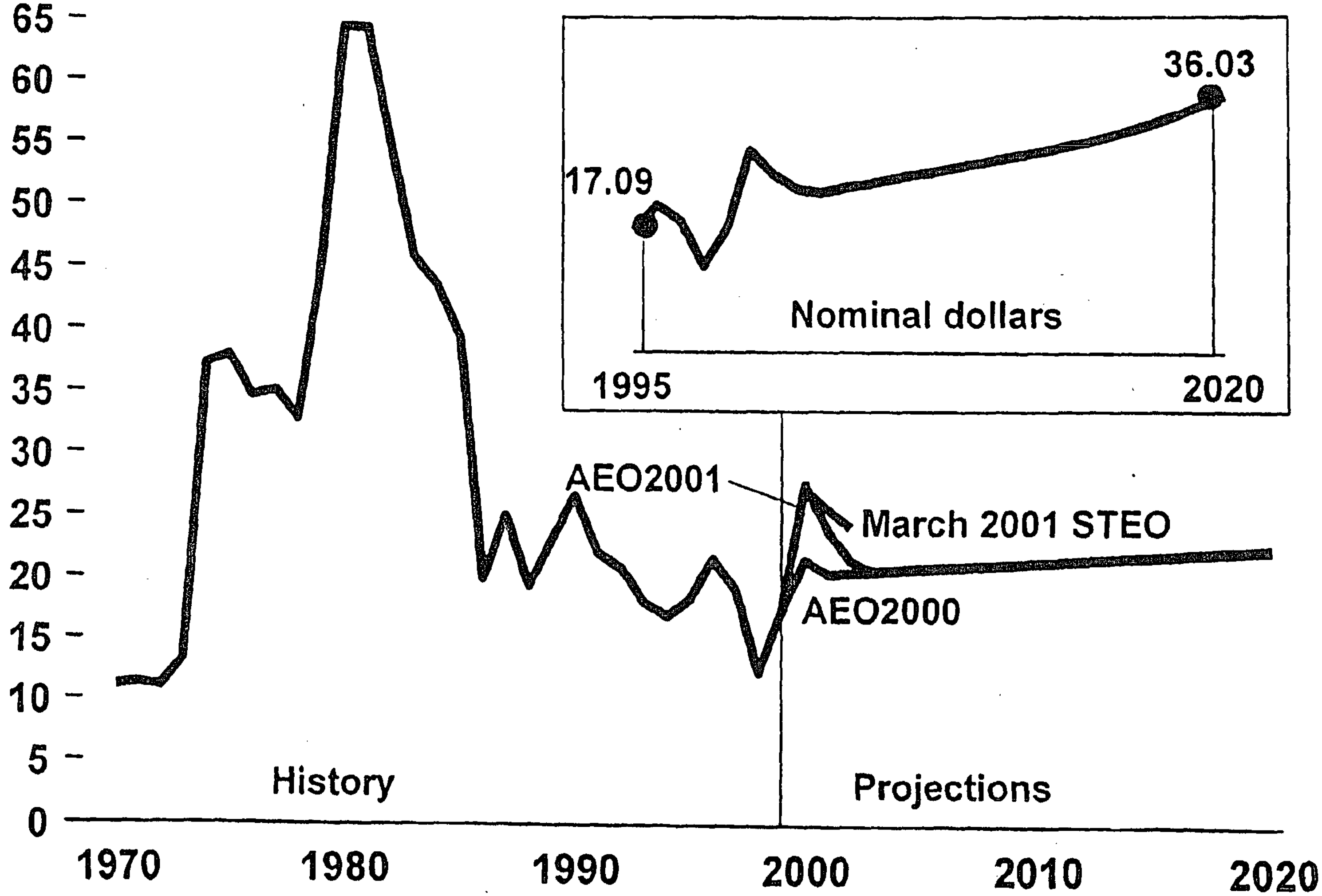
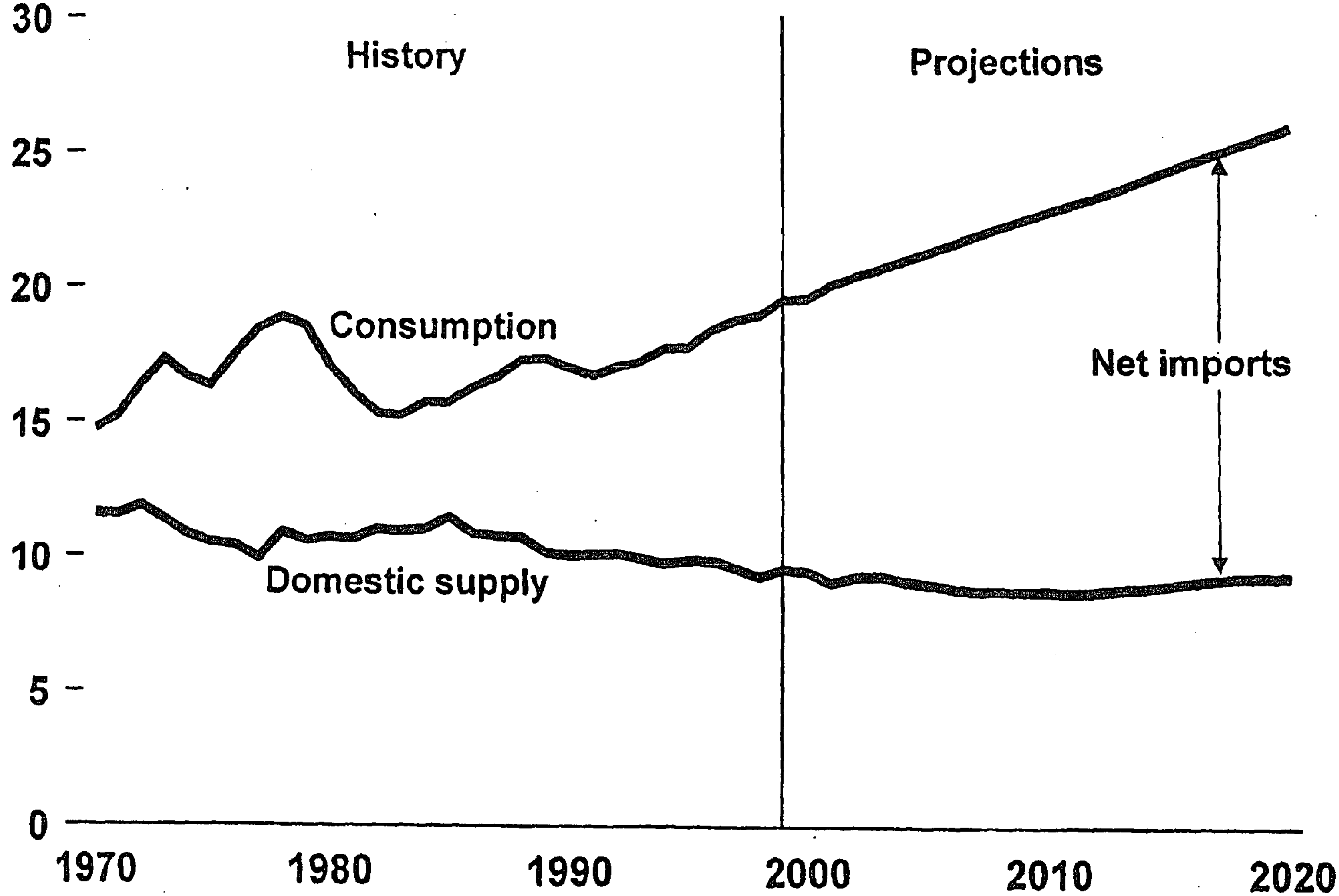
World Oil Price, 1970-2020
(1999 dollars per barrel)



Petroleum Supply, Consumption, and Imports, 1970-2020 (million barrels per day)



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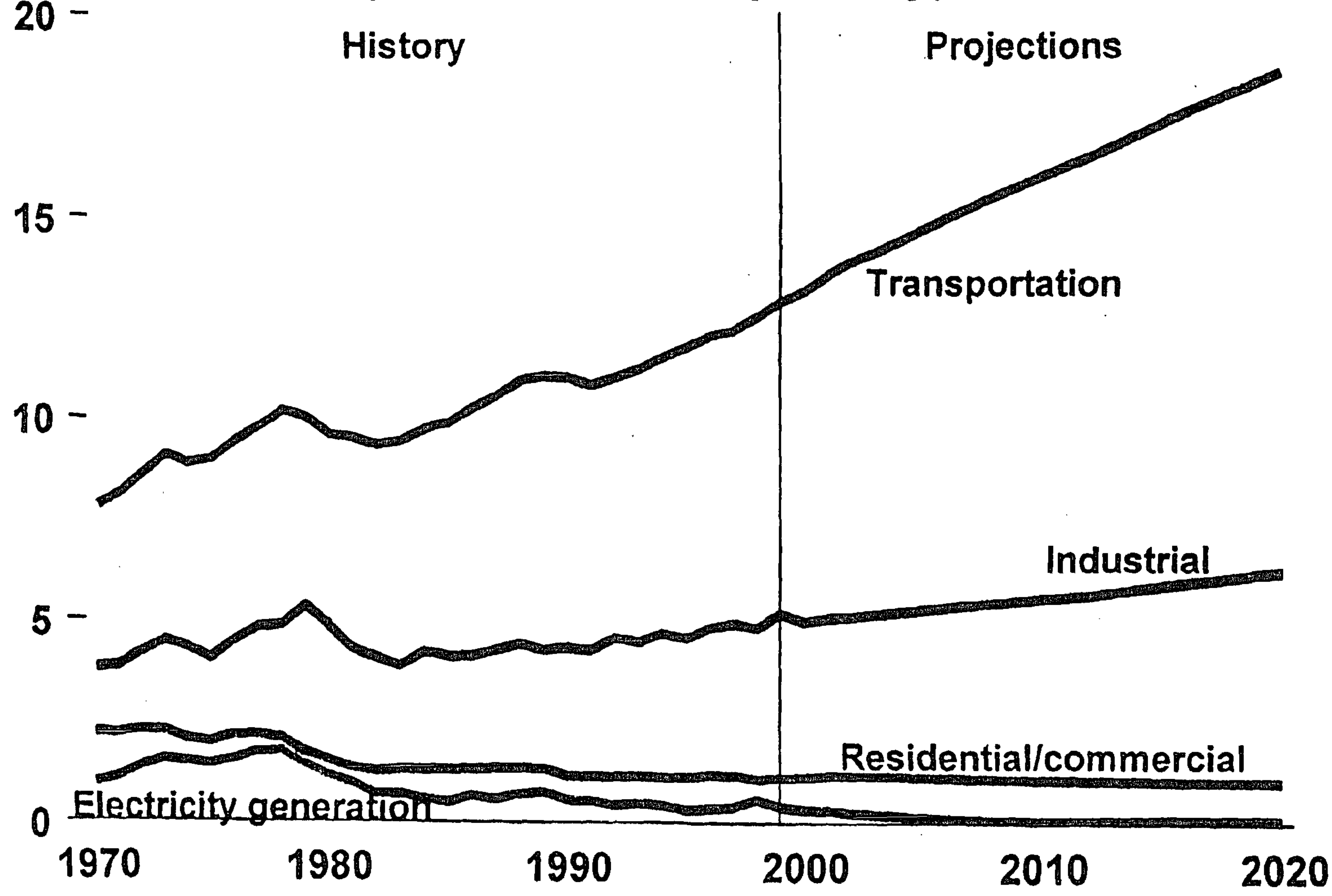
Petroleum Consumption by Sector, 1970-2020
(million barrels per day)



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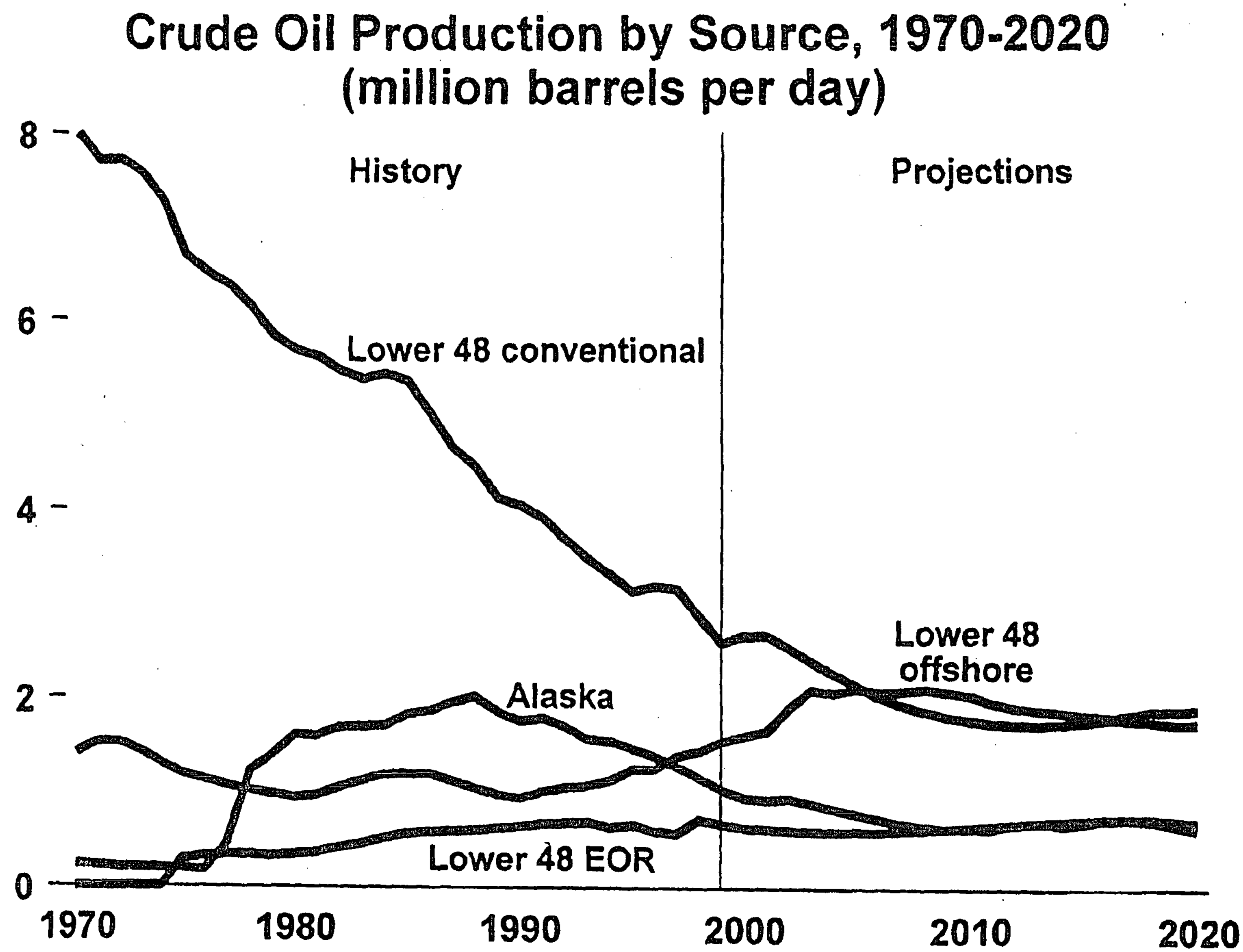

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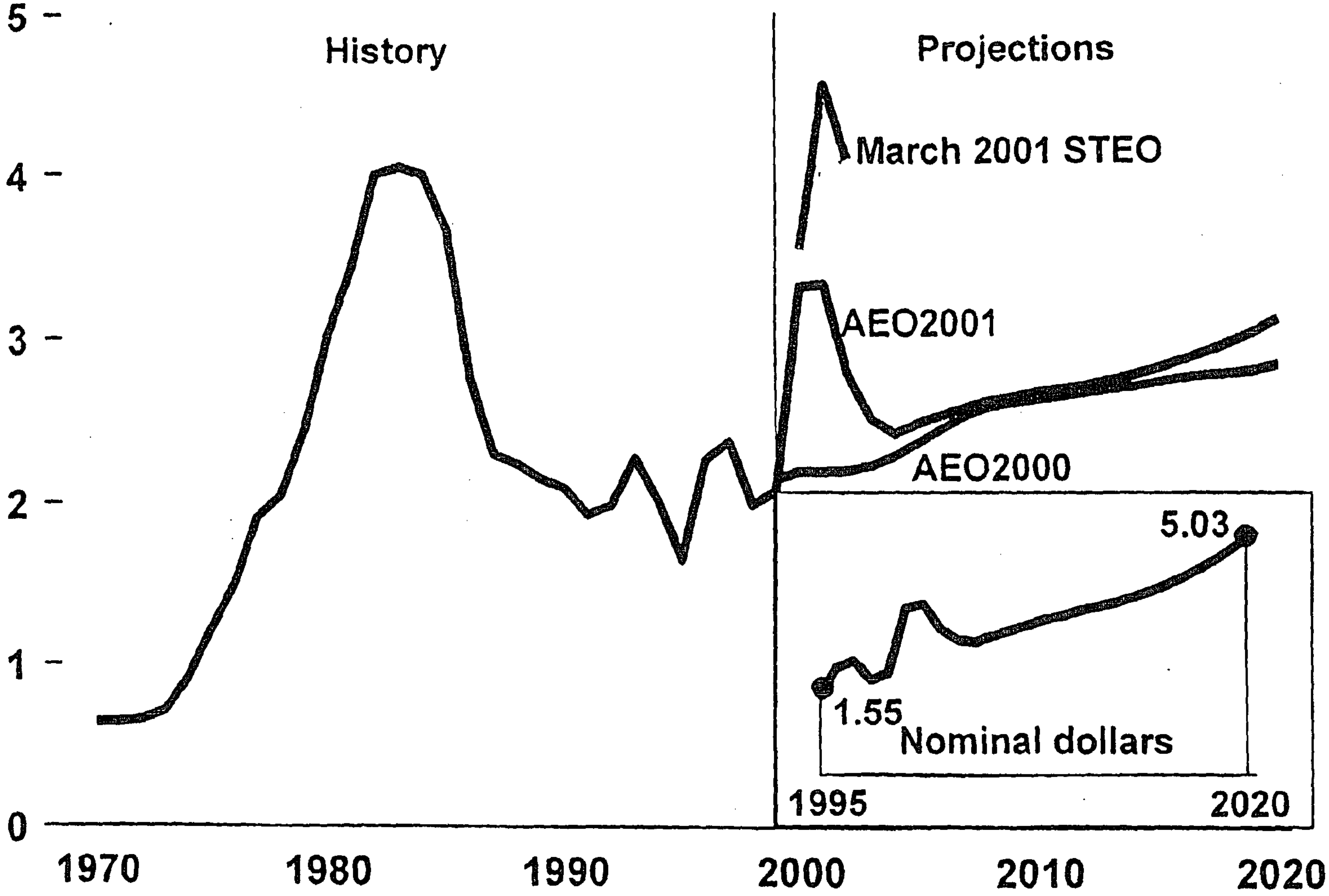
Natural Gas Wellhead Price, 1970-2020
(1999 dollars per thousand cubic feet)



