear power.

A National Energy Strategy needs to be developed that brings nuclear energy back into favor. After all, nuclear energy provides substantial environmental benefits while producing baseload levels of electricity. Because combustion is not required to release energy, no air pollutants are emitted into the environment. Moreover, because small amounts of fuel create large amounts of electricity, the extraction and disposal of nuclear fuels can be readily controlled and managed. Nevertheless, many environmental groups oppose nuclear energy, for reasons which are not clear to industry experts and scientists.

In time, some external pressures — global environmental concerns, high population densities, alternate uses for land and raw materials, or price volatility—and a heightened political grasp of the benefits of nuclear energy use will create an environment favorable to its increased use. Until that time, however, the nuclear industry will have to remain focused on activities that dispel public misconceptions about this energy resource.

Global pressures already are at work that will have an impact on the future of this industry. As energy demand increases, few developing nations will have the ability to manage this technologically complex energy resource. Developed nations such as the United States will need to adopt policies that ensure its safe use by other nations. Certainly the United States, which has led the world in the development of nuclear energy and is now reaping the environmental and economic benefits of this fuel, should provide for its continued global use in a responsible manner. The world remains hungry for energy and the countless economic, social and personal benefits from an adequate, reliable and affordable supply of energy.

ENERGY EFFICIENCY AND RENEWABLE ENERGY

OVERVIEW

In the portfolio of energy options for the 21st century, energy efficiency and renewable energy are two that have demonstrated their potential to significantly contribute to U.S. energy needs in a cost effective and environmentally friendly manner.

Diverse forms of energy efficiency are widely diffused throughout the U.S. economy. End-use efficiency improvements occur from the market penetration of process controls, thermal barrier technologies, and other design improvements in industrial, residential, commercial, and transportation equipment.

Supply-side improvements include advanced combustion/gasification technologies, combined heat and power stations, district heating and cooling, and more efficient power transmission and distribution technologies. Although micro-turbines and fuel cells have not yet had substantial market penetration due to high initial cost, they hold promise for future improvements in supply-side efficiency.

At the macroeconomic level, there has also been a shift in the share of Gross Domestic Product (GDP) from more to less energy intensive activities. Part of this shift is the result of the rapidly falling cost of information and information technologies.

Renewable energy options are also diverse. These resources may be converted into electricity, heat, or mechanical power. Renewably based electric generating plants may be connected to a central grid or freestanding. The resources from which renewable energy is extracted include:

- **Solar radiation** – Sunlight can be used to produce thermal energy for space and hot water heating, or electricity generated from either photovoltaic panels or high temperature solar collectors that produce steam to drive turbines. Diffuse radiation is available through the country, while direct radiation for concentrating collectors is strongest in the Southwest.
- **Running water** – The largest source of renewably generated electricity, hydropower, is harnessed by creating reservoirs or by installing run-of-river turbines. Future expansion of hydropower capacity is limited by resource constraints.
- **Wind** – Commercial wind-farms are sprouting up throughout the country with individual turbines as large as one megawatt. The largest wind resources are found in the midwest.
- **Biomass** – Woody and herbaceous materials can be burned directly for electricity or heat, gasified, or liquefied. In some cases, forest or agricultural residues are used; dedicated biomass feedstocks are grown for energy production.
- **Geothermal heat** – High temperature geothermal energy for large-scale power production is located primarily in the western U.S. However, low temperature heat from the earth is also used in "ground-source" heat pumps as a source of residential and commercial space conditioning.

Renewable Electricity Generating Capacity, 1999

Technology	Capacity in Operation (in MW)
Biomass	10,570
Geothermal	2,697
Hydro (includes pumped storage)	94,789
Photovoltaics	15
Solar Thermal	354
Wind	2,602

Source: "REPiS: The Renewable Electric Plant Information System" 1999 Edition, NREL

As of 1999, renewable electric generating capacity was about 111,000 Mw, mostly from large hydropower facilities.

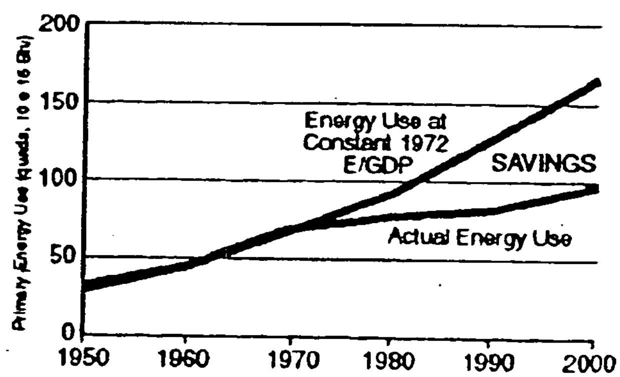
A key advantage offered by energy efficiency and renewable energy options is low environmental impacts, especially with respect to air emissions. Clearly, energy efficiency improvements and renewable energy will be essential to meet our energy needs.