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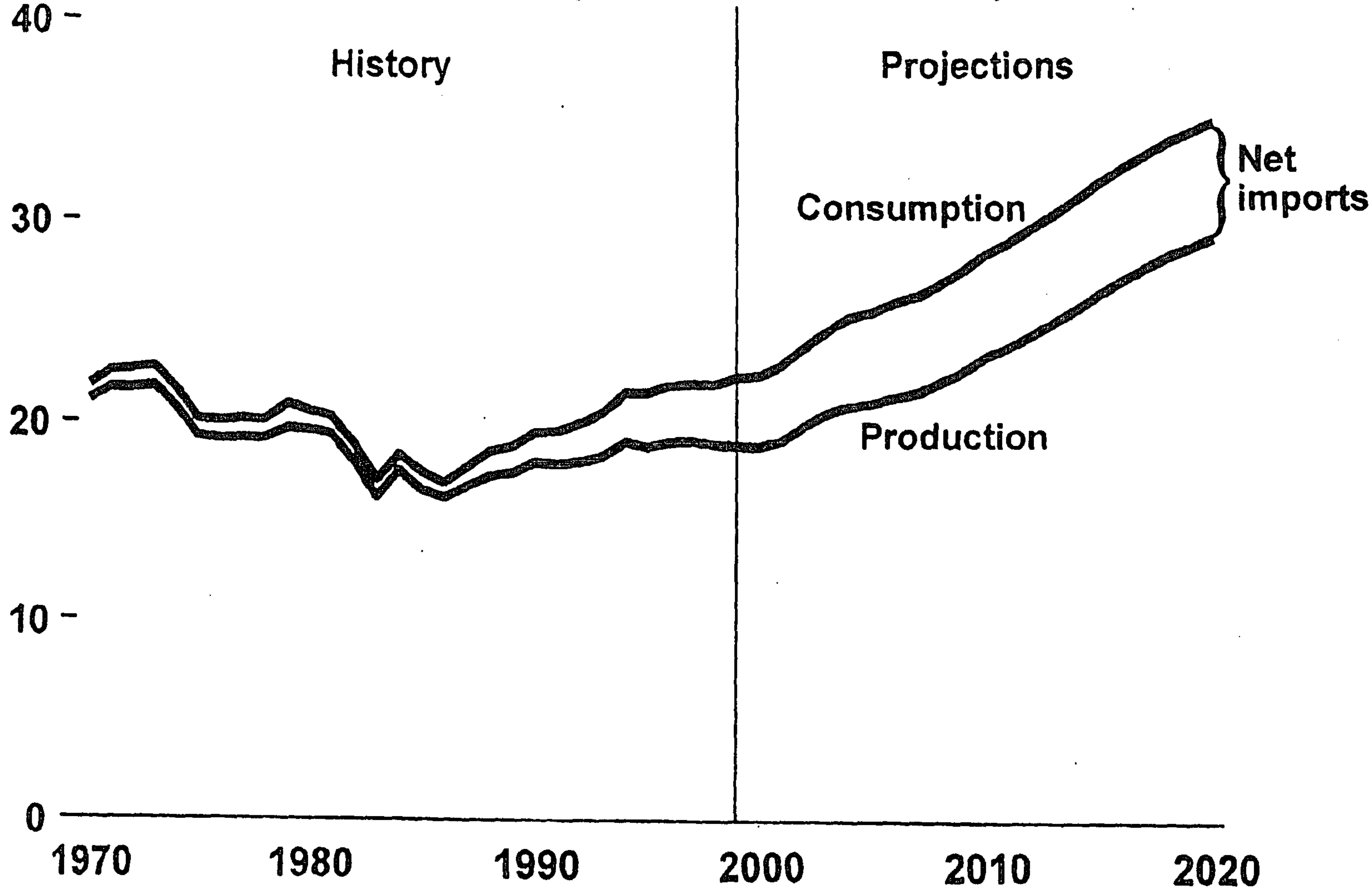
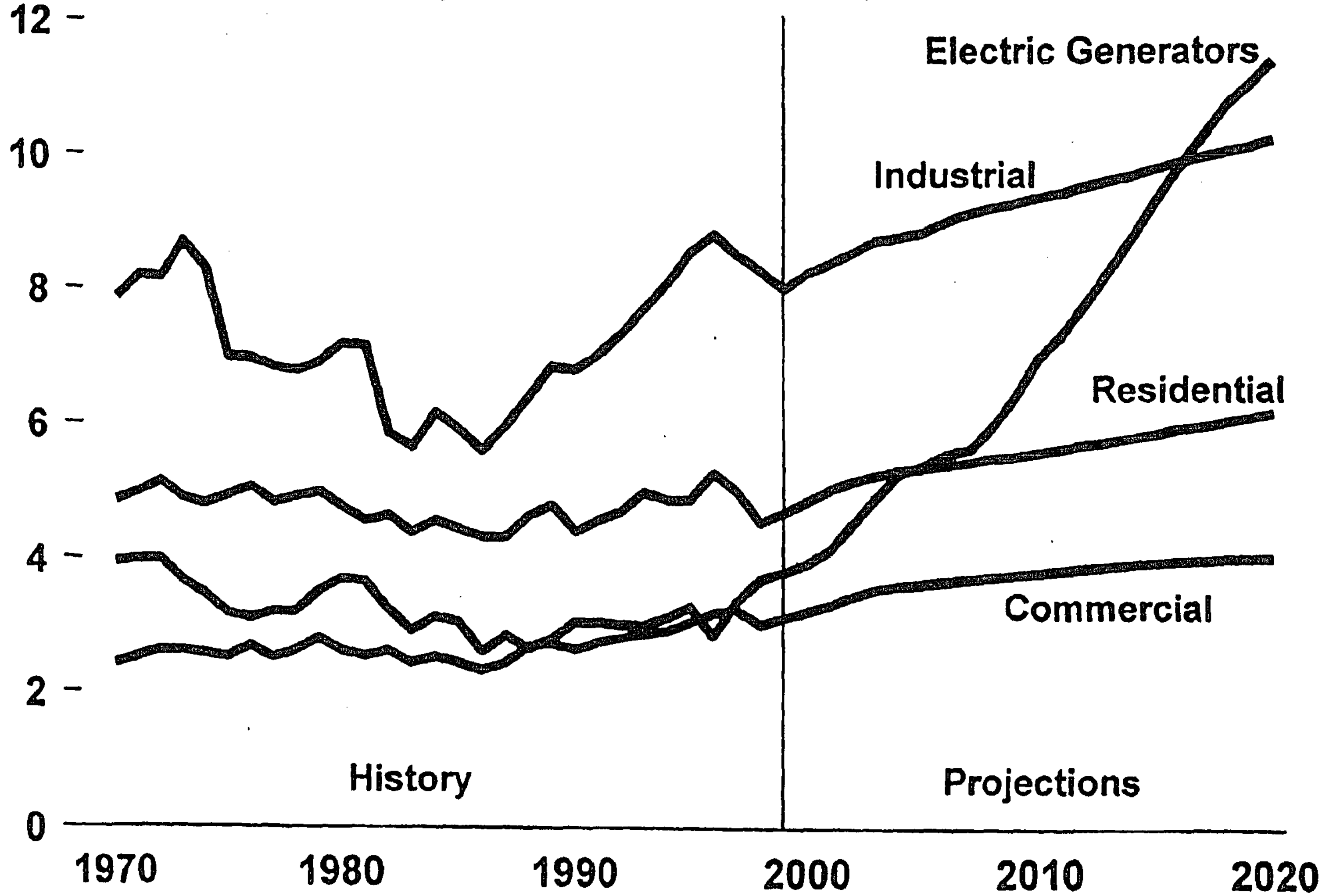
Natural Gas Production, Consumption, and Imports, 1970-2020 (trillion cubic feet)



Natural Gas Consumption by Sector, 1970-2020
(trillion cubic feet)



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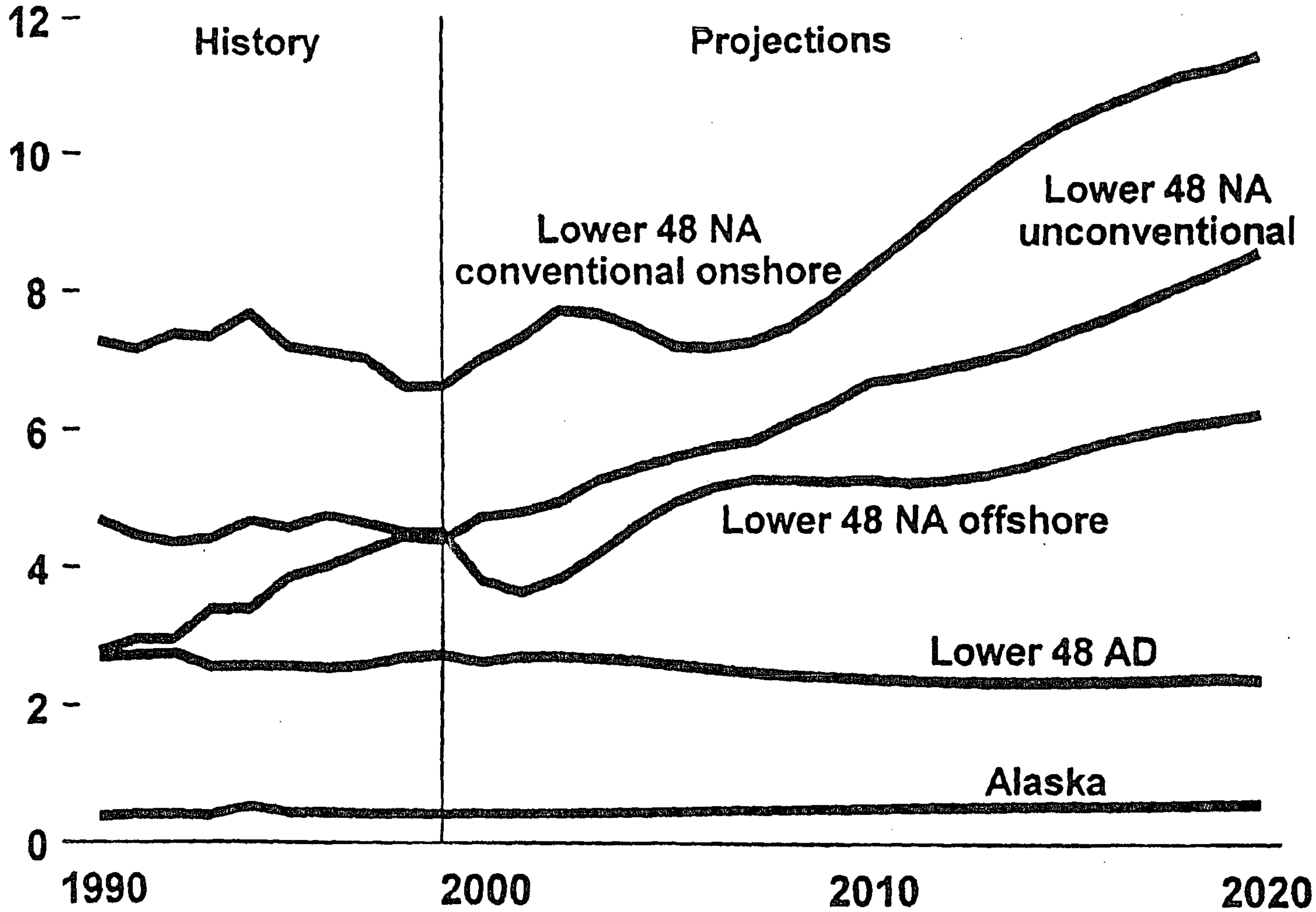
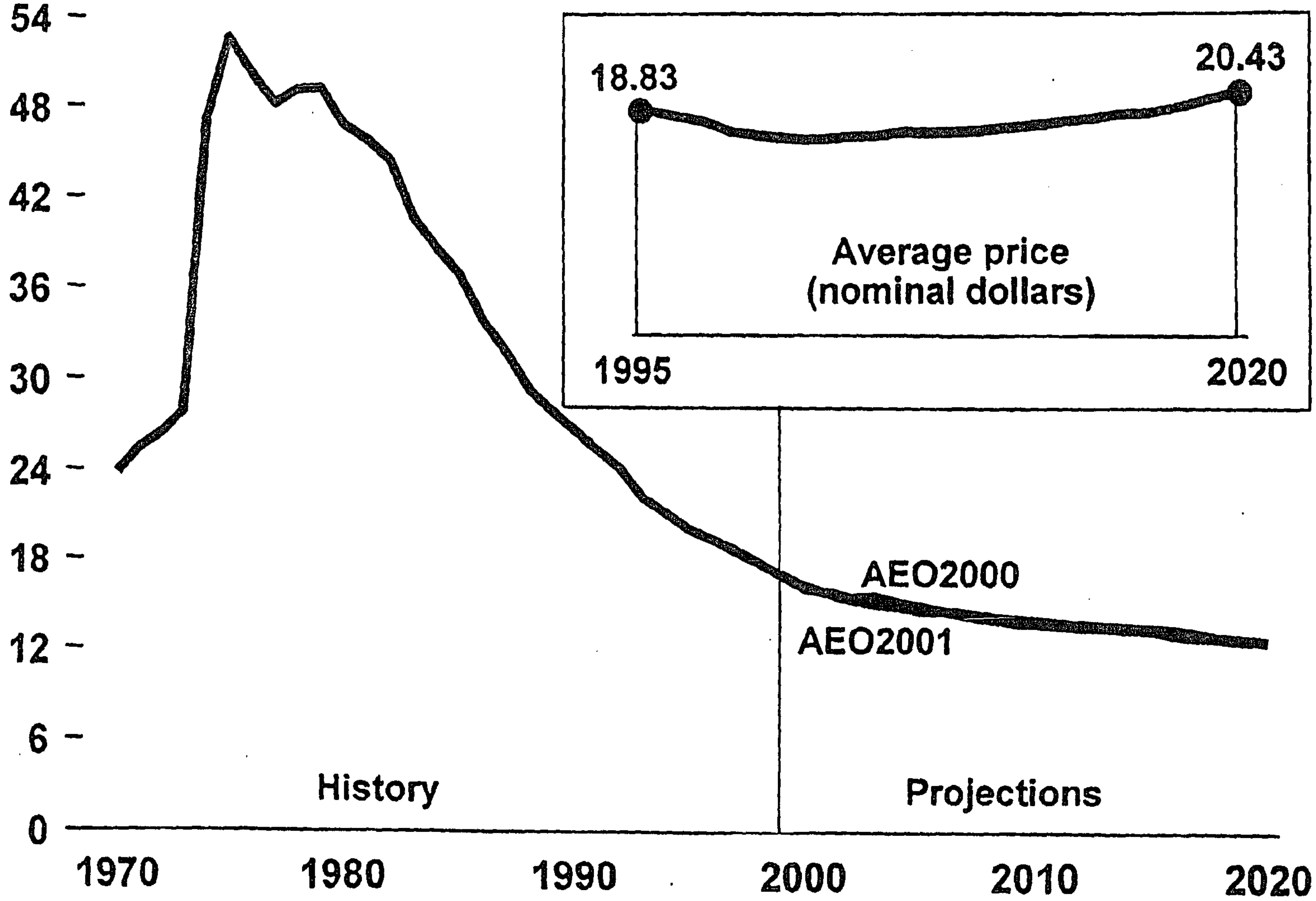
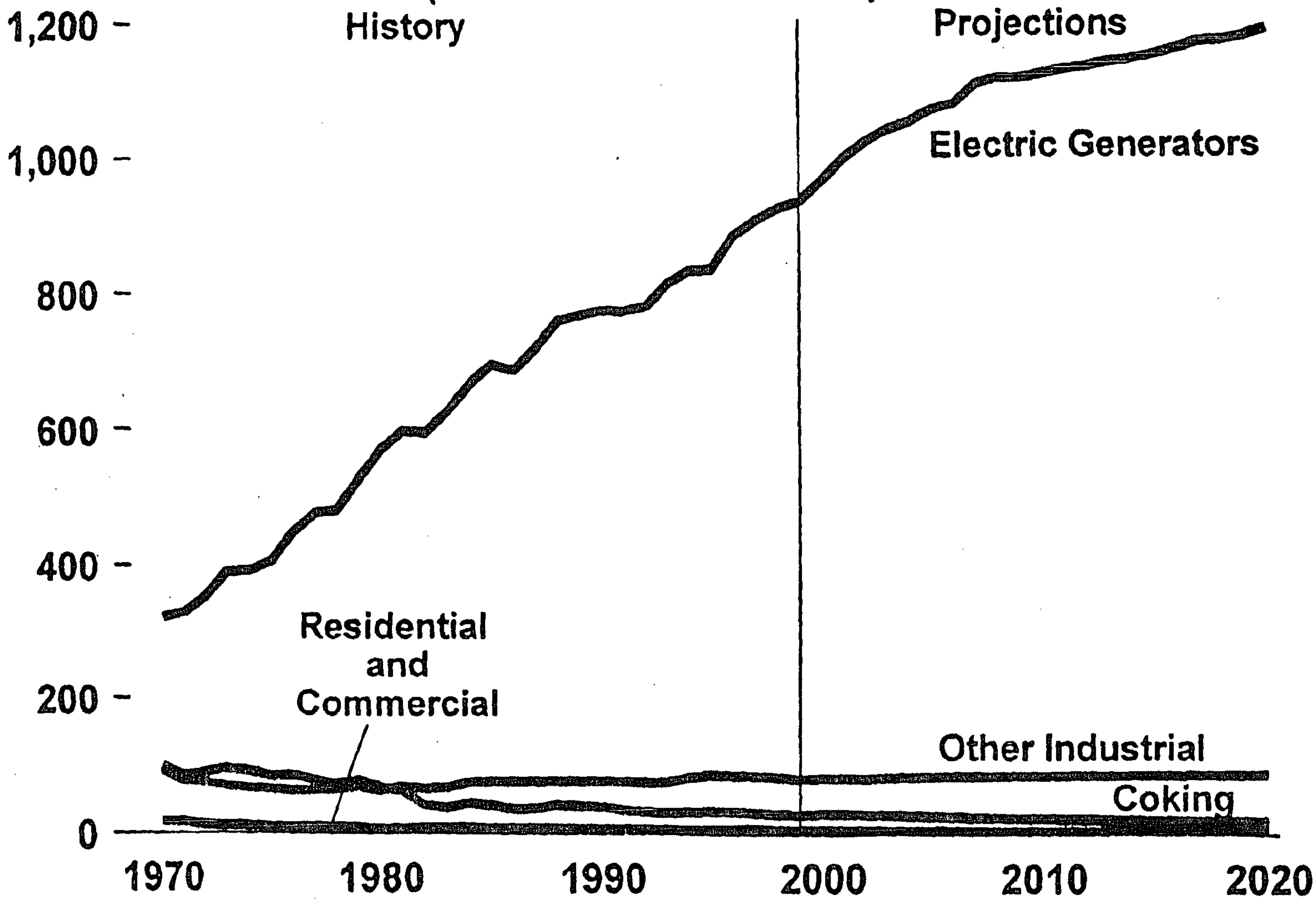
Natural Gas Production by Source, 1990-2020
(trillion cubic feet)