TRENDS

Energy efficiency improvements have had a major impact in meeting national energy needs since the 1970s, relative to new supply. Energy intensity improvements are a combination of end-use efficiency improvements, supply-side improvements, and structural shifts in the economy toward less energy intensive sectors. If U.S. energy intensity (Quadrillion Btu per GDP) stayed constant since 1972, consumption would be about 70 Quads (74 percent) higher in 1999 than it actually was.

One of the drivers for improved energy intensity has been the implementation of appliance efficiency standards. The standards for different appliances came (or will come) into effect over the period 1988-2005. As more efficient models of appliances and equipment penetrate the market, they shift the overall efficiency of the nation's capital stock. Air conditioner manufacturers recently called for further improvements in efficiency.

U.S. Trends Shows Reduction in National Energy Intensity



Source: DOE/EIA

One recent exception to positive trends in end use efficiency is in the transportation sector, where average fuel economy of motor vehicles has been flat or deteriorating due to the increased sales of light duty trucks and 4-wheel drive vehicles and increased miles driven per vehicle.

Structural shifts in the economy have been away from manufacturing and toward the commercial and service sectors. Not only have knowledge-based sectors gained a larger share of our national GDP, the declining cost of information and communication services has allowed all sectors to substitute information for activities that use energy. Although office and network equipment constitute only a small fraction of U.S. electricity use, the digital economy requires a high level of power reliability, a characteristic that creates new opportunities both for energy efficiency in managing system load and for renewables in providing back-up power.

Renewable electric generation is projected to increase in absolute terms (from 389 billion kWh in 1999 to 448 billion kWh in 2020). At the same time, it is projected to decline in its share of the overall generation mix from 10.5 percent in 1999 to 8.5 percent in 2020, under business as usual assumptions (US Energy Information Administration, Annual Energy Outlook 2001, Market Trends).

COSTS AND COMPETITIVENESS

The cost of energy from renewable sources (notably photovoltaics and wind) has declined substantially over the past twenty years. These declines, however, have not necessarily made renewable energy competitive since the cost of competing energy sources has in some cases also declined.

Electricity industry restructuring has had a major impact on utility investment in energy efficiency and renewable power generation. Electric utilities have been a major source of investment in both end use efficiency (called demand-side management) and renewable electricity. Since the early 1990s, however, utility investment has diminished as competition or the threat thereof grew and regulatory mandates waned. At the same time, restructuring has been accompanied by falling reserve margins and concerns over system reliability, trends that may offer new opportunities for distributed supply and demand side resources.

Finally, certain global trends have implications for energy efficiency and renewables. In particular, developing countries are projected to make enormous investments in energy-producing and consuming capital stock during the coming decades. This long-lasting infrastructure will commit these countries to levels and types of energy use for decades to come thereby creating an excellent opportunity to improve developing country energy efficiency by utilizing new end-use energy technology.

POLICY ENVIRONMENT

Electricity Restructuring

The decision by policymakers to unbundle heavily regulated electric utilities while simultaneously introducing wholesale and retail competition into the U.S. electricity industry has thinned reserve margins, increased investment risks in new power generation, and increased price volatility. Under these circumstances, energy efficient practices and technologies (especially ones that can be targeted to specific times and locations) have added value. For example, some small-unit renewable energy technologies can now compete with conventional energy suppliers in geographic areas where the cost of conventional energy is high. Moreover, some power retailers have offered their customers the option of paying a bit more for power generated from renewable sources through green pricing and marketing initiatives. Policymakers should strive to ensure that compensation to distributed generation (DG) and combined heat and power (CHP) owners for sales back into the grid include payment of their fair share of the distribution systems they use, while eliminating unreasonable or unnecessary barriers to DG/CHP deployment. By preventing cost-shifting (e.g., from DG/CHP customers to other utility customers) policymakers can ensure that customers are encouraged to deploy DG/CHP where they are efficient.

Policymakers should take these trends into consideration when developing a National Energy Strategy. While energy efficiency practices do not generate additional electricity reserves, good energy management practices do extend the resources that are available. Policymakers can encourage such practices by ensuring that consumers face accurate time and location-specific price signals and have access to accurate information about the environmental implications of their energy use. Where necessary, policymakers should also implement initiatives that assist low-income consumers in paying higher prices and that overcome market barriers inhibiting all consumers from responding to energy price signals.

International Cooperation and Technical Assistance

U.S. security analysts are increasingly aware of global competition for fossil fuels and potential threats to the global environmental. The United States can diminish both risks by encouraging developing countries to use the most energy-efficient and clean technologies available. One way to do so would be through educational programs aimed at encouraging developing countries to utilize advanced U.S. energy technologies, energy management practices and market-based policies. The United States is also uniquely positioned to help emerging nations build energy capacity, institutional capacity and finance energy-related activities and services. Doing so could prove to be a cost-effective investment, both for the United States and emerging economies.

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CARE

Critical Issues

Mercury

EPA completed a study in March 1998 of hazardous air pollutants, including mercury, that may be discharged from electric utility steam generating units, but did not address the issue of whether new controls are appropriate. The agency subsequently entered into a settlement agreement with the Environmental Defense Fund whereby such a determination must be made by December 15, 2000.