Coal Minemouth Price, 1970-2020
(1999 dollars per ton)



Coal Consumption by Sector, 1970-2020
(million short tons)



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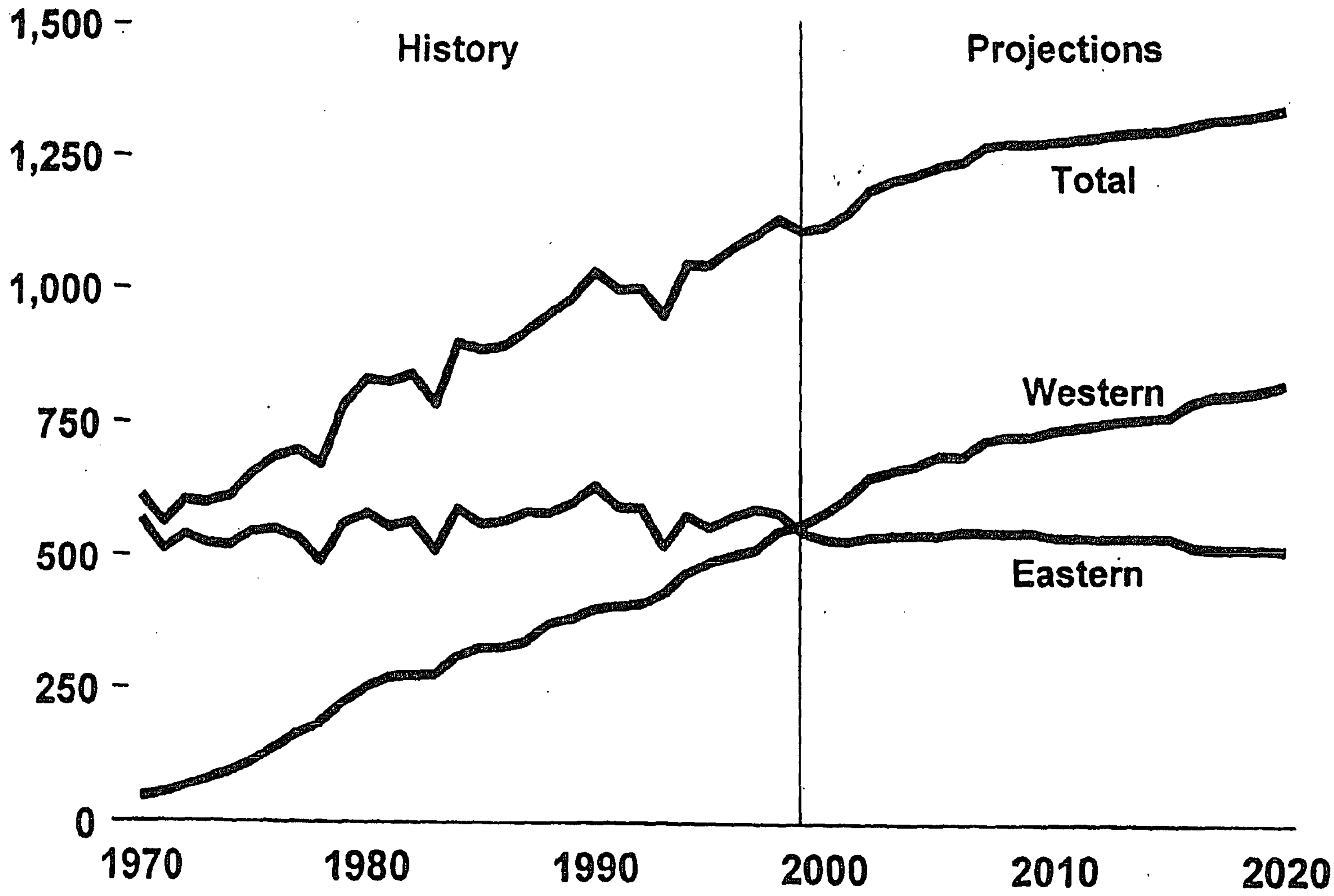
Coal Production by Region, 1970-2020
(million short tons)



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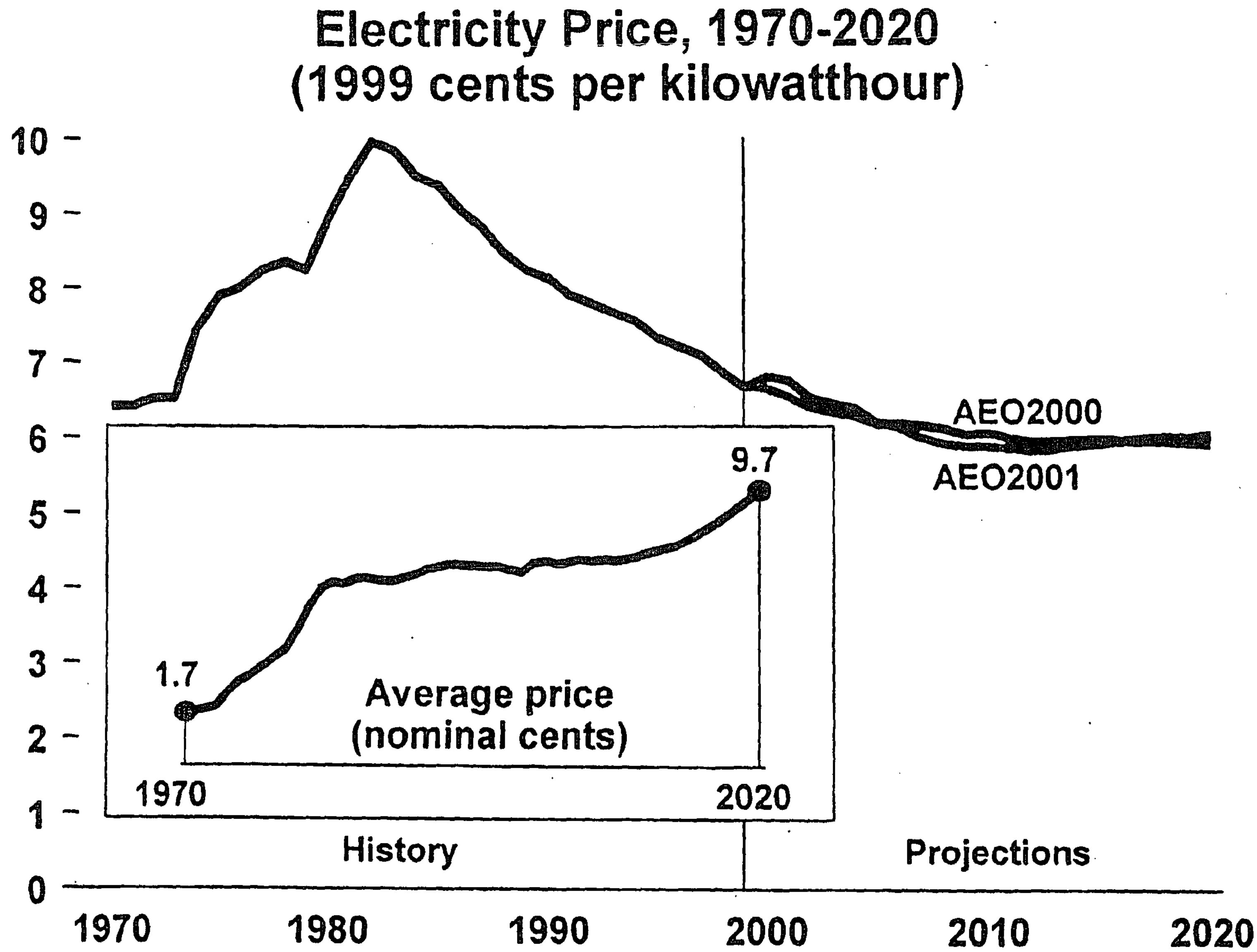

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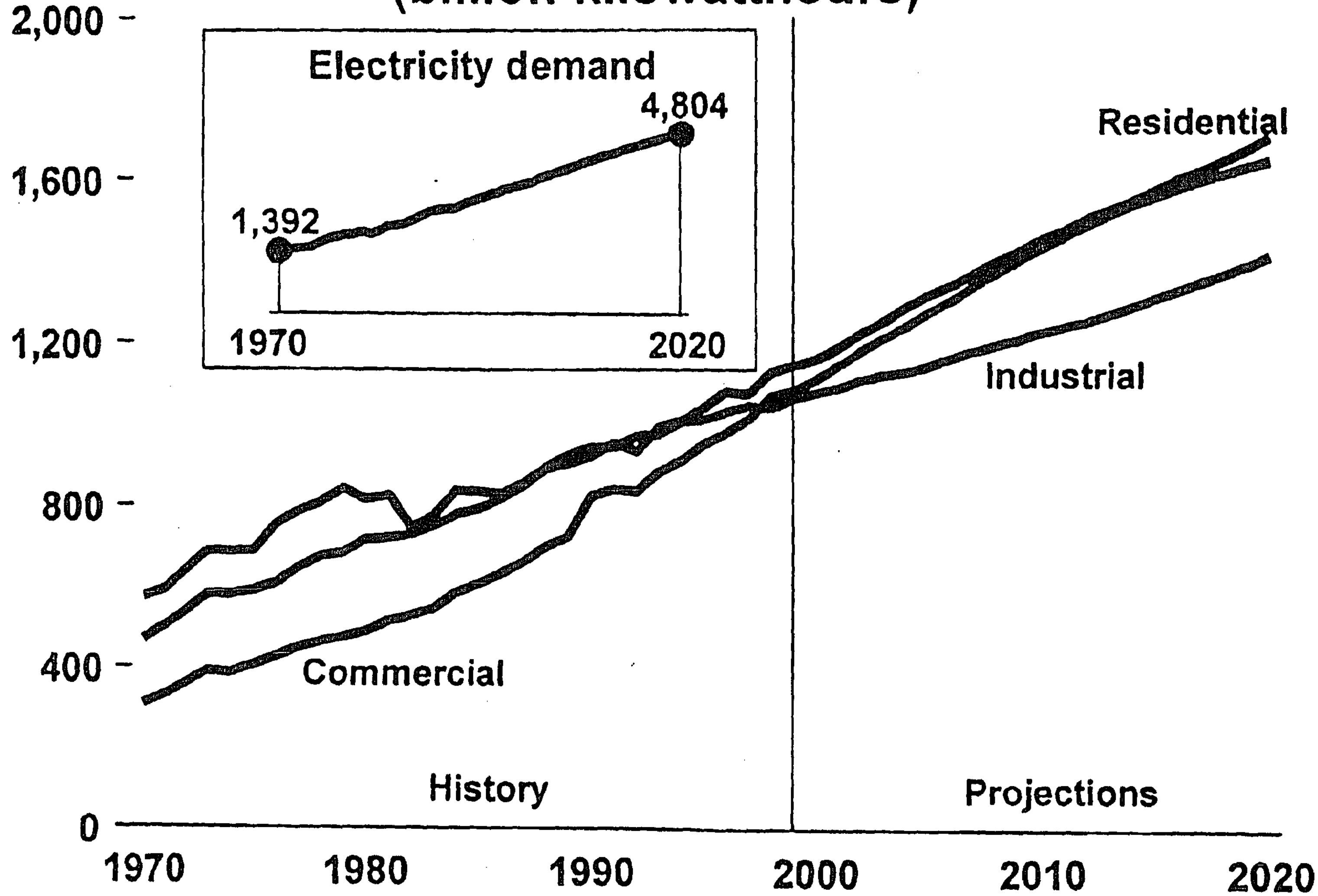
Annual Electricity Sales by Sector, 1970-2020
(billion kilowatthours)



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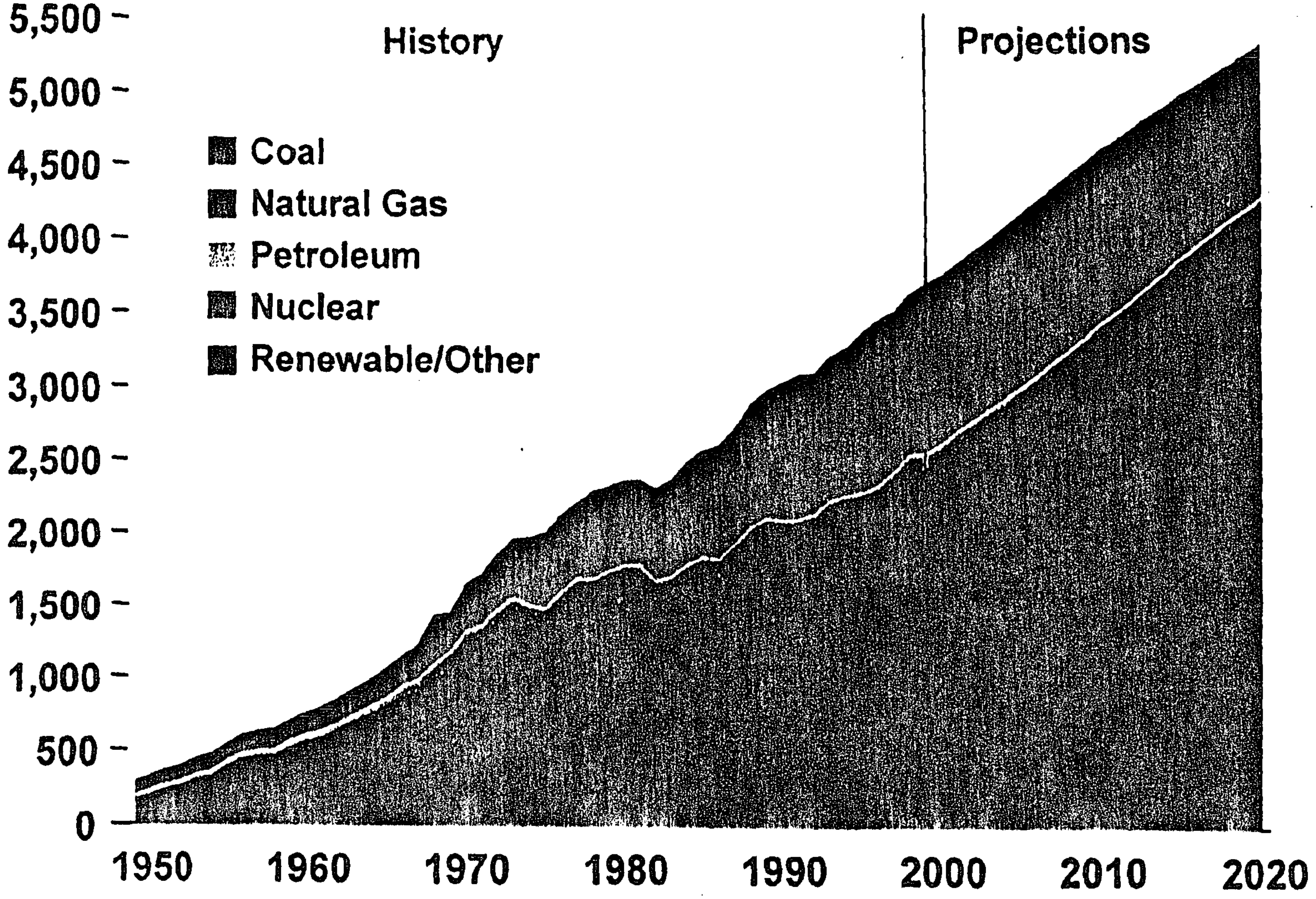
Eiectricity Generation by Fuel, 1949-2020
(billion kilowatthours)



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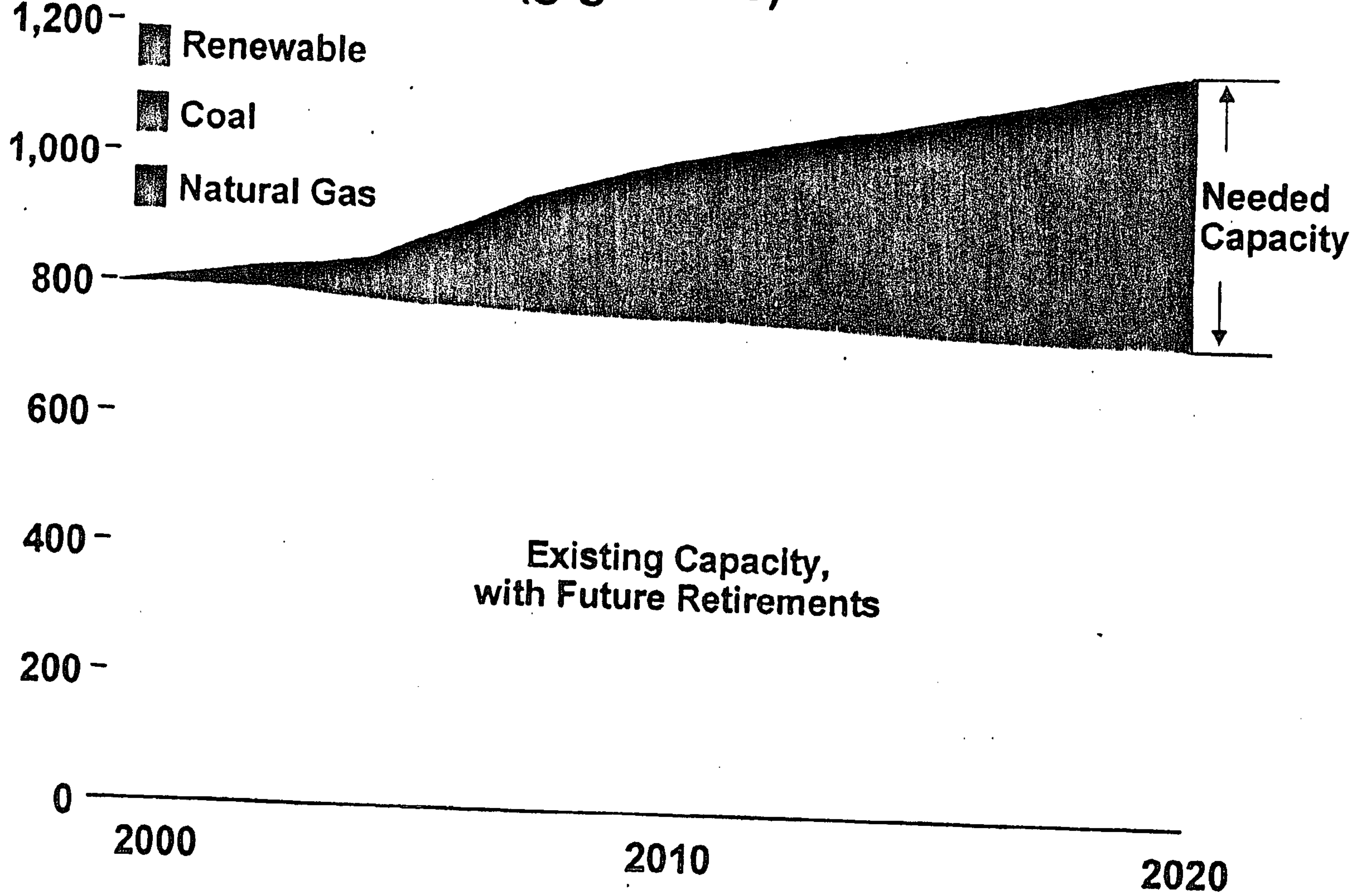
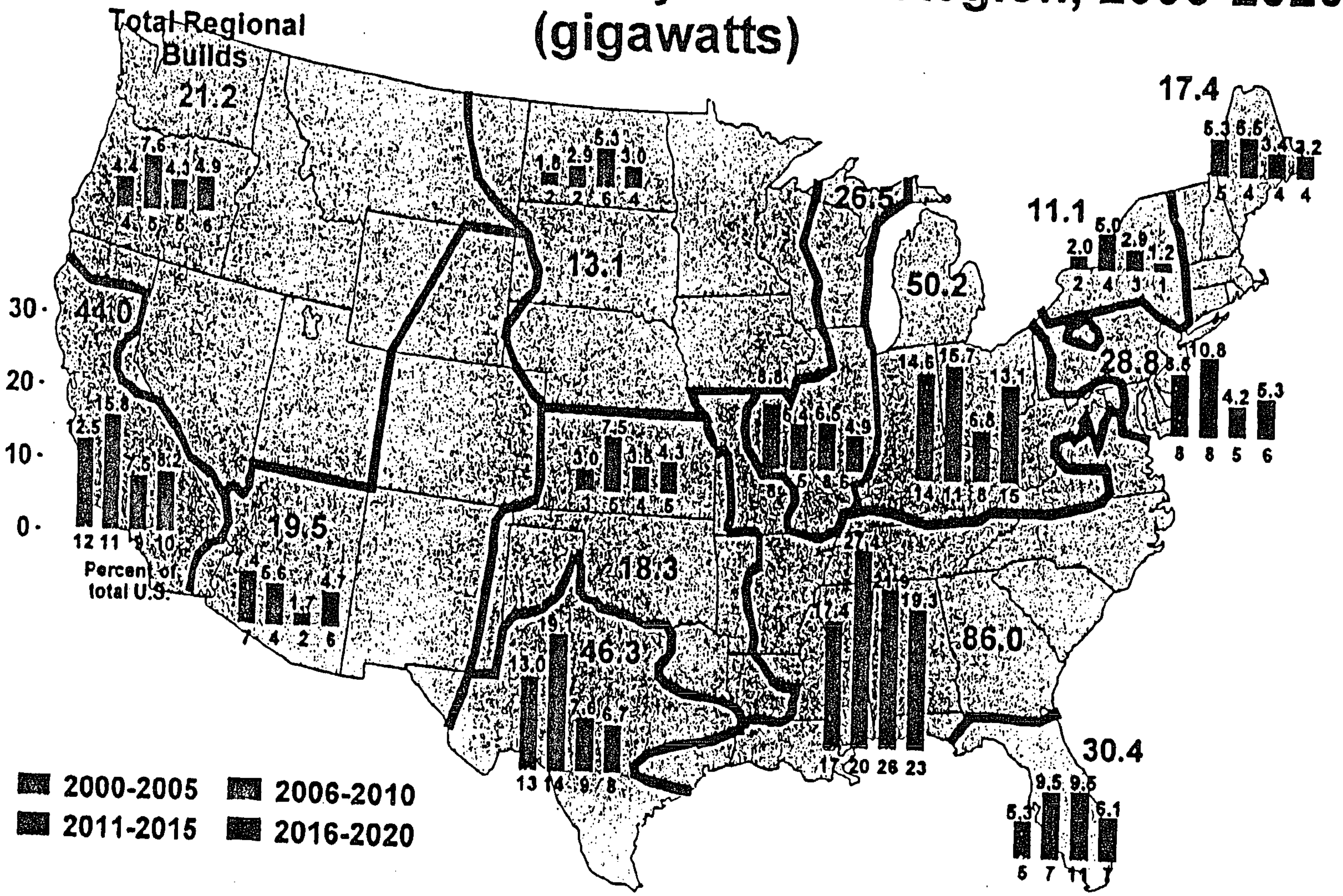
Electricity Capacity, 1999-2020
(gigawatts)



Electricity Generation Capacity Additions by North American Electric Reliability Council Region, 2000-2020 (gigawatts)



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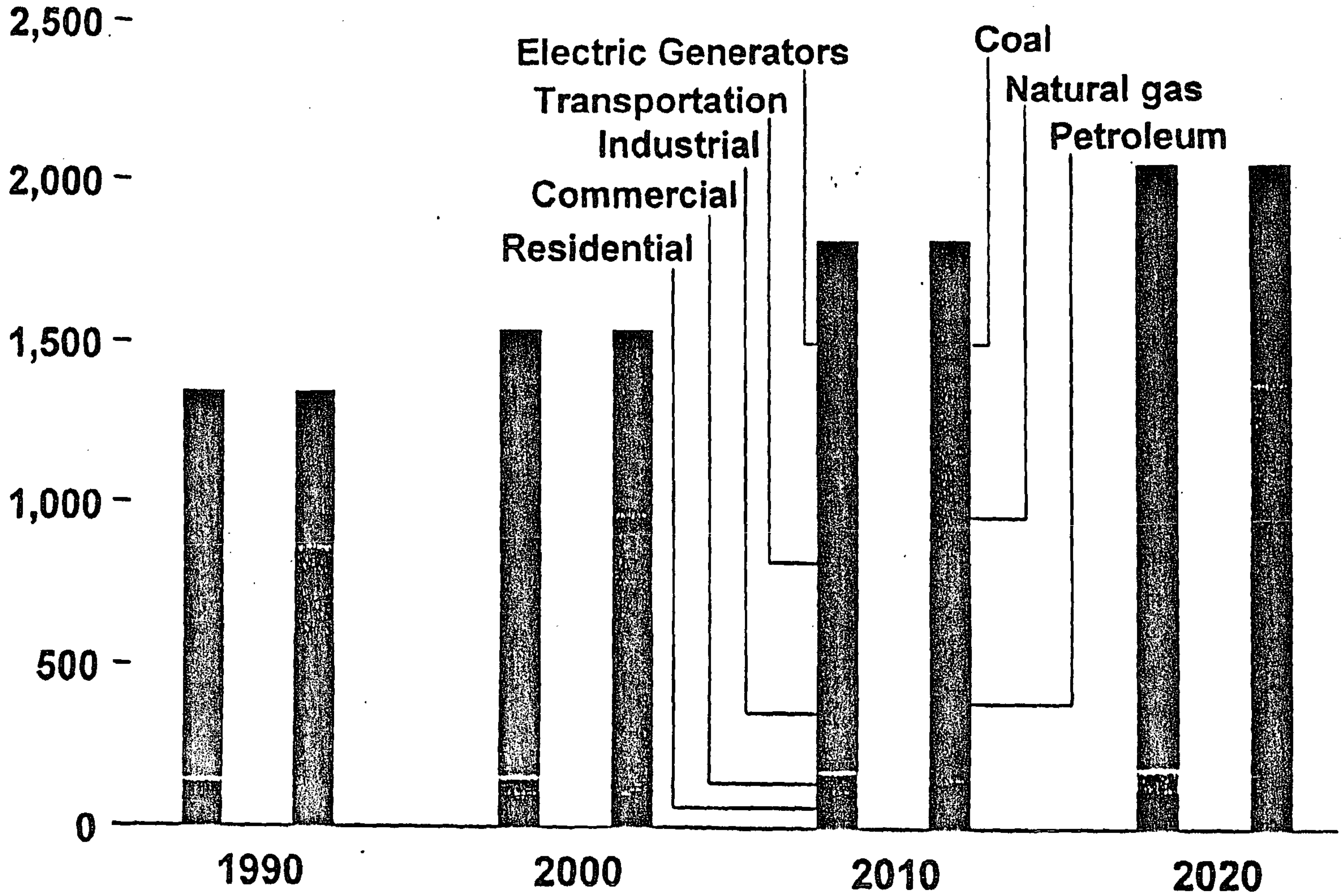
Projected U.S. Carbon Dioxide Emissions by Sector and Fuel, 1990-2020 (million metric tons carbon equivalent)



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STATEMENT OF

JOHN S. COOK

DEPARTMENT OF ENERGY

ENERGY INFORMATION ADMINISTRATION

before the

HOUSE COMMITTEE ON WAYS AND MEANS

SUBCOMMITTEE ON OVERSIGHT

UNITED STATES HOUSE OF REPRESENTATIVES

HEARING ON FEDERAL TAX LAWS

March 5, 2001

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DOE024-0567

Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today to discuss the near-term outlook for energy markets in the United States.

The Energy Information Administration (EIA) is an autonomous statistical and analytical agency within the Department of Energy. We are charged with providing objective, timely, and relevant data, analysis, and projections for the use of the Department of Energy, other Government agencies, the U.S. Congress, and the public. We do not take positions on policy issues, but we do produce data and analysis reports that are meant to help policy makers determine energy policy. Because we have an element of statutory independence with respect to the analyses that we publish, our views are strictly those of EIA. We do not speak for the Department, nor for any particular point of view with respect to energy policy, and our views should not be construed as representing those of the Department or the Administration. However, EIA's baseline projections on energy trends are widely used by Government agencies, the private sector, and academia for their own energy analyses.

EIA produces both short-term and long-term energy projections. The projections through 2002 in this testimony are from the *Short-Term Energy Outlook February 2001* (*STEO*). Each month, EIA updates its *Short-Term Energy Outlook*, which contains quarterly projections through the next 2 calendar years, taking into account the latest developments in energy markets. The *Annual Energy Outlook* provides projections and analysis of domestic energy consumption, supply, and prices through 2020. These projections are not meant to be exact predictions of the future, but represent a likely energy future, given technological and demographic trends, current laws and regulations, and consumer behavior as derived from known data. EIA recognizes that projections of energy markets are highly uncertain and subject to many random events that cannot be foreseen, such as weather, political disruptions, strikes, and technological breakthroughs. In addition, long-term trends in technology development, demographics, economic growth, and energy resources may evolve along a different path than assumed in the *Annual Energy Outlook*. Many of these uncertainties are explored through alternative cases.

The Outlook to 2002

Energy markets in the United States today are characterized by unusually high prices for both petroleum and natural gas, due in large part to a tight balance between supply and demand for both fuels. Reductions in oil production by OPEC and weak production growth from several non-OPEC petroleum-exporting nations have contributed to low oil stocks.

Crude Oil. At its January 17 meeting, OPEC members agreed to reduce production quotas effective February 1, 2001. This decision by OPEC 10 (OPEC, excluding Iraq) is expected to maintain the average U.S. imported crude oil price within and toward the high end of OPEC's target range of $22 to $28 per barrel in 2001 and 2002 (Figure 1). Average imported prices may fall slightly from the estimated value of $27.70 per barrel in 2000 to between $26 and $27 during the 2001 to 2002 period. These prices, as well as all other prices mentioned in this testimony, will be in nominal dollars. EIA expects that oil stocks in the OECD countries will continue to remain lower than normal, preventing prices from falling significantly (Figure 2). Some OPEC members have suggested that further cuts will be needed to maintain world oil supply in balance with demand. Any additional quota reductions will be discussed at the next OPEC ministerial meeting which will be held on March 16, 2001.

Motor Gasoline. The average monthly retail price for regular unleaded motor gasoline fell 11 cents per gallon from September to December. However, with crude oil prices increasing from their December lows combined with lower than normal stock levels, EIA projects that prices at the pump will rise modestly as the 2001 driving season begins in the spring. For the summer of 2001, we expect little difference from the average price of $1.50 per gallon seen during the previous driving season. The annual average retail price of regular motor gasoline is projected to decline from $1.49 per gallon in 2000 to $1.46 per gallon in 2001 to $1.42 per gallon in 2002. Gasoline inventories going into the driving season are projected to be about the same or even less than last year. Relatively low gasoline inventories could set the stage for regional supply problems that once again could bring about significant price volatility in gasoline markets. The prospect of regional supply problems is increased by the differing regional gasoline product requirements, arising from Federal and State air quality programs, which limit the distribution system's flexibility. Regional problems can also arise from temporary or permanent losses of refining capacity. However, it is expected that with a year's experience behind them, the refining industry's ability to make the new type of gasoline initially required last summer should be improved, thus mitigating any problems related to this latest change in gasoline specifications.

Distillate Fuel. The heating season of October through March is now nearing its end, so it is likely that retail heating oil prices have seen their seasonal peak provided no late seasonal surge in heating demand occurs. Warm spells in January and declining crude oil prices in December and January have helped ease heating oil prices. Spot heating oil prices (New York Harbor) fell from $1.05 per gallon on December 6, 2000, to $0.73 per gallon on February 28, 2001. Because of the relatively warm weather in the Northeast during the last half of January and the extremely high level of distillate fuel imports and refinery production so far in 2001, heating oil stock levels have not weakened over the past month or two as would normally occur. Thus, for the country as a whole, distillate stocks are now back within the normal range after being well below normal for most of the winter. However, although retail heating oil prices have come down some recently, they have remained relatively high as demand has continued to be strong. The national average price in December 2000 was about 40 cents per gallon above the December 1999 price. By February 2001, the average price is expected to be about $1.34 per gallon, about 8 cents per gallon less than the record high set in February 2000.

The average bill for a consumer heating with oil in the Northeast States is expected to be nearly $1,000 this winter compared to $760 last winter and less than $600 the previous two winters (Table 1). Of the 7.7 million households in the United States that use oil to heat their homes, 5.3 million households, or roughly 69 percent reside in the Northeast region, which includes New England and the Central Atlantic States. Although consumers this winter have not faced the price spike they saw last winter, consumption is expected to be 11 percent more than last year, because

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of colder weather and high natural gas prices encouraging some customers to switch to distillate fuel oil. Higher consumption levels and higher crude oil prices relative to last winter have combined to push up the expected cost of a gallon of heating oil by 18 percent this winter. Together the increases in consumption and price are expected to raise winter oil heating bills by 31 percent.