While mercury is a known neurotoxin, EPA's insistence that current domestic exposures pose a public health threat is disputed by other federal agencies and is inconsistent with several recent scientific analyses. For instance, the Agency for Toxic Substances and Disease Registry has issued a mercury profile that is three times less stringent than EPA's proposed reference dose.

Key remaining questions are what level of mercury exposure is safe and what is an acceptable risk. EPA is currently requiring coal-based utilities to report on mercury content in coal and selected stack emissions. EPA also has included mercury on its lists of persistent bioaccumulative toxins, suggesting a desire to pursue mercury via water quality and waste-related impacts.

Separately, congressional appropriations language adopted in 1999 established an 18-month National Academy of Sciences study of mercury issues. The NAS is expected to conclude its work in the summer of 2000.

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Critical Issues

Ozone Transport - NO_x SIP Call Rule and State Petitions

The 1990 Clean Air Act Amendments created the Ozone Transport Commission to provide input to EPA regarding the control of NO_x and volatile organic compounds in regions of the country experiencing problems with high ozone levels. EPA subsequently established the Ozone Transport Assessment Group (OTAG) to produce a major NO_x control strategy for 37 states located east of the Rocky Mountains. Following the development of recommendations by OTAG, EPA in September 1998 proposed a state implementation plan (SIP) call rule under Section 110 of the Clean Air Act. This SIP call rule essentially required an 85 percent reduction in NO_x emissions from electric utilities in 22 eastern states starting in May 2003.

On March 3, 2000, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision substantially upholding most major issues in the SIP Call rule. Several states and industry groups have appealed to the full Circuit court. These parties also have requested that the court leave in place a "stay" of EPA's implementation of the rule, while the agency has filed a motion requesting that the "stay" be lifted. If EPA's motion is granted, the states and industry groups have requested further that the SIP Call implementation schedule be lengthened.

In a parallel proceeding, several Northeastern states filed administrative petitions under Section 126 of the act requesting that EPA (1) determine that specific out-of-state sources are adversely impacting air quality in the northeast, and (2) prescribe facility-specific controls. EPA announced in December 1999 that it was granting four state petitions, indicating that the agency agreed with the states' claims that they have difficulty meeting EPA's smog standard because of emissions from facilities in "upwind" states. The EPA decision would force 277 electric utilities in 12 states and the District of Columbia to meet strict new emission limits starting in May 2003. This action also has been challenged in the D.C. Circuit. Briefing has commenced, with final briefs scheduled to be submitted on November 6, 2000. Oral argument will occur late in 2000 or in early 2001.

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Critical Issues

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New Source Review/"WEPCo"/Coal-Fired Enforcement Initiative

The Environmental Protection Agency's New Source Review (NSR) requirements generally apply when companies, including coal-based electric utilities, build new facilities or reconstruct existing ones. Under the NSR rule companies are required to obtain permits that often necessitate the installation of stringent emission controls, including possibly "best available control technology."

EPA's pending revisions to the NSR program would revoke the so-called "WEPCo" rule. In the case of WEPCo, EPA found that "massive" and "unprecedented" work to replace numerous components at older generating facilities, including components that were not replaced at other units, was not routine. EPA officials noted that WEPCo's life extension project "is not typical of the majority of utilities' projects," confirmed that the WEPCo decision was not anticipated to have any impact on utility maintenance practices, and noted further they did not expect it to "significantly affect utilities" decisions to undertake power plant life extension projects. In contrast, however, EPA's new approach would subject to NSR review virtually any change at a utility that is intended to increase reliability, lower operating costs or improve efficiency.

At the same time, EPA and the Department of Justice are pursuing enforcement actions against owners of electric generating units that EPA alleges have circumvented the NSR rule in the past. Notices of Violation (NOVs) initially were issued for 32 individual facilities, and lawsuits were filed against 17 of these facilities. Additional NOVs and lawsuits have followed, and several states have also filed lawsuits alleging NSR violations. Ironically, these lawsuits came as EPA was negotiating with electric utilities over the definition of what maintenance functions could and could not be performed to keep power plants running reliably without triggering NSR review.

The current uncertainty surrounding the NSR issue must be resolved to ensure that coal-based electric utilities are able to perform routine maintenance to continue operating efficiently and safely.

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Release (43)

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House

Policy Agenda | House NDC | May 17, 2001

A 21st Century Energy Agenda

New Democrats want to meet our energy challenge with a progressive energy policy, one that embraces and invests in the technologies of tomorrow, spurs our people and our businesses to innovate, empowers consumers to make smart energy use decisions, and modernizes our often-outdated systems of regulations and infrastructure to fit the realities of the 21st century.

The choice is not between environmental protection and a strong economy. The choice is between returning to the outdated policies of the past, or recognizing the new landscape of the future: that our country can and must invest in the energy technologies that can supply the world with sustainable energy and modernize our regulatory and infrastructure systems that govern the energy market. New Democrats believe the choice is clear, and we look forward to working with our colleagues to develop an energy policy for the 21st Century.

A comprehensive and balanced energy plan is critically important to the strength of our economy. The United States already consumes a disproportionate share of the world's energy, and demand is expected to continue increasing in this country and, undoubtedly, around the rest of the world as their economies grow. As long as we are dependent on oil, we will be dependent on foreign sources. Natural gas and coal are also finite fossil fuel resources. While these traditional fossil fuel sources will continue to be key in our energy policy, we believe that greater energy efficiency and new sources of energy must be aggressively pursued for the sake of our economy, our environment and health, and for future generations.

We believe this challenge can be an opportunity. For years, regions with vast oil fields -- such as the Middle East or Mexico -- have supplied the world with energy. The innovative spirit and creativity of Americans gives us an opportunity to supply the world with the clean, renewable, and sustainable energy that we need -- if we pursue an energy policy for the future, instead of one from the past.

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Improving Fossil Fuels and Developing Sustainable, Reliable and Diverse Energy Sources:

We must seek to expand and diversify our energy supply to ensure the continued economic growth of our country. We recognize that traditional fossil fuels and natural gas are a critical part of our energy supply – in fact, during the eight years of the Clinton Administration, the federal government operated oil, gas and coal leasing programs that exceeded production levels during the Reagan and Bush years - and will continue to be so well into the future; however, our proposal does not endorse opening the Arctic National Wildlife Refuge or the protected coastlines of Florida and California to oil drilling. We believe expanding deployment of wind, solar, and other renewable power sources will not only make for a cleaner energy supply, but it will also stabilize prices, increase energy independence, and ensure reliability. We must also aggressively invest in long-term research and development to ensure the success of our energy technologies of tomorrow. Some of our ideas include:

Fossil Fuels and Nuclear

1) continued responsible drilling on federal lands and water, review royalty lease laws, and work to ensure oil and gas are as productive, efficient and clean as possible

2) increase funding for research and development to ensure coal production is as clean and efficient as possible CCT

3) accelerate depreciation on capital investments to improve generation and for investments to increase efficiencies and improved pollution controls at refineries

4) ensure nuclear re-licensing takes safety, cost effectiveness, and energy needs into account

5) continue full funding for nuclear waste and safety research

Renewable and Clean Energy Alternatives

1) enact a renewable energy generation tax credit for the investment, installation, and generation of wind, solar, biomass (open and closed loop), incremental hydro, fuel cells, landfill, and geothermal for resident, business, and generators, allowing for credit trading

2) double research and development funding for all renewable energy programs

3) increase research and development funding and incentives for use and development of alternative fuels, including ethanol, methanol, and biodiesel

4) create grant program for schools, hospitals, libraries, and other non-profit entities for installation and use of renewable energy sources

5) require the federal government to purchase a certain percentage of its power from non-hydropower renewable sources

6) creation of a Federal Energy Bank to provide loans to state and

federal agencies for investment in installation and generation from renewable energy sources, modeled after the successful Texas program

7) accelerate depreciation for large energy users to invest in the production of self sufficient renewable generation, and accelerate depreciation for certain capital expenses to increase the installation of renewable forms of energy

II. Efficiency and Conservation

Lowering Prices for Consumers Now and Extending the Life of our Energy Supply:

We can increase our energy productivity by promoting energy efficiency and conservation. Increased energy efficiency has already significantly reduced our demand for imported oil and new power plants. For example, in 1974, we consumed 15 barrels of oil for each $10,000 of GDP; today, we only consume 8 barrels of oil per unit of GDP. Research and development, tax incentives, and high efficiency standards can all help us do more with less. What's more, we will simultaneously reduce costs for consumers and businesses and prolong the life of our energy supply. Some of our ideas include:

Power Plants

1) tax credits and regulatory relief for the installation of co-generation on existing generation facilities

2) tax credits for energy-efficient and environmental improvements for coal plants

Vehicles

1) increased mandatory vehicle efficiency standards for all cars, light trucks, minivans, and sports utility vehicles

2) continued full funding for the private-public partnerships to develop more efficient and low and zero emissions vehicles

3) mandatory purchase and use of a federal fleet of energy-efficient and alternative fuel source vehicles

4) consumer tax credit for energy-efficient, low and zero emission, and alternative fuel vehicles

5) develop a more uniform fuel standard, including diesel, to reduce refinery bottlenecks and mitigate effects for small and independent refiners.

Efficiency Standards

1) comprehensive review of all government facilities to increase energy efficiency and implement private energy-performance contracts to upgrade buildings

2) mandate all new federal facilities meet highest building efficiency

standard and aim to be self-sufficient with renewable energy

3) enactment of proposed new air conditioner standards

Residential and Commercial Incentives

1) creation of a low interest loan program for high level energy

1 | 2

(44)

PGE

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8401 • Fax (503) 778-5566

Peggy Y. Fowler
CEO and President

March 5, 2001

Mr. Joe Kelliher
Senior Advisor to Secretary Abraham
Department of Energy
1000 Independence Ave., SW
Washington, D.C. 20585

Dear Mr. Kelliher:

Enclosed is a summary of what Portland General Electric believes should be changed in the hydro relicensing process. You may find this useful in some of your work.