Table 1. Winter Heating Oil Costs for an Average Northeast Household Heating with Oil

	1997-1998 Actual	1998-1999 Actual	1999-2000 Actual	2000-2001 Projected
Heating Oil Consumed (gallons)	636	650	644	715
Heating Oil Price (dollars per gallon)	0.92	0.80	1.18	1.39
Heating Oil Cost (dollars)	585	520	760	994

Natural Gas. Spot natural gas prices last summer averaged more than $4 per thousand cubic feet during a normally low-priced season and remained above $5 per thousand cubic feet in the fall, more than double the average price a year earlier (Figure 3). In January 2001, the spot price averaged a record $8.98 per thousand cubic feet. These sustained high prices are largely due to high demand for natural gas in 2000, which exceeded 1999 demand by almost 1 trillion cubic feet, according to preliminary data, and was not matched by an increase in domestic production. U.S. production of natural gas is estimated to have increased by about 0.5 trillion cubic feet in 2000 over 1999 levels. Strong growth in the economy during the first half of the year, cold winter weather late in the year, and increased demand from natural gas-fired power plants throughout the year are the main reasons for high natural gas demand in 2000. Due to high demand for natural gas in the summer of 2000, smaller quantities of natural gas than usual were injected into storage for winter, which is the peak demand period for natural gas (Figure 4).

Demand for natural gas for heating was eased by milder than normal weather during the latter part of January in much of the Nation's gas-consuming regions, which led to a reduction in spot prices to less than $6 per thousand cubic feet. By February 2001, the average spot price for natural gas was about $5.80 per thousand cubic feet. However, spot prices and wellhead prices still remain high by historical standards. EIA projects that winter wellhead natural gas prices will average about $6.10 per thousand cubic feet, more than two and one half times the price of the previous winter season. Assuming normal weather and projected continued low underground storage levels, the annual average wellhead price in 2001 is projected to be about $5 per thousand cubic feet, an increase from the 2000 price of $3.60 per thousand cubic feet. In 2002, we expect the storage situation to improve, leading to a decrease in the average annual wellhead price to $4.50 per thousand cubic feet. Domestic natural gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling experienced over the past year. In 2000, drilling for natural gas in the lower 48 States increased by 45 percent over the 1999 level of 10,500 wells, in response to a 66-percent increase in the average natural gas wellhead price from 1999 to 2000 (Figure 5). Production is estimated to have risen by 1.1 percent in 2000 and is projected to increase further in 2001 and 2002 as higher natural gas prices are expected to encourage a moderate growth in supply. In contrast, natural gas production declined slightly from 1997 to 1998 and from 1998 to 1999.

Of the 101.5 million U.S. households, 53 percent use natural gas for home heating. The highest concentration of households heating with natural gas–83 percent–is located in the Midwest. The average natural gas home heating bill in the Midwest is expected to approach $1,000 this winter (Table 2). Compared to last winter, colder weather is expected to increase residential gas consumption by 18 percent in the Midwest. Residential gas prices are projected to be 50 percent higher than last winter because growing demand and lagging growth in supply resulted in reduced natural gas storage levels at the beginning of the heating season. Together, increased consumption and prices are expected to yield winter heating bills that are 77 percent above last winter. The sharp increase in natural gas and heating oil prices has a particularly severe impact on low-income consumers that use natural gas for heating. In recent months, 5 million consumers have applied for Federal and State governmental assistance to pay their heating bills, an increase of 1 million from last year. The Federal energy program directed at providing financial assistance to low-income households, the Low Income Home Energy Assistance Program (LIHEAP), is discussed in the Addendum.

Table 2. Winter Natural Gas Costs for an Average Midwest Household Heating with Natural Gas

	1997-1998 Actual	1998-1999 Actual	1999-2000 Actual	2000-2001 Projected
Natural Gas Consumed (thousand cubic feet)	82.4	84.5	81.7	96.7
Natural Gas Price (dollars per thousand cubic feet)	6.56	6.27	6.61	9.89
Natural Gas Cost (dollars)	541	530	540	956

Electricity. Demand for electricity increased an estimated 3.6 percent from 1999 to 2000. Growth of 2.4 and 2.3 percent is projected in 2001 and in 2002, respectively, slowing in part because of reduced projected economic growth. Electricity demand for this winter is expected to be 4.5 percent higher than the previous winter, due to higher residential and commercial demand and the cold temperatures in November and December. Natural gas deliverability problems in California have helped to increase natural gas prices and have frequently caused interruptible customers, including electricity generators, to have service curtailed in that State. In California, and in the West as a whole, capacity additions have not kept pace with demand growth over the past ten years, contributing to the current low electricity generation reserve margins. The current situation in California is characterized by low natural gas storage, natural gas pipeline bottlenecks, unexpected plant outages, low availability of hydropower resources, and electricity demand in excess of available supply. In addition, the San Onofre 3 nuclear unit is currently offline due to a fire in early February and may not return to service for several months. Typically California would export electricity in the winter season but has required net electricity imports from neighboring states this year. The average residential price of electricity in the United States is projected to increase from 8.2 cents per kilowatthour in 2000 to 8.3 and 8.4 cents per kilowatthour in 2001 and 2002, respectively.

Conclusion

In the near term, we expect crude oil and petroleum prices to remain about the same as their current levels throughout this year with natural gas prices declining further next year as production increases. Stock levels of both petroleum and natural gas are likely to remain low, and natural gas prices are projected to remain higher than normal largely due to high demand in 2000. Home heating oil and natural gas bills are expected to approach $1,000 this winter, substantially higher than last winter.

Thank you, Mr. Chairman and members of the Subcommittee. I will be happy to answer any questions you may have.

Figure 1. Crude Oil Prices, 1998-2002
(dollars per barrel)

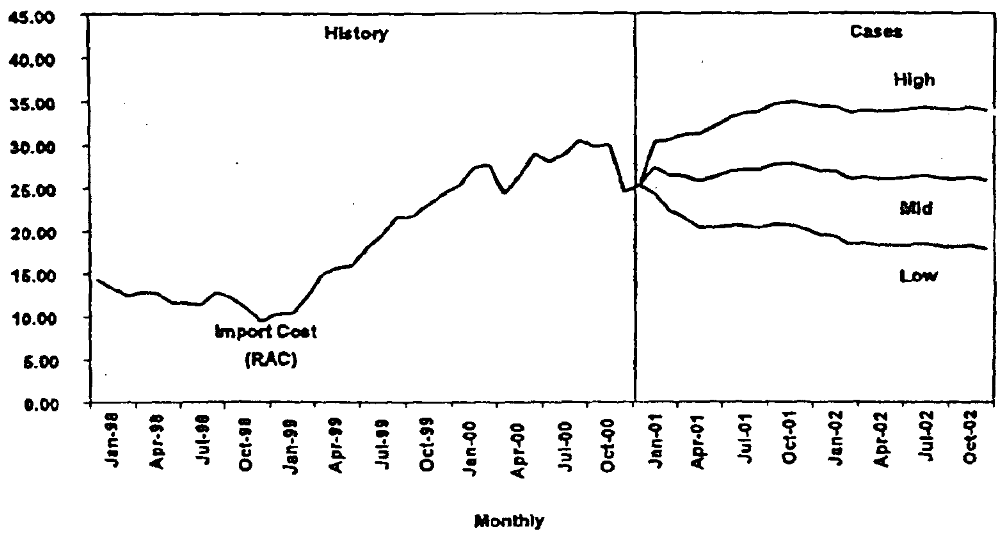

Figure 2. Total OECD Oil Stocks, Including Commercial and Government Stocks, 1995-2002
(million barrels)

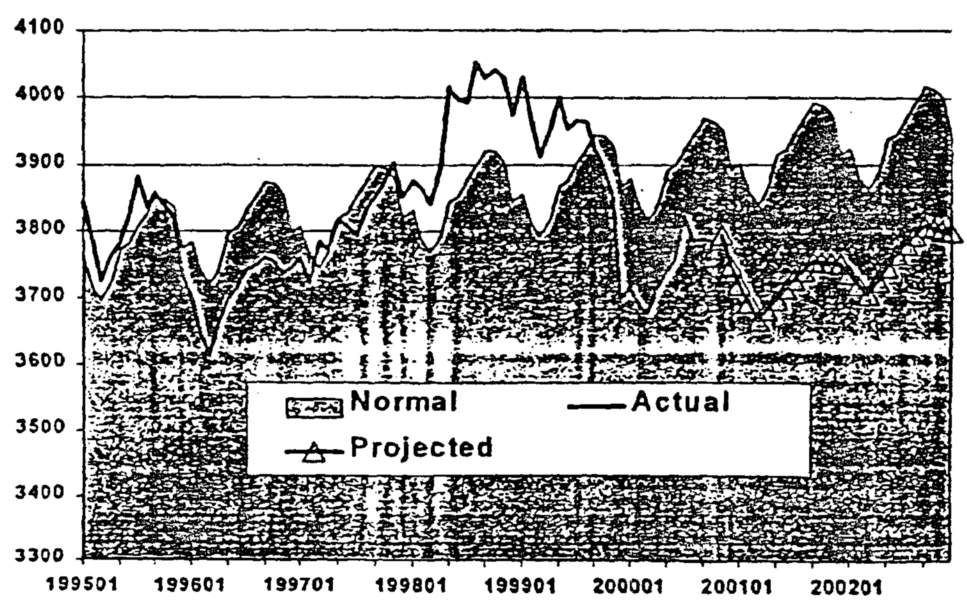

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Figure 3. Wellhead Natural Gas Prices, 1999-2002
(dollars per thousand cubic feet)

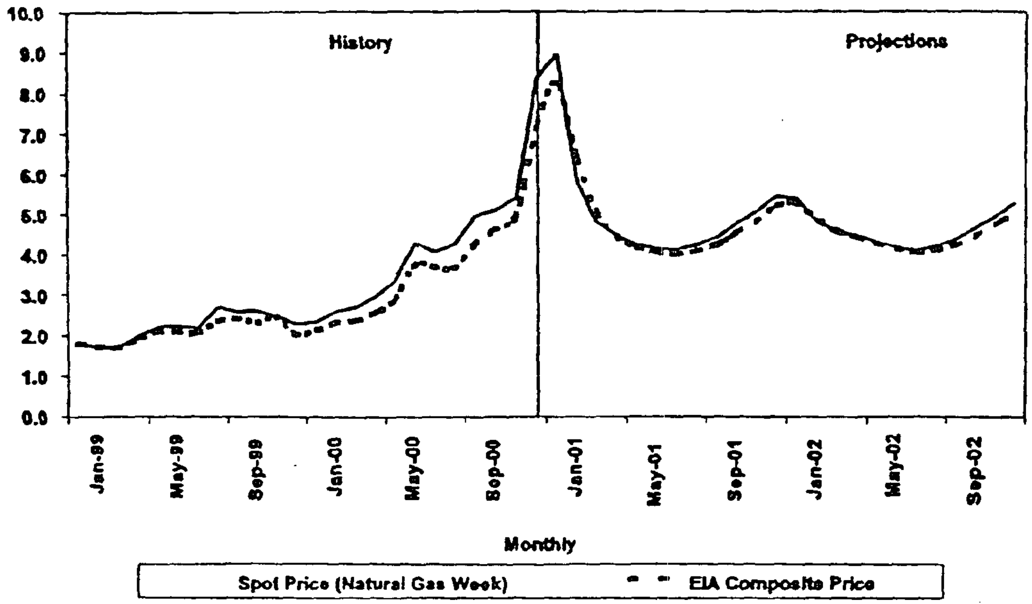

Figure 4. Working Gas in Storage, 1998-2002
(billion cubic feet)

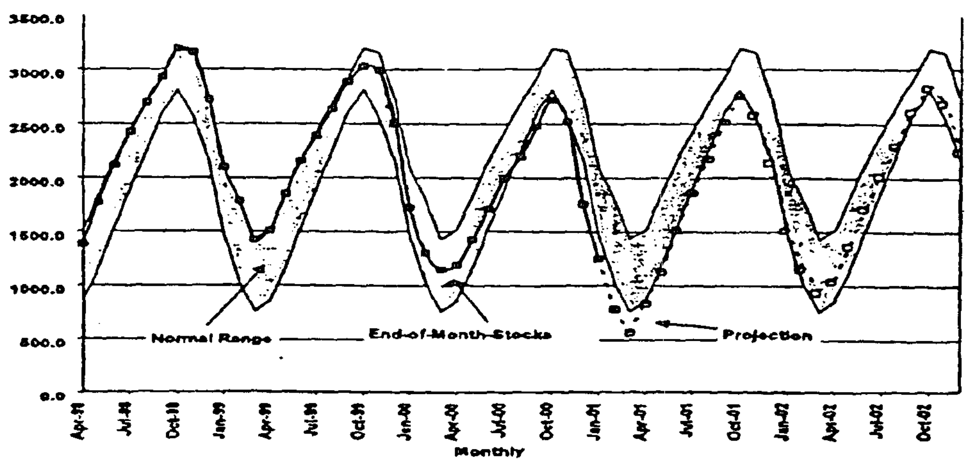

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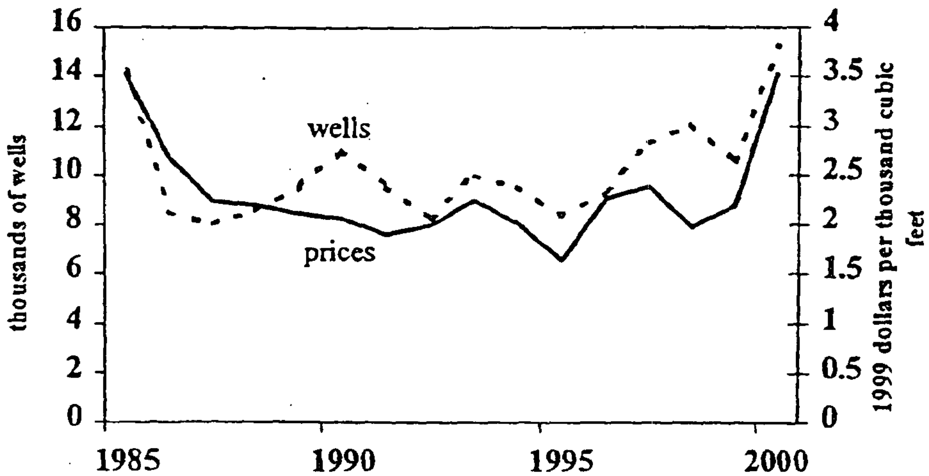
Figure 5. Lower 48 Natural Gas Wells Drilled and Average Wellhead Prices, 1985-2000



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Addendum

EIA performs special studies at the request of the Department of Energy, the U.S. Congress, and other government agencies. In 1999 and 2000, EIA performed an analysis of Federal energy financial incentives at the request of the Department of Energy's Office of Policy. The results of this analysis were published in *Federal Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy* and *Federal Financial Interventions and Subsidies in Energy Markets 1999: Energy Transformation and End Use*.[1] In 2000, EIA performed a study of proposed tax credits in the Climate Change Technology Initiative at the request of the House Committee on Government Reform, published in *Analysis of the Climate Change Technology Initiative: Fiscal Year 2001*.[2] These reports are the basis of the analysis in this Addendum.

Federal Energy Expenditures and Tax Expenditures[3]

This section discusses Federal tax expenditures and direct expenditures in fiscal year 1999 based on the cost of the programs to the Federal budget.[4]

Direct Expenditures

Currently, four energy programs provide payments to producers or consumers. Three of them focus on energy end use, the Low Income Home Energy Assistance Program (LIHEAP), the Weatherization Assistance Program, and the State Energy Program, and the fourth program, the Renewable Energy Production Incentive (REPI), focuses on primary energy.

Low Income Home Energy Assistance Program. LIHEAP, originally established in 1981, is a block grant program of the Department of Health and Human Services under which the Federal Government gives States, the District of Columbia, U.S. territories, and Indian tribal organizations annual grants to provide home energy assistance for needy households. For fiscal year 1999, LIHEAP was the largest program among direct energy expenditures, with an expenditure of $1.255 billion (Table 3), including $155 million in emergency funds for cooling assistance. LIHEAP disburses block grants to the States, which in turn provide assistance to low-

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[1]Energy Information Administration (EIA), *Federal Financial Interventions and Subsidies in Energy Markets 1999: Primary Energy*, SR/OIAF/99-03 (Washington, DC, September 1999), www.eia.doe.gov/oiaf/servicerpt/subsidy/index.html, and EIA, *Federal Financial Interventions and Subsidies in Energy Markets 1999: Energy Transformation and End Use*, SR/OIAF/2000-02 (Washington, DC, May 2000), www.eia.doe.gov/oiaf/servicerpt/subsidy1/index.html.

[2]Energy Information Administration, *Analysis of the Climate Change Technology Initiative: Fiscal Year 2001*, SR/OIAF/2000-01 (Washington, DC, April 2000), www.eia.doe.gov/oiaf/climate/index.html.

[3]Tax expenditures below $5 million are not included in this analysis. An example is the Outer Continental Deep Water Royalty Relief Act, signed on November 28, 1995, which provides incentives for oil and gas production in the deep waters of the Gulf of Mexico by eliminating certain royalties on deepwater leases. The value of royalty reductions was $1.5 million in 1998 and $1.1 million in 1999 through April.

[4]1999 data are the latest available.

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income households for payment of utility bills and for weatherization of residences. The precise eligibility criteria vary from State to State. In general, recipients must have income that is less than 150 percent of the poverty level for their State or less than 60 percent of the State's median income. No household with income below 110 percent of the poverty guidelines may be excluded.

Weatherization Assistance Program and State Energy Program. Also included as a direct expenditure is DOE's program of grants for conservation and technical assistance, with fiscal year 1999 funding of $166 million (nominal dollars). The Weatherization Assistance Program supported the weatherization of 67,330 low-income homes, with an appropriation of $133 million for fiscal year 1999—approximately $1,700 to $2,000 per household minus overhead and administration costs. The State Energy Program, which supports grants to promote innovative State energy efficiency and renewable energy activities, was funded at $33 million for fiscal year 1999. In contrast to LIHEAP, the DOE programs subsidize energy conservation and are designed to reduce energy consumption.