We are continuing to work on specifics of suggestions around the Bonneville Power Administration. I may send you some ideas in the future. I did include a piece by David Piper of PNGC, that summarizes many of the same opinions we have about BPA issues.

Sincerely,

Peggy Fowler

Enclosures

Recommended Changes in Hydro Relicensing Process

Congress recognized last year the need to make the hydro relicensing process shorter and more rational and asked FERC to describe the necessary changes; FERC's report is due in May. In addition, the hydro industry, including Portland General Electric Company (PGE), is promoting legislation that was introduced by Larry Craig (R-Idaho) last year and reintroduced this year. The following are the specific changes PGE recommends be made or considered.

- Reform mandatory conditioning authority. Many agencies, state and federal, have the ability to tell FERC to include terms and conditions in a license. While repeal of the portions of the Federal Power Act granting such authority is desirable, a more widely acceptable alternative would be to (1) require agencies to abide by deadlines, (2) require agencies to consider economics and peer reviewed science in their decisions and (3) create an administrative process for review of terms and conditions proposed by agencies. This last item is important because FERC won't deal with the conditions, which then leaves only the federal court of appeals as a venue for review. The Court of Appeals is ill suited to these types of disputes, which most often are disputes about the facts.

- Improve coordination between NEPA and other processes (Clean Water Act, Endangered Species Act, CZMA, and Section 106 consultation) FERC puts the environmental review required under NEPA at the end of the relicensing process. By then a licensee has likely spent several years gathering information and doing studies. If FERC determines in its NEPA review that the information is insufficient or that the wrong studies were done, the process essentially starts over. Time and money can be saved if FERC starts its environmental review at the beginning of the relicensing process. Also, other agencies should be required to participate in FERC's NEPA review as "cooperating agencies" rather than undertaking their own separate reviews. Lastly, all of the disparate processes should be coordinated whether or not they require a NEPA style review. One suite of studies could be designed that would suit all purposes, rather than doing one round for FERC, one for ESA compliance, one for Section 106 consultation on historic resources, etc.

- Increase funding of the relicensing process: Most agencies that participate in licensing have difficulty committing staff and budget to participate appropriately. This results in a tendency to positional bargaining and standard, rather than project specific, demands. PGE supports increased agency funding for participation in hydro relicensing. We also recommend reform of the current FERC fee system under which licensees pay for federal resource agencies' time and expense of relicensing, but the collected funds go to the general treasury, not to the resource agencies.

- Enforce deadlines Although FERC has the authority to do so, it has grown reluctant to enforce deadlines. Disciplined participation by all is critical to keeping the process moving, and direction from Congress to FERC is necessary to achieve this.

- Consider licenses without defined term of years Because licenses are issued for terms of 30 –50 years, many agencies and conservation group representatives treat relicensing as their sole opportunity to protect their interests. While PGE finds value in 30-50 year terms and appreciates that many in the hydro industry consider them absolutely necessary, we nevertheless believe a more reasonable model might be the one used for gas projects in which the underlying permit or site certificate is not time limited, but some of the component permits have to be renewed at relatively short intervals. This approach could provide agencies and conservation group representatives to accept more balanced solutions to natural resource decisions, knowing that if the solutions do not work there will be reasonable opportunities to revisit the issues.

THE OREGONIAN ◆ THURSDAY, MARCH 1, 2001

Commentary

BPA must stop trying to be all things to all people

The power marketing agency needs to take steps to live within its generation means

By now we all know that the safe, predictable energy world many of us grew up in has been replaced by a reality that features power supply shortfalls and volatile prices.

But isn't the Northwest supposed to be blessed with ample hydroelectric power? Isn't the Bonneville Power Administration a sturdy ship that will withstand the rough seas to deliver the Northwest to a safe (and economically manageable) destination?

Unfortunately, right now the answer is no, because the BPA doesn't have the resources to serve everyone who is asking for power.

◆ Consumer-owned utilities, which have statutory rights to federal power from BPA, are using more than ever.

◆ To quiet discontented public utility commissions, BPA has also offered to sell power to investor-owned utilities to help meet their residential customer needs.

◆ The metal workers' unions put the strong-arm on the Clinton administration and secured contracts so that BPA would continue selling to large industrial customers.

All these demands have resulted in sales of more power than BPA has in its supply — and now it is more than 2,500 megawatts short. At today's astronomical prices, about $200 per megawatt/hour, the shortfall BPA must make up adds up to approximately $5 billion annually. Five billion dollars that comes directly from wholesale rate increases, sometimes virtually doubling a customer's annual retail electric expenses.