Renewable Energy Production Incentive. The Renewable Energy Production Incentive (REPI) program is part of an integrated strategy in the Energy Policy Act of 1992 to promote increases in the generation and utilization of electricity from renewable sources and to advance renewable energy technologies. The program provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Qualified generation sources receive a payment of about $0.015 per kilowatthour, except that the amount of money is capped by a budgetary allocation. If the available funds are insufficient to cover the full production incentive payments, partial payments are made on a *pro rata* basis. The size of the REPI was relatively small at $4 million in 1999.

Table 3. Funding for Direct Energy Expenditures, Fiscal Year 1999
(million 1999 dollars)

Program	Expenditure
Low Income Home Energy Assistance Program	1,255
Building Technology Assistance Program	
Weatherization Assistance Program	133
State Energy Program	33
Renewable Energy Production Incentive Credit	4
Total	1,425

Tax Expenditures

Tax expenditures are provisions in the tax code that reduce the tax liability of firms or individuals who take specified actions that affect energy production, consumption, or conservation in ways deemed to be in the public interest. There is a variety of tax expenditures which are described below. The most important of these in absolute dollar terms affect the oil and gas production industry and producers of alcohol-based fuels. Tax expenditures are separated

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into those affecting primary energy from those affecting energy transformation and end use in order to identify the affected fuels when possible.

Tax Expenditures Applied to Primary Energy

Most of the primary energy tax expenditures and preferential energy excise taxes are accounted for by only a few provisions, but those provisions are important in terms of their effects. They apply principally to oil and gas and, to a lesser extent, to alcohol for motor fuels and to coal. Alternative forms of energy benefit to only a small degree. Solar, wind, biomass, and geothermal energy facilities are beneficiaries of the New Technology Credit. Primary energy tax expenditures equaled roughly $2 billion in 1999 (Table 4).

Preferential Tax Rates. Only one type of energy tax expenditure involving preferential tax rate treatment is currently operative. It applies to royalty income derived from certain coal operations. The royalty income of individual owners of coal leases is taxed at the lower individual capital gains tax rate of 28 percent rather than at the higher regular individual top tax rate of 39.6 percent, if the owners so choose. The small preferential rate tax expenditure (revenue loss) for coal of $65 million benefits only individual owners at present (Table 4).

Tax Deferrals. Tax deferrals generate tax expenditures that have a unique feature, in that they can be negative. Tax deferrals can be viewed as interest-free loans by the Government to taxpayers. These temporary revenue losses are recorded as positively valued tax expenditures. When the loans are repaid they are treated as negative tax expenditures. In any given year the measured net value of newly made loans and loans repaid can therefore be either positive or negative. Tax deferrals can never be negative, however, because interest-free loans always benefit the recipient. The value in any given year can be viewed as the amount that can be earned by investing the loans that are outstanding in that year. Two tax deferral types of energy tax expenditures exist:

- *Exploration and Development Expenditures*. Tax law allows energy producers, principally oil and gas producers, to expense certain exploration and development (E&D) expenditures rather than capitalizing them and cost-depleting them over time. The most important of these expenditures consist of intangible drilling costs (IDCs) associated with oil and gas investments. IDCs are costs incurred in developing and drilling oil, gas, and geothermal wells up to the point of production. Major (or integrated) oil companies can expense 70 percent of their IDCs for successful domestic wells and 100 percent for unsuccessful domestic wells. The remaining 30 percent must be amortized over 5 years. Independent (or nonintegrated) oil producers can expense 100 percent of their IDCs for all domestic wells. Producers of other fuel minerals can also expense certain E&D expenditures. For example, coal producers can expense 70 percent of their surface stripping and other selected expenditures. The remainder must be amortized over 5 years.

  The value of the E&D tax expenditure provision applied to oil, gas, and coal was an estimated negative $70 million in fiscal year 1999. The negative value represents a gain

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in Government revenue rather than a loss. The gain represents, in effect, a repayment of the principal on a Government loan (or prior tax deferral).

– *Exemption from Passive Loss Limitations for Working Interests in Oil and Gas Properties*. This exemption allows owners of working interests to offset their losses from passive activities against active income. Under normal rules, passive losses remaining after being netted against passive incomes can only be carried over to future period passive incomes. The passive loss limitation provision and the oil and gas exception to it apply principally to partnerships and individuals rather than corporations. The value of this tax expenditure in fiscal year 1999 was an estimated $35 million.

Tax Credits. The four energy tax credit expenditure provisions are the Enhanced Oil Recovery Credit, Alternative Fuel Production Credit, Alcohol Fuel Credit, and New Technology Credit. These credits all apply to unconventional forms of energy or means of producing energy.

– *Enhanced Oil Recovery Credit*. Section 43 of the Internal Revenue Code provides taxpayers an enhanced oil recovery (EOR) credit equal to 15 percent of their qualified EOR costs. Section 43 was a part of the Omnibus Budget Reconciliation Act of 1990, which made several changes to capital cost recovery methods. The Section 43 credit is phased out if oil prices rise above a certain level, i.e., $28 per barrel (in 1991 dollars).

  The value of this tax expenditure is estimated at $160 million for fiscal year 1999. The credit prolongs the lives of some wells, thus increasing the total volume of hydrocarbons recovered from those wells. In order to be eligible for the credit, the taxpayer must employ certain tertiary recovery methods, such as miscible fluid replacement, steam drive injection, microemulsion, *in situ* combustion, polymer-augmented water flooding, cyclic steam injection, alkaline flooding, carbonated water flooding, and immiscible carbon dioxide replacement.

– *Alternative Fuel Production Credit*. This tax credit provision applies to the production of alternative (or nonconventional) fuels. It is the largest energy tax credit and stems from Section 29 of the Internal Revenue Code. Section 29 was established by the Crude Oil Windfall Profits Tax Act of 1980. At the end of fiscal year 1999, the qualifying fuels had to be produced from specified wells drilled or certain facilities placed in service between January 1, 1980, and December 31, 1992, and sold through the year 2002. The value of the credit was an estimated $810 million for fiscal year 1999, making the Alternative Fuel Production Credit the largest energy-related tax expenditure. The qualified fuels are: oil produced from shale and tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass; liquid, gaseous, or solid synthetic fuels produced from coal; fuel from qualified processed formations or biomass; and, steam from agricultural products.

The tax credit appears to have had a substantial impact on the production of alternative fuels. Initially, it stimulated the development of nonconventional gas wells, but the early rates of growth were not sustained through the mid-1990s, as the 1992 deadline slipped further into the past. According to one study, in 1992, just before the deadline when newly drilled wells would no longer be eligible for the tax credit, 78 percent of gas wells completed were drilled for the exploitation of gas in coal seams, tight sands, and shale oil. The following year, their share had fallen to 61 percent. Although tight gas formations volumetrically account for the greatest share of U.S. nonconventional energy production, coalbed methane production has been affected most by the credit in recent years. Coalbed methane recovery totaled only 91 billion cubic feet in 1989 out of total U.S. gas production of 17 trillion cubic feet. By 1994 it had risen to 1.0 trillion cubic feet, or 5 percent of U.S. production. Since then, growth in coalbed methane recovery has been less dramatic. Its share of the market reached 7 percent in 1999, which is the latest year for which production data are available. The majority of production takes place in Colorado, New Mexico, and the Black Warrior Basin of Alabama.

- *Investment Credit for New Technology*. This credit formerly included a wide variety of items, but now it is limited to investment in solar and geothermal energy facilities. The Investment Credit for New Technology, also known as the Investment (Business) Energy Tax Credit, was valued at $30 million for fiscal year 1999. The Energy Tax Act of 1978 established a 10-percent investment tax credit for solar photovoltaic projects, as well as a 15-percent energy tax credit added to an existing 10-percent investment tax credit for solar thermal and wind generation facilities. The Tax Reform Act of 1986 eliminated the 10-percent investment tax credit and extended the energy tax credit to 1988, but it reduced that credit from 15 percent to 10 percent and eliminated wind as a candidate for any credits. The business tax credit was extended on a year-to-year basis until 1992, when passage of the Energy Policy Act of 1992 made the 10-percent business credit for solar (photovoltaic and thermal) and geothermal permanent. The Energy Policy Act of 1992 also provided a credit of 1.5 cents per kilowatthour for electricity produced from renewable resources such as wind and biomass, which expired on June 30, 1999, but was later extended through 2001.

- *Production Credit for Alcohol Fuels*. The Production Credit for Alcohol Fuels is the only income tax expenditure for which there is also a preferential excise tax, in the form of an exemption. Motor fuels containing at least 10 percent alcohol are exempt from 6.0 cents of the per-gallon Federal excise tax on gasoline, diesel fuel, and other motor fuels on a prorated basis. The income tax credit is 60 cents per gallon for alcohol used as a motor fuel and can be taken in lieu of the excise tax exemption. (For ethanol-based alcohol fuels, the excise tax exemption is 5.4 cents, and the credit equals 54 cents per gallon.) The income tax credit is granted to producers of alcohol fuels, defined as distributors who blend the alcohol and motor fuels. The credit may differ from 60 cents, depending on the proof of the alcohol. A new Federal income tax credit of an extra 10 cents per gallon is also available to eligible small producers of ethanol. Federal financial incentives for alcohol-based fuels in the transportation sector, strictly speaking, are limited to ethanol. The main use of ethanol is for gasohol, a blend of 90 percent unleaded gasoline and 10 percent ethanol, E10. The alcohol fuels income tax expenditure and preferential excise tax programs affect not only the motor fuels industry but other industries and the environment as well. The alcohol fuels industry can exist for motor fuel purposes only with the aid of Government subsidies because the price of alcohol fuels otherwise would not be competitive with gasoline or other alternatives. Because of the tax incentives, gasoline/ethanol blends account for somewhat less than one-tenth of U.S. motor fuel consumption and production.

The alcohol fuels income tax credit was not used to any significant degree until 1999, and in fiscal year 1999 it amounted to only $15 million, a value that could reflect the initial use of the new "small producers of ethanol" credit.

Income-Reducing Measure. The Percentage Depletion Allowance is the only energy-related tax expenditure that reduces taxable income. Independent oil and gas producers and royalty owners, and all producers and royalty owners of certain other natural resources, including mineral fuels, may take percentage depletion deductions rather than cost depletion deductions to recover their capital investments. Under cost depletion, the annual deduction is equal to the reduction in the remaining volume of the resource that results from the current year's additional production. In fiscal year 1999, the reduction in tax revenue totaled $260 million for oil, gas, and coal. (Small reductions for uranium, oil shale, and geothermal energy are included in the values for coal.)

The Alternative Minimum Tax Provision of the Energy Policy Act of 1992 reduced the tax burden on oil and gas producers and royalty holders by repealing, for them, excess percentage depletion tax adjustment for oil and gas for taxable years beginning after December 31, 1992. Excess preferences were preferences added back to the regular tax base in calculating income tax liabilities under the Alternative Minimum Tax System. The Alternative Minimum Tax System has been in effect since 1986. Its purpose is to ensure that all individuals or business entities that benefit from certain exemptions within the tax code pay at least a minimum amount of tax. One effect of the tax, initially, was to reduce the value of percentage depletion.

Alcohol Fuels Excise Tax Preference. All but one of the tax expenditure provisions reviewed here include Federal income taxes that are applied preferentially to energy. The exception is the partial exemption from Federal energy excise taxes that benefits alcohol fuels, the alcohol fuels excise tax preference. Its expected fiscal year 1999 value was $725 million.

Table 4. Estimated Revenue Losses from Federal Energy Tax Expenditures by Type of Expenditure and Form of Energy, Fiscal Year 1999
(million 1999 dollars)

Tax Expenditures	Oil	Natural Gas	Coal	Oil, Gas, and Coal Combined	[illegible]	Other Energy	Certain Energy Facilities	Total
Preferential Tax Rates								
Capital Gains Treatment of Royalties on Coal	0	0	65	0	0	0	0	65
Tax Deferrals								
Expensing of Exploration and Development Costs	NA	NA	NA	-70	0	0	0	-70
Exception from Passive Loss Limitation for Working Interests in Oil and Gas Properties	18	18	0	0	0	0	0	35
Tax Credits								
Enhanced Oil Recovery Credit .	160	0	0	0	0	0	0	160
Alternative Fuel Production Credit	0	810	0	0	0	0	0	810
New Technology Credit	0	0	0	0	0	0	30	30
Alcohol Fuel Credit	0	0	0	0	15	0	0	15
Income-Reducing Measure								
Excess of Percentage Over Cost Depletion	NA	NA	NA	260	0	0	0	260
Total Before Component Interactions	178	828	65	190	15	0	30	1,305
Alcohol Fuels Excise Tax	0	0	0	0	725	0	0	725

Tax Expenditures Applied to Energy Transformation and End Use

Energy transformation and end use tax expenditures apply to: the Exclusion of Interest on Energy Facility Bonds; the Exclusion From Income of Conservation Subsidies Provided by Public Utilities; and the Tax Credit for Clean-burning Vehicles. These expenditures totaled $270 million in 1999 (Table 5).

Exclusion of Interest on Energy Facility Bonds. The largest source of tax expenditures for end-use energy is the exclusion from gross income of interest on private activity bonds issued by State or local governments to finance certain energy facilities, often built by investor-owned utilities, from Federal taxation. The resulting loss of tax revenues in 1999 amounted to $110 million—the amount of Federal income tax that would have been paid on interest earnings from taxable bonds for energy facilities that are otherwise similar to those that are tax free (Table 5).

Exclusion from Income of Conservation Subsidies Provided by Public Utilities. The second largest tax expenditure for end-use energy in 1999 consisted of a Federal tax exemption for subsidies provided by public utilities to non-business customers to reduce the costs of energy conservation measures. This exclusion was estimated at $80 million in 1999.

Tax Credit and Deduction for Clean-Burning Vehicles. This tax expenditure consists of a tax credit of 10 percent for purchases of electric vehicles. The credit is capped at $4,000. Owners of clean-fuel storage facilities are also eligible for the credit. The value of this credit in 1999 was $80 million in terms of revenue lost.

Table 5. Estimated Federal Energy Tax Expenditures for Energy Transformation and End Use by Type of Expenditure, Fiscal Year 1999
(million 1999 dollars)

Expenditure	Revenue Loss
Exclusion of Interest on Energy Facility Bonds	110
Exclusion from Income of Conservation Subsidies Provided by Public Utilities	80
Tax Credit and Deduction for Clean-Burning Vehicles	80
Total	270

Analysis of Potential Incentives for Energy Efficient Equipment

As an example of the further use of tax credits for energy efficiency and renewables, we cite a study EIA produced at the request of the U.S. House of Representatives, Committee on Government Reform, Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs. EIA conducted an analysis of the potential impacts of the Climate Change Technology Initiative (CCTI), relative to the baseline energy projections in its *Annual Energy Outlook 2000* (*AEO2000*). CCTI, as proposed, included $201 million in fiscal year 2001 for tax incentives for encouraging energy efficiency improvements and renewable technologies for buildings, light-duty vehicles, and electricity generation. CCTI also included additional funding for research, development, and deployment for energy-efficient and renewable technologies and appliance efficiency standards; however, these are not analyzed here.

CCTI proposed investment tax credits for buildings and vehicles to reduce the initial costs of more energy-efficient and renewable technologies to consumers, a change in the depreciable life for distributed power property, and production tax credits for renewable generation technologies. The proposed tax credits were generally to be in effect for only a few years. The purpose behind this program and its phase-out was to encourage the widespread market penetration of more efficient and renewable energy-using technologies before the credits were to be withdrawn.

The proposed tax credits included:

- *Energy-Efficient Homes*—a $1,000 tax credit for new homes built from 2001 through 2003 that are at least 30 percent more efficient than the standard specified in the 1998 International Energy Conservation Code (IECC) and a credit of $2,000 for homes built from 2001 through 2005 that are at least 50 percent more efficient than the IECC standard.

- *Energy-Efficient Equipment in Homes and Buildings*—20-percent tax credits for electric heat pump water heaters, natural gas heat pumps, and fuel cells, meeting specified efficiency levels, purchased from 2001 through 2004. The credits are capped at $500 per kilowatt for fuel cells, $1,000 per unit for natural gas heat pumps, and $500 per unit for electric heat pump water heaters.

- *Rooftop Solar Systems*—a 15-percent tax credit for rooftop photovoltaic systems installed between 2001 and 2007 and solar water heating systems, excluding swimming pools, installed from 2001 through 2005. The credit is capped at $2,000 for photovoltaic systems and $1,000 for solar water heating systems.

- *Electric Vehicles and Fuel Cell Vehicles*—the current 10-percent tax credit, subject to a $4,000 cap, for the purchase of qualified electric vehicles and fuel cell vehicles is scheduled to begin to phase down in 2002, phasing out completely in 2005; however, this proposal would extend the credit at its full level through 2006.

- *Hybrid Vehicles*—tax credits for qualifying hybrid vehicles, including cars, minivans, sport utility vehicles, and pickup trucks, purchased from 2003 through 2006, ranging from $500 to $3,000, depending on the vehicle's design performance.

- *Wind Generation*—the current tax credit of 1.5 cents per kilowatthour, adjusted for inflation, for systems placed in service from 1994 through 2001, would be extended through June 30, 2004, or through June 30, 2005, for systems under firm contract or under construction.

- *Biomass Generation*—the current tax credit of 1.5 cents per kilowatthour, adjusted for inflation, for systems using dedicated energy crops placed in service from 1993 through 2001, would be extended through June 30, 2004, or through June 30, 2005, for systems under firm contract or under construction. Systems using nondedicated crops placed in service from 2001 through 2005 would receive a 1.5-cent-per-kilowatthour credit for ten years, and systems using nondedicated crops placed in service before 2001 would receive a 1.0-cent-per-kilowatthour credit, adjusted for inflation, from 2001 to 2003. A new 0.5-cent-per-kilowatthour tax credit, adjusted for inflation, would be added for biomass-fired electricity generated by coal plants using biomass co-firing from 2001 through 2005.