IN MY OPINION

Dave Piper

It's a sure bet retail customers will not be amused. For residential customers and struggling businesses, rate increases of that magnitude can be financially catastrophic. Unchecked power costs could cause businesses to go bankrupt and jobs to be lost, triggering a domino effect that impacts consumers and the region's economic well-being.

In addition, if BPA can't collect enough in revenue to meet outstanding expenses it could miss its annual debt payment to the U.S. Treasury, engendering vigorous political assaults from budget hawks and envious Californians alike.

By trying to be all things to all people BPA has put itself on the brink of disaster.

So now what? Some immediate actions can help avert a tragedy.

First, to deal with BPA's current over-extended power sales, it should buy out certain customer contracts, helping them find alternative power sources. By negotiating specific customers such as aluminum companies and other energy-intensive "direct service customers" off its system, BPA saves money by reducing its service loads.

Second, once BPA's loads have been reduced, customers must take responsibility for meeting their portion of any remaining shortfall. If there are individual BPA customers that aren't geared up to handle their own energy purchases, they can continue to rely on BPA, bearing the costs incurred.

Finally, now and in the future: BPA should not sell more power than it has.

In fact, BPA should not build or buy any more long-term power resources at all, but instead be content to allocate power only to its remaining customers and summarily get out of the business of guessing what future electric demand will be. This tactic would eliminate future financial risk.

A plan to save both BPA — and the Northwest's access to the power resources it markets — can only happen through the collective support and active engagement of the Northwest's congressional delegation, the region's governors and the customers and interest groups that do business with Bonneville every day.

The "USS Bonneville" is a ship that can be righted. A more stable energy future is within reach through a sensible, strategic plan. It's time to grab buckets and begin bailing.

◆

Dave Piper is president and CEO of PNGC Power, a Portland-based electric power services cooperative owned by 15 Northwest electric distribution utilities.

APPA

(40)

American Public Power Association

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April 11, 2001

Mr. Joe Kelliher
Senior Policy Advisor to the Secretary
Department of Energy
Forrestal Building, Room 7B-252
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Mr. Kelliher: Joe

In meetings with the American Public Power Association's (APPA) Executive Committee and others in recent weeks, you have expressed your interest in receiving input on various aspects of energy policy from industry stakeholders. With that in mind, APPA has developed three position papers offering suggestions on renewable energy usage and greenhouse gas emissions, hydropower, and landfill gas-to-energy projects.

At your request, these papers are one page in length and therefore provide pared-down overviews and recommendations on each topic. I hope you will not hesitate to let me know should you need any additional information or should you have any questions or comments on these issues.

Thank you for your interest.

Sincerely,

Joe

Joe Nipper
Senior Vice President, Government Relations

Attachments

Hydropower: An Undervalued Energy Resource

Overview: As lawmakers address the energy crisis in California and elsewhere, all agree on the need to bring additional sources of electrical capacity online. Often overlooked is the need to preserve existing hydropower capacity, a clean, low-cost and reliable energy resource. In the West, 25,000+ megawatts (MW) of non-federal hydroelectric capacity is declining as a result of a lengthy, costly, and burdensome Federal Energy Regulatory Commission (FERC) hydroelectric licensing process; a process that also restricts development of new hydropower capacity. Nearly 30,000 MW of new capacity could be developed from the 5,677 sites that exist.

Background: Hydropower represents about 10 percent of the nation's electricity and about 80 percent of its renewable energy. Overall, 98,200 MW of clean and efficient power is produced from these facilities – enough to power 98 million homes. In addition to its energy contributions, hydropower provides other important benefits such as irrigation, transportation, water supply, and recreation. Also, hydropower is important to the management of the nation's electric grid. As a fast and flexible generation source, hydropower can meet peak power demands and restore service after a blackout. Hydropower's ability to go from zero power to maximum output quickly and predictably makes it exceptionally effective at meeting changing loads and providing ancillary electrical services.

The Urgency: Despite these benefits, our nation is losing crucial megawatts of hydro capacity as a result of the FERC hydroelectric licensing process. In the decade following 1987, nearly 10 percent of hydroelectric peaking capacity was lost during project relicensing – a capability that must be replaced by less efficient generation sources.

- Hydro capacity to be relicensed: Over the next 15 years, roughly half of all non-federal hydroelectric capacity (nearly 29,000 MW of power) must go through the FERC licensing process. This includes 240 projects in 38 states.
- Capacity at risk: The excessive costs, delays, and conflicting mandates inherent in the licensing process could result in the loss of 1,200 or more MW of generation capacity in the Western region alone. On the other hand, with changes to the licensing process, and the proper financial incentives, another 10,415 MW of new capacity could be developed in the region without building a single new dam.

Conclusion: Substantive and meaningful improvements to the hydro licensing process are needed now. Such reform should include:

1. Balance into the FERC licensing process;
2. Consistent, objective administrative review procedure for mandatory conditions, including an opportunity for a hearing on the record if there is a disputed material issue of fact;
3. Mandatory conditions be supported by sound science;
4. Codification of existing FERC deadline authority for the submission of draft and final mandatory conditions;
5. Option for applicant to prepare a draft EIS under NEPA; and
6. Coordinated NEPA review with FERC as lead agency.