- *Landfill Gas Generation*—a new tax credit of 1.0 cent per kilowatthour for landfills subject to EPA's New Source Performance Standards (NSPS) and a 1.5-cent-per-kilowatthour credit for landfills not subject to the NSPS for systems placed in service from 2001 through 2005, or through 2006 for facilities under construction or with a construction contract in place to be completed in 2006.

Table 6 shows the projected impacts of the tax credits on energy consumption, which generally increase through 2005 as the more advanced technologies become available and gradually penetrate the market. In 2010, the tax credits for buildings and transportation were estimated to reduce primary energy consumption by 42.5 trillion British thermal units (Btu), or 0.04 percent, relative to the consumption of 111 quadrillion Btu projected in the *AEO2000* reference case. In addition, the tax credits for renewable generation were estimated to reduce fossil energy consumption for electricity generation by 48.7 trillion Btu, or 0.04 percent of total energy consumption.

Table 6. Projected Reductions in Primary Energy Use for CCTI Tax Credits, 2002-2010
(trillion Btu)

CCTI Tax Credits	2002	2003	2004	2005	2010
Buildings					
- Energy-Efficient Equipment	3.1	4.8	6.7	6.6	5.9
- Energy-Efficient New Homes	0.8	2.1	5.1	9.8	9.5
- Rooftop Solar Equipment	<0.01	<0.01	<0.01	<0.01	<0.01
Transportation					
- Electric, Fuel Cell, and Hybrid Electric Vehicles	0.5	2.5	5.2	8.6	27.1
Renewable Generation	91.4	103.5	127.5	150.9	48.7
Total	95.8	112.9	144.5	175.9	91.2

Note: For the renewable generation tax credits, the change represents the reduction in fossil energy use for electricity generation.

Although the tax credits reduce the initial cost to the purchasers of the applicable equipment, the analysis assumed that consumers would continue to make decisions as indicated by EIA's analysis of historical trends. The tax credits reduce the initial cost of purchasing more efficient equipment; however, by themselves, they were not of sufficient magnitude to overcome observed consumer reluctance to purchase more expensive equipment with long payback periods. Most consumers are willing to invest in more efficient, but more expensive, equipment if the higher initial costs are offset by lower fuel expenditures within a period of several years.

Tax credits of longer duration and/or higher value could encourage greater penetration of the technologies by making them more economically competitive. The timing of the tax credits is also a key factor in their impacts. For example, the proposed tax credit for fuel cell vehicles was extended through 2006, but the technology was, by EIA's assumption, not commercially available until 2005. The duration of the tax credit is also an important factor. For example, when the buildings equipment tax credits expire in 2004 as proposed in CCTI, the impact of the credits would be reduced, because some of the new, more efficient equipment would begin to need replacement and would be replaced by equipment of lower efficiency. Without the tax credit, the more efficient equipment would no longer be economic. The impact is less in 2010 than in the earlier years because most other tax credits expire in 2005. The transportation tax credits have a small impact in the earlier years because of the limited availability of eligible technologies; however, later in the period the impacts are larger because the tax credits encourage the penetration of advanced technology vehicles.

Summary

Energy tax expenditures and direct expenditures for fiscal year 1999, the latest available data, represented less than one percent of total energy expenditures. Energy tax expenditures can have a substantial impact if they are of sufficient size and duration, for example, the Alternative Fuel Production Credit. However, as the CCTI analysis shows, the amount of impact can be quite small if the size and duration of the tax incentives are not sufficient to induce consumer change or make the technology cost effective. Programs that offer small incentives for products for which there are large existing markets tend to function mostly as transfer programs; that is, their market impacts are negligible, and for the most part they simply redistribute funds from one part of the economy to another, with the Government acting as the intermediary. More often, Federal energy incentives offer relatively large payments to producers using specific energy technologies that otherwise would be uneconomical. In these cases, the effects on the larger markets are small, but the impacts on the use of particular technologies may be significant.

Wyden Q's #4

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QUESTION FROM SENATOR WYDEN

Options for Ensuring Renewable Energy Development

Q4. The Administration's Energy Plan recognizes that our country needs a diverse set of energy resources and I think there's bipartisan consensus in support of that view in the Congress. I think where the consensus may break down is how you go about ensuring our country has a diversity of energy sources. Certainly, we want to try incentives to encourage development of alternative energy sources, but incentives don't guarantee that these alternative energy sources are developed. What do you do besides incentives to guarantee that alternative energy sources are developed for the future? Should we have a portfolio standard to ensure that at least a minimum percentage of the energy mix comes from renewable sources?

A4. It is pleasing to note your additional confirmation that there is bipartisan Congressional consensus on the need for a diversity of energy sources, as called for in the President's National Energy Policy. I am also pleased to hear your support for incentives to encourage development of alternative energy sources. Of the 13 recommendations for renewable and alternative energy contained in the President's National Energy Policy (NEP), five recommendations address tax incentives. These five tax incentives are also contained in the energy legislation, H.R. 4, which passed the U.S. House of Representatives this summer. Also found among the recommendations in the National Energy Policy are a mix of regulatory and research and development recommendations that will support a diverse energy mix. A key recommendation is for the Secretary of Energy to conduct a review of renewable energy and alternative energy research and development programs. We hope to complete that review shortly, thus allowing DOE to propose FY03 funding levels for research and development that are appropriately performance-based and are modeled as public-private partnerships. Past DOE-sponsored research and development has contributed significantly to greater use of alternative and renewable energy. We anticipate that our review will allow an even greater use of these energy forms through focused R&D that leads to accelerated technology results.

Many states have already chosen to implement renewable and alternative portfolio standards. In fact, DOE estimates that existing state laws and policies will result in more than a doubling of non-hydro renewables by 2012. The forecasted 8,400 MW of additional capacity is expected to be driven by 5,500 MW of state purchase obligations (including renewable portfolio standards) and 2,900 MW to be developed through system-benefits charges and other renewable energy funds. It is premature at this time to determine whether establishing a national portfolio is appropriate.

Assistant Secretary's Initials:
Office Director's Initials:
DAS Initials:
PSO Initials:
Date: August 31, 2001

Preparation Lead: EERE
Preparation Team: Larry Mansueti
Reviewed by: Patrick Booher

Date Question Received: August 29, 2001

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Wydw 3

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QUESTIONS FROM SENATOR RON WYDEN

Regaining U.S. Renewable Energy Leadership

Q3. The United States is the most advanced country in the world and the leader in many areas of technology, but renewables is not one of them. New wind turbines that are currently being installed in the Pacific Northwest are designed and built in Denmark. Europe and Japan are the leaders in renewable energy technologies and what can this Administration do to help U.S. manufacturers regain leadership in this field.

A3. The picture is not as bleak as suggested, and varies by renewable technology. For example, according to the American Wind Energy Association, total installed capacity of wind technology was 17,300 MW by the end of 2000. Of this, Germany has 6100 MW, the United States 2554, Denmark 2300, Spain 2250 MW. Based on announced industry development plans and construction starts, we project at least 1500 MW of newly installed wind capacity additions in 2001 in the United States. The manufacturers with the largest sales in 2000, the latest year for which we have data, were from Denmark and Germany. However, one U.S. firm, Enron Wind Corp. is among the top five in the world. In the 1980s, wind installations in California were divided about evenly among U.S. and overseas manufacturers. When the wind energy investment credit was allowed to expire in the mid-1980s, sales momentum continued in the United States at a reduced pace. That momentum ceased in 1990 as Interim Standard Offer contracts in California were completed. During this period, one major U.S. manufacturer and several smaller ones went bankrupt because of poor market conditions. Significant capital investment and mandatory purchase incentives became available in Denmark as early as 1979 and in Germany in the late 1980s. This led to European capacity exceeding the capacity installed in the United States by the 1994. U. S. technology is just as advanced as that of Europe. The on-again, off-again market incentives in the United States have been much less effective than the steady incentives in European countries. In the United States; restoring world technology leadership requires market continuity through the extension of the Production Tax Credit that expires at the end of 2001 (as supported by the National Energy Policy Plan), and support for the Administration's budget request.

In the case of photovoltaics, the U.S. is the world leader despite intense international competition. This is evidenced by the establishment of several U.S. world record solar cell efficiencies that have been achieved during the last five years, and by the rapidly expanding domestic photovoltaic industry.

However, because of comparatively inexpensive fossil fuel and nuclear energy resources, the U.S. does not presently experience the urgency for renewable energy development that is experienced by nations such as Denmark and Japan. Consequently, the U.S. does not have the intense national priority for renewable energy development that is seen in these and other countries with similar circumstances. For example, Japan – which must import essentially all of its fossil energy, invests over six times more in R&D funding than the United States. Through continued focus on both fundamental and applied R&D, in collaboration with industry, we will help the U.S. achieve greater leadership in the development of advanced renewable energy technologies which, in turn, will lead to increased sales.

Assistant Secretary's Initials: Preparation Lead: EERE

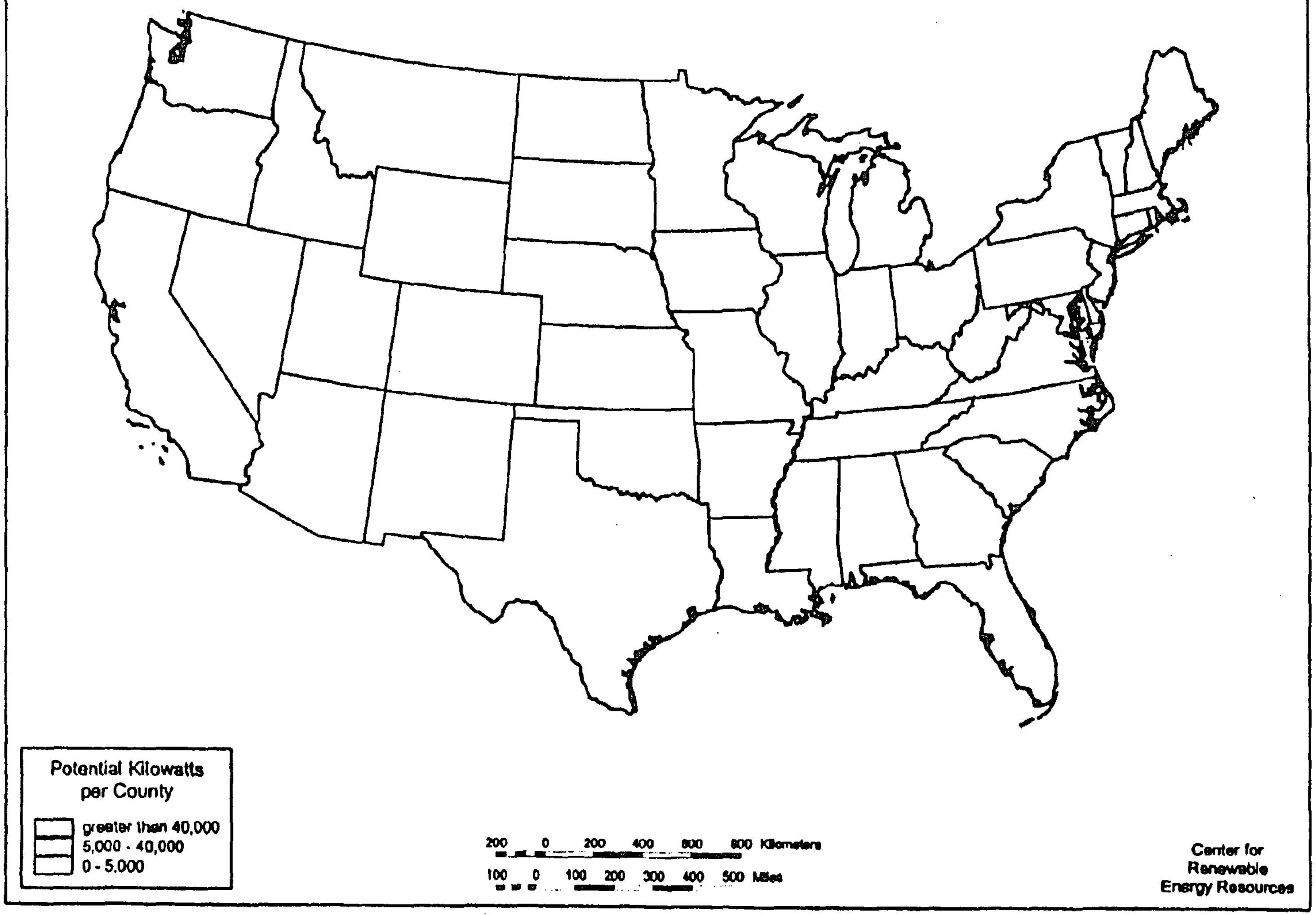
23184

Office Director's Initials:
DAS Initials:
PSO Initials:
Date: August 31, 2001

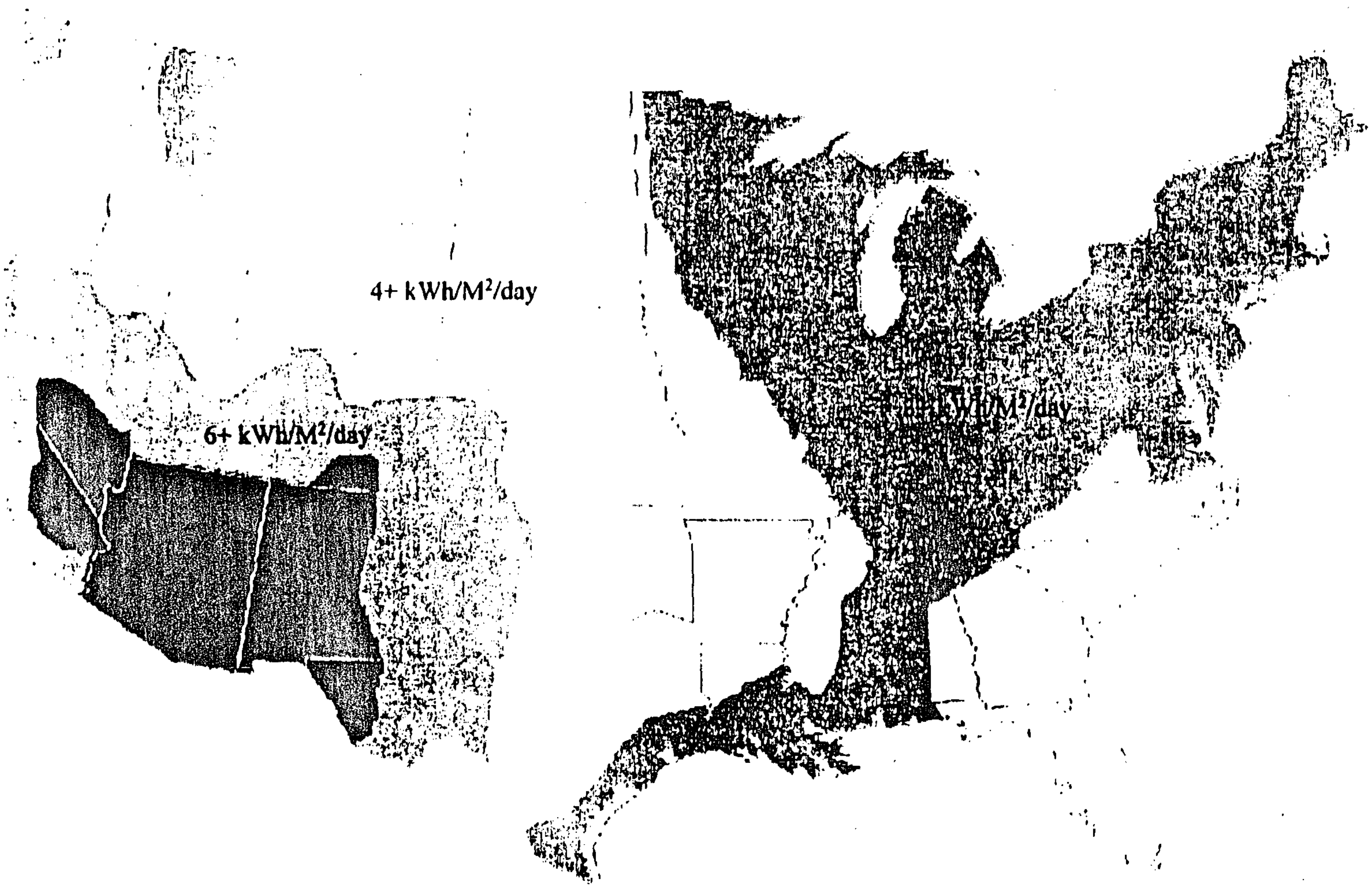
Preparation Team: Jack Cadogan
Reviewed by: Patrick Booher