Separately, provide financial incentives to spur development of hydropower capacity at existing sites. Such incentives should provide comparable treatment to all tax paying and non-tax paying hydropower owners and operators.

Landfill Gas-to-Energy Projects – Providing the Mutual Benefit of Energy Production and Greenhouse Gas Reduction

Landfills have the potential to be an important source of energy and are a major source of methane – one of the most potent greenhouse gas (GHG). If captured, this gas, which is 21 time more potent than carbon dioxide, has the potential to be a sustainable source of energy that actually reduces greenhouse gas emissions.

Problems and opportunities: Landfills are the largest single human source of methane emissions in the United States (USEPA 1993). In 1995, landfills emitted over 11.1 million tons of methane gas. Based on methane's higher heat trapping potential, the level of methane emission is equivalent to releasing over 233 million tons of carbon dioxide (CO2) into the atmosphere or 56 million metric tons carbon equivalent – almost 5% of the net annual CO2.[1]

There are over 300 landfill sites that use technology to capture or use the emitted gas. These projects developed primarily because of the existence of a federal tax credit for development of non-conventional fuels. If the expired tax were reinstated or new incentives were developed for projects that use the gas for electricity, communities with landfills could benefit from a new stream of revenue from the sale of gas or electricity from the projects and the nation as a whole would benefit from the reduction of a critical greenhouse gas.

Landfill gas to energy project inventory and potential *(USEPA analysis of 31 states)*

- 317 LFGTE projects already exist and 54 are under construction;
  - Of these projects, 195 are on private landfills and 176 are on public landfills;
- The EPA has already identified 561 undeveloped landfills that could produce economically viable LFGTE projects;
  - Of these, 241 are privately owned and 320 are publicly owned;
- *New LFGTE projects could add 1741 MW of new capacity;*
- *New LFGTE projects could produce 15.2 million MWh of electricity annually*
- All landfills with over 2.5 million megagrams of capacity that emit 50 or more megagrams of landfill gas must flare the gas and would not be eligible as a source of alternative energy.

Potential to reduce GHGemissions through landfill gas-to-energy projects:

Landfills:

- produce approximately 56 million metric tons carbon equivalent (mmtce) each year;
- represent approximately 3 percent of all human sources of greenhouse gas emissions;
- that have developed LFGTE projects remove over 12 mmtce of methane annually;
- could develop LFGTE projects to remove much of the remaining 56 mmtce of methane.

[1] Electric utilities in 1999 emitted approximately 523 million metric tons of carbon equivalent, accounting for about a third of all human induced carbon emissions.

Reducing Greenhouse Gases by Enhancing Fuel Diversity

Background

Between 2001 and 2020, utility electricity production is expected to increase by 26 percent. Since the United States is reliant on coal to generate over 50 percent of its electricity, this high demand will result in an increase in carbon emissions. As was recently illustrated by James Hansen of NASA's Goddard Institute for Space Studies, the technology needed to mitigate carbon emissions will not be available for 30 to 50 years. The American Public Power Association (APPA) believes that a more workable approach would be to shift the emphasis from reducing just carbon emissions to reducing all GHGs, particularly those GHGs that are also pollutants like NOx and carbon black. This comprehensive, realistic approach would involve increasing fuel diversity, improving generation efficiency, enhancing energy conservation, and promoting clean fuel technologies.

Recommendations

Several policies could be pursued which complement a sound energy policy and also mitigate GHGs:

- Create Incentives to Increase Renewable Energy Usage. Renewable fuels add to energy diversity and are proven to reduce three GHGs: CO2, NOx and carbon black. Although there is enormous potential for renewable fuel usage, the technology necessary for widespread implementation remains cost prohibitive.

- Increase landfill gas-to-energy projects. Landfills are the largest human source of methane emissions, which are 21 times more potent than CO2 emissions. Capturing and using methane for energy production by increasing and improving landfill-to-energy projects will result in significant air quality benefits.

- Encourage generation efficiency programs which do not increase pollutant emission rates. For example, a 5% increase in turbine efficiency will increase electric output by the same amount with no increase in pollutants or GHGs. In order to encourage more efficient generation, however, the Environmental Protection Agency's new source review rule will have to be reevaluated.

- Encourage projects which enhance, restore, or increase output from existing hydropower facilities. Each time a hydropower project is relicensed, an average of 8 percent of capacity is lost. By streamlining relicensing and enhancing hydropower capacity, electrical outputs will increase with no resulting increase in air pollutants or GHGs.

- Expedite the reduction of emissions from older, uncontrolled fossil-fueled power plants. The resulting reduction of NOx and carbon black will significantly lower GHG emissions.

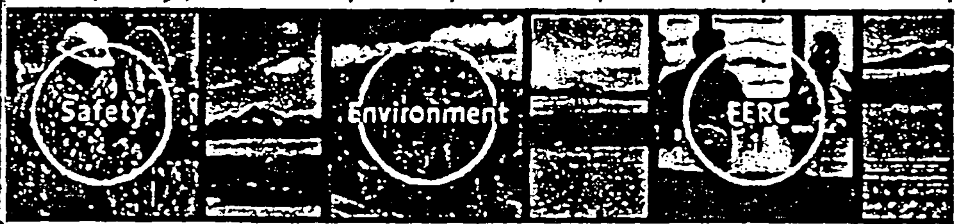
- Encourage the rapid development of clean coal technologies and the exportation of these technologies, especially to developing countries. This type of effort will illustrate America's commitment to reducing GHGs – particularly CO2 – globally.

Conclusion

A national policy should advocate and encourage a reduction in the growth of GHG emissions. The same principle that is being used to develop a federal budget framework should be used to reduce greenhouse gases. A national policy should focus on decreasing the growth in GHG emissions rather than cutting the baseline. These decreases should be workable and attainable through largely voluntary methods.

(46)

Interstate Natural Gas Association of A



INGAA

- INGAA Action Plan for 2001

Pipeline Safety

INGAA is actively pursuing a pipeline safety program that promotes greater knowledge of the industryÕs excellent safety record and controls unnecessar and legislation. INGAA will:

- Continue to pursue natural gas pipeline safety integrity rules that are ra effective and flexible;
- Provide input on a community outreach rule that assures the public tha pipelines are safe, and to incorporate efforts pipelines already use;
- Use the Internet to inform the public on pipeline safety; and
- Work to assure that any congressional actions to legislate pipeline safe sense and are cost-effective.

The Environment and Climate Change
INGAA will:

- Develop an industry proposal for more efficient and cost-effective eng permitting requirements at the Environmental Protection Agency;
- Continue to evaluate emissions plans for electric generators and advoc natural gas can contribute as a strategy option;
- Promote the co-firing of coal and natural gas for generating facilities a emissions reduction; and
- Continue to monitor climate change hearings and discussions, focusing requirements that would increase natural gas use.

MARK D. NELSON
VICE PRESIDENT
FEDERAL RELATIONS

American Chemistry Council Good Chemistry Makes It Possible (47)

April 27, 2001

The Honorable Joe Kelliher
Senior Advisor to the Secretary
Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Kelliher:

Fred Webber, President and CEO of the American Chemistry Council, recently wrote Secretary of Energy Spencer Abraham to inform him of the continuing progress by Council member companies in improving their energy efficiency and reducing the carbon intensity of their manufacturing operations. These trends, of course, are highly relevant in the context of the current debates about energy policy and global climate policy and directly support national objectives.

Because of your interest in these issues I am pleased to provide you with a copy of Mr. Webber's letter. If you have questions please call me or call Thomas Parker, Jr. at 703-741-5916.

Sincerely,

Mark Nelson

Attachment: Fred Webber letter to Spencer Abraham, April 26, 2001

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FREDERICK L. WEBBER
PRESIDENT AND CEO

American Chemistry Council Good Chemistry Makes It Possible

April 26, 2001

The Honorable Spencer Abraham
Secretary of Energy
Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Secretary Abraham:

Because of the intense current interest in national energy policy and global climate change policy, I am pleased to tell you about the summary results of the American Chemistry Council's 1999 Energy Efficiency and Greenhouse Gas Emissions Survey and our 1999 Energy Efficiency Awards Program. Both activities are part of the Council's voluntary Energy Efficiency Continuous Improvement Program and Climate Action Program and are directly relevant to national energy policy and global climate change objectives.

The business of chemistry is a major consumer of virtually all types of energy – fuel, power, steam and feedstocks (raw materials) for our processes. Chemistry companies are driven by competition, economics and a strong sense of environmental stewardship to continually improve energy efficiency. The results documented by these Council voluntary programs demonstrate how our members contribute to shared national and industry goals of great importance, specifically improved energy efficiency and strengthened international competitiveness; conservation of energy resources; and, reduction of energy-related and other greenhouse gas emissions.

I. The 1999 Energy Efficiency and Greenhouse Gas Emissions Survey. The survey results indicate that the business of chemistry continues to improve its energy efficiency and CO_2 emissions performance. Summary data from the survey are in **Attachment 1** to this letter. Highlights are as follows:

1998-99 Energy Efficiency & CO_2 Emissions Trends. The sample group of forty-eight Council member companies that responded to the survey in both 1998 and 1999 had, in the aggregate, 1999 sales of approximately **$109.2 billion** and non-feedstock energy consumption of 2.019 quads. **Energy efficiency performance for this group of companies over this period, measured as Btus per pound of production, improved 1.2%. Carbon dioxide emissions, measured as pounds of CO_2 per pound of production, declined 1.4%.** (These CO_2 emissions include emissions from purchased electricity.) **Absolute CO_2 emissions for this group of companies,** again including emissions from purchased electricity, **increased 1.6%, but this increase was much less than the increase in constant dollar value of sales (5.3%) and pounds of production (3.0%).**

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