Date Question Received: August 29, 2001

Biomass and Biofuels Resource Potential

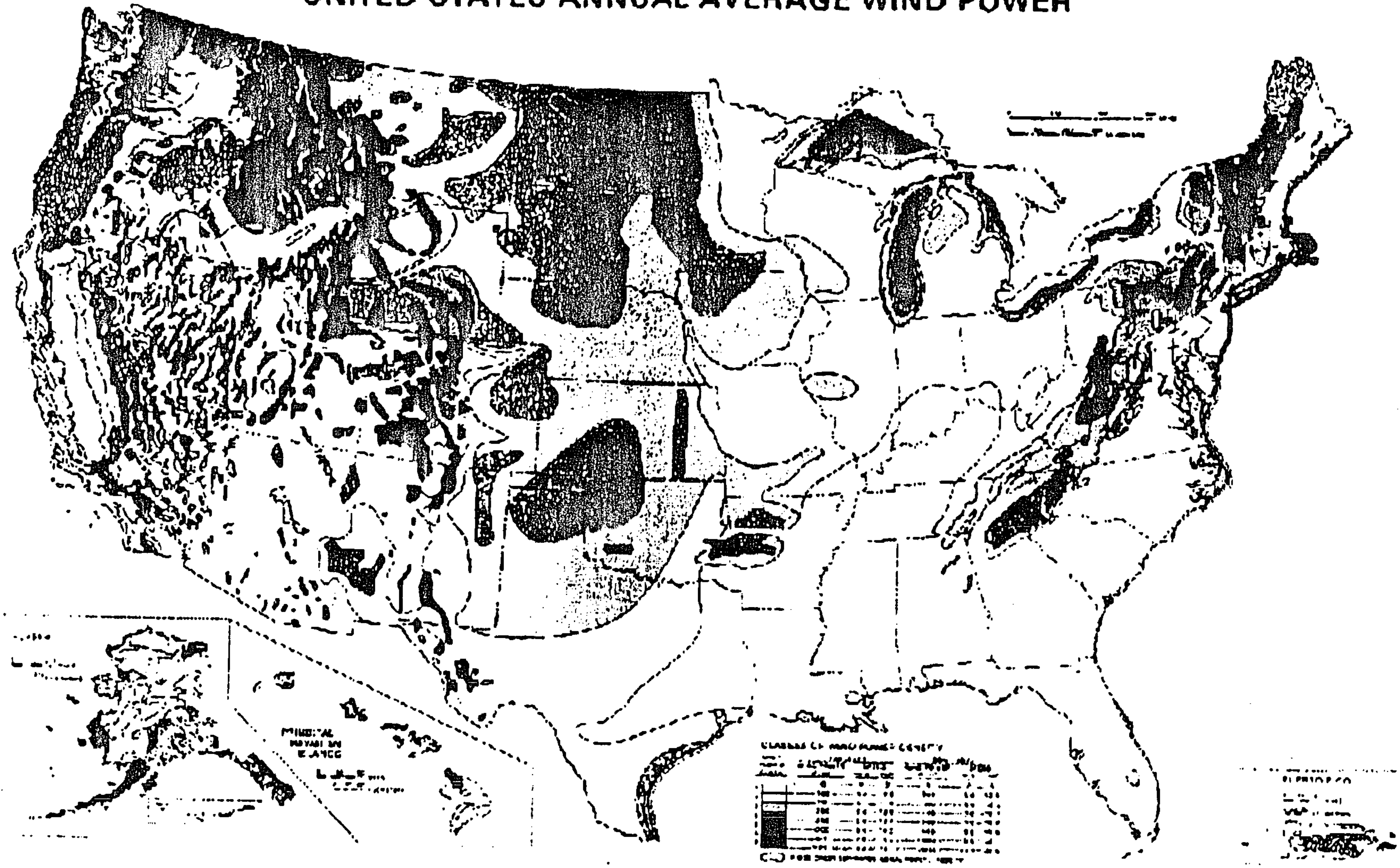


Solar Insolation Resource



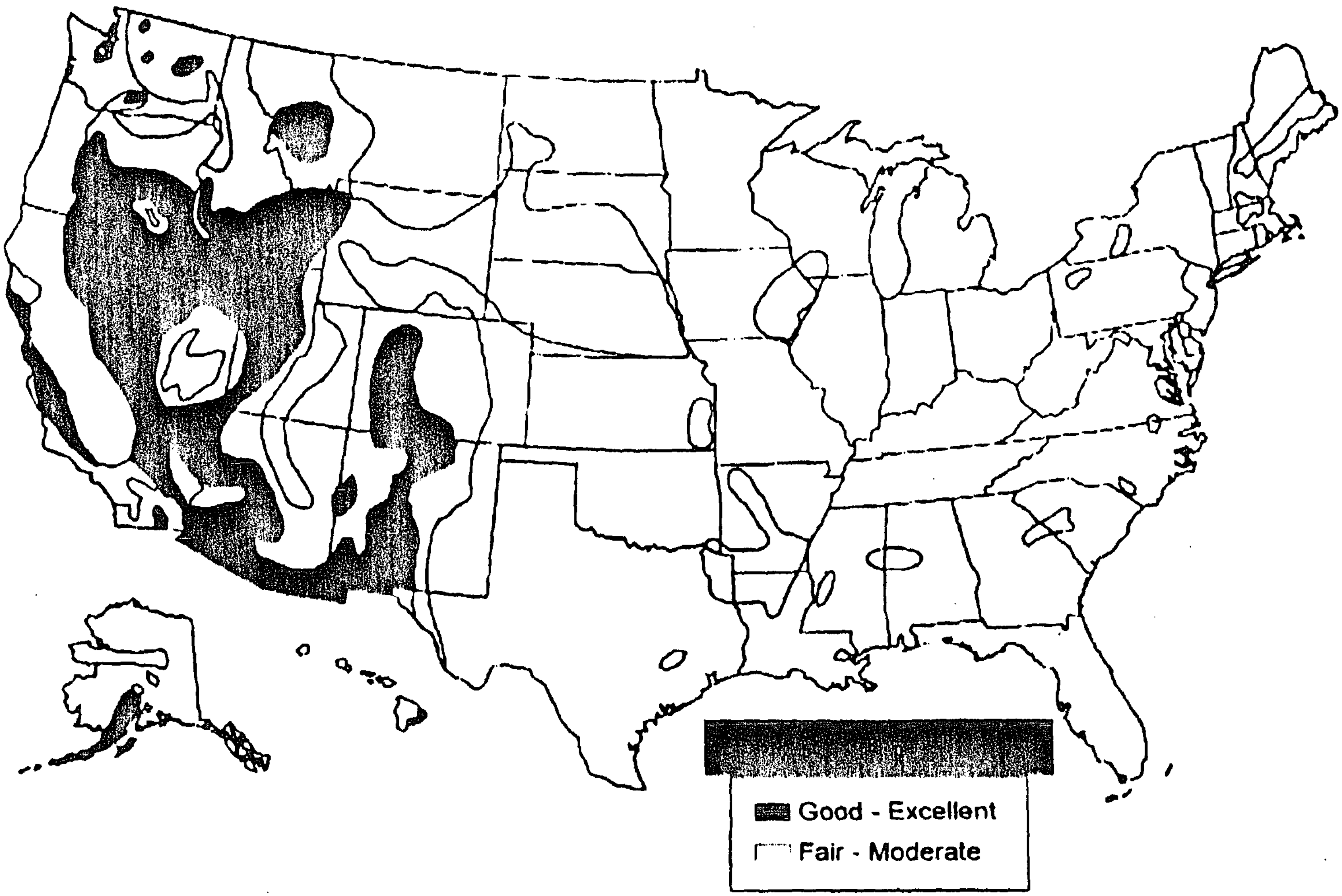
Source: National Renewable Energy Lab Center for Renewable Energy Resources

UNITED STATES ANNUAL AVERAGE WIND POWER



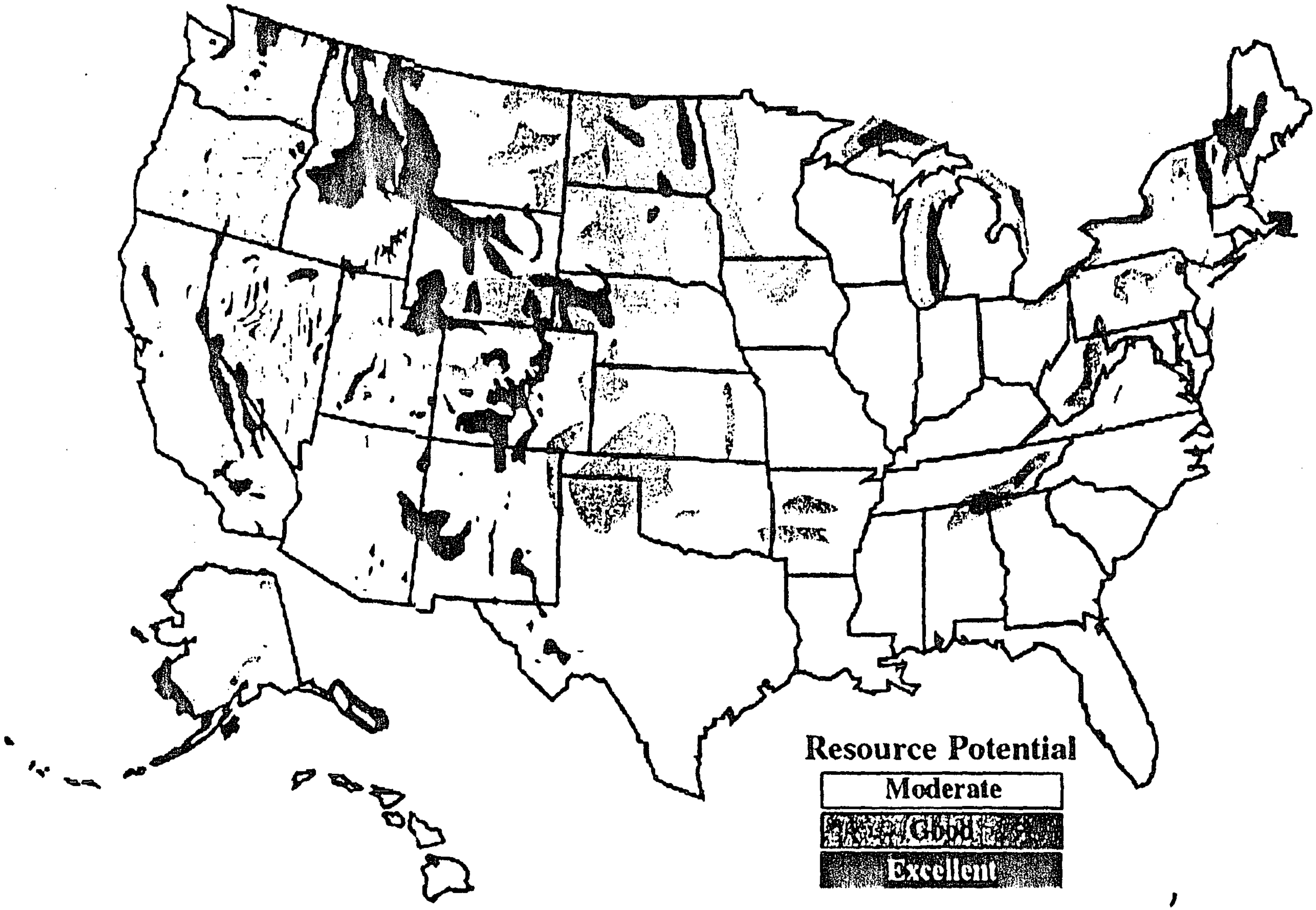
Source: National Renewable Energy Lab Center for Renewable Energy Resources

Geothermal Resources



Source: National Renewable Energy Lab Center for Renewable Energy Resources

Wind Resources



Source: National Renewable Energy Lab Center for Renewable Energy Resources

UNIDO Study Tour
Agenda Revised
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Background and Possible Agenda for Visit by PRC Delegation under a UNIDO Study Tour

Composition: Delegation to be led by Mr. Zhu Baozhi, Deputy Director General, State Development Planning Commission and comprised of representatives from MOST, the Administrative Center for China's Agenda 21 the Policy Research Center for Environment and Economic of the State Environmental Protection Administration and the Provincial Development Planning Commissions for Fujian, Zhejiang and Henan

Dates: Arriving in Washington on August 6 and departing for Canada on August 15.

Purpose: Capacity building tour under UNIDO project begun in 1999 with the SDPC on sustainable industrial development. Includes a number of study tours; the one to the US and Canada is focused on energy and the environment. At DOE, the Delegation hopes to visit with Fossil Energy, the Policy Office, the Energy Information Administration, and has expressed an interest in briefings on US energy efficiency and renewable energy programs. They also will be seeking to meet with the Vice President's Energy Task Force, EPA, congressional staff on environment committees, the NRDC, Resources for the Future, and the California Governor's Office. The goals of the Study Tour are to: discuss and share experiences about sustainable energy development such as renewable energy development and clean coal technology development; learn lessons from energy conservation in the fields of industrial facilities, residential sector and transport sector; learn about government programs to address global climate change; review success stories in natural resource conservation and management (such as water resource management); learn about experiences in properly handling remote regions and conserving the environment; share experiences in financing energy and environmental infrastructure projects; learn about effective government policy and supportive measures for developing the environmental industry.

Possible Agenda:

- Key Aspects of the National Energy Policy report: **Overview by the Office of Policy**
- U.S. Clean Coal Technology Program and Highlighting DOE Cooperation in this area with China: **Overview by the Office of Fossil Energy**
- U.S. Energy Efficiency Policy and Programs: **Overview by Office of Policy and representative from Office of Energy Efficiency and Renewable Energy**
- Highlights of USG Energy Efficiency Cooperation with China: **Office of Energy Efficiency and Renewable Energy**
- Highlights of U.S. Renewable Energy Programs and Strategy: **Representative from the**

Office of Energy Efficiency and Renewable Energy

- USG Strategy to Respond to Global Climate Change: **Representatives from the State Department Office of Oceans, Environment and Science and Climate Expert from DOE Office of Policy**

- Natural Resource Conservation and Management, **focusing on Water Resource Management and Handling of Remote Regions , possibly by representative from the US Department of the Interior**

- Government Policy and Support Measures for Developing the Environmental Industry, **overview by expert from the Environmental Protection Agency**

- California Electricity Situation, one-two hour briefing by experts from DOE's **Energy Information Administration**

Transmission prob map

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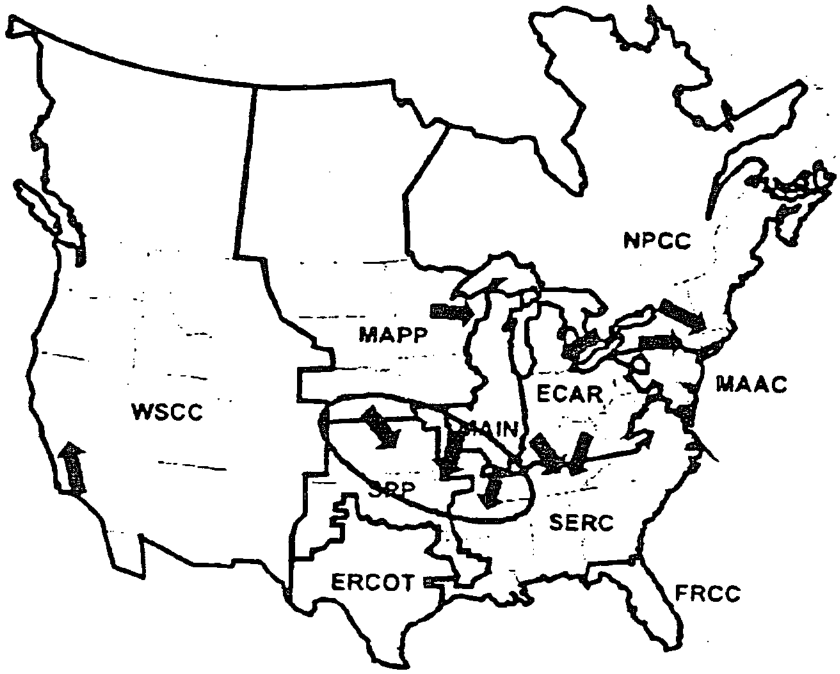

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STRATEGIC PROGRAM REVIEW WORKBOOK

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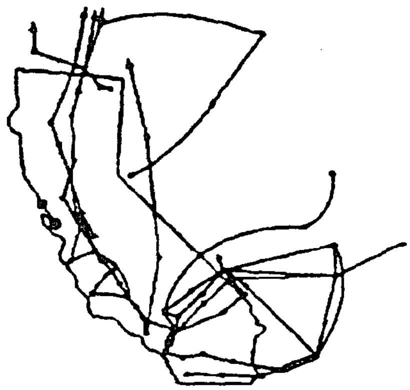
MAJOR ELECTRIC
TRANSMISSION LINES



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Testimony of David K. Garman
Assistant Secretary, Energy Efficiency and Renewable Energy
Department of Energy
before the
Committee on Energy and Natural Resources
United States Senate
July 13, 2001

Thank you for this opportunity to testify on S. 352; Title XIII of S. 597; Sections 602-606 of S. 388; S. 95; and S. J. Res. 15. These measures, of course, all relate to the improvement of energy efficiency.

Energy efficiency is an important part of the Administration's overall energy policy. The National Energy Policy (NEP) document released May 16 dedicates an entire chapter to energy efficiency, and another chapter to the subject of renewable energy. Moreover, 54 of the NEP's 105 recommendations relate directly or indirectly to the importance of increasing our energy efficiency or increasing our use of clean, renewable energy.

When thinking about efficiency, it is useful to consider the nature of our energy systems. The charts on display look at electricity flow, which represents about a third of our total energy use. If we were to increase end-use efficiency by 20%, thereby saving the equivalent of 2.1 quadrillion BTUs (quads) of end-use energy, we would actually save 6.7 quads of energy inputs at the power plant due to conversion losses in generation and the losses associated with transmission and distribution. This illustrates why increasing end-use efficiency is very important... but why it should not constitute the sum total of our efforts. If we can employ technologies that increase end-use efficiency <u>and</u> supply efficiency by 20%, then we could save 14.7 quads of energy inputs, resulting in lower costs and fewer emissions.

This is something that your Committee clearly recognizes, Mr. Chairman, as evidenced by your hearings today and those scheduled for next week. Although today's focus is on achieving end-use efficiency, next week the hearings will look beyond end-use savings to the removal of barriers to distributed generation and other technologies that can help us make our overall energy generation, transmission and distribution systems more efficient. I commend you for this approach, which is in close agreement with the approach embodied in the President's National Energy Policy.

Today, I want to take this opportunity to announce that we are launching a new analytical effort at the Department of Energy to better understand and track trends in national energy intensity. Surprisingly, DOE has never done this before in a sustained and systematic manner. We envision that this effort can eventually result in national goals for energy efficiency improvements made possible through technological advances and cooperative efforts with industry, state and local governments, consumers, utilities,

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and others. We are doing this in direct response to the recommendation in the National Energy Policy that energy efficiency be pursued as a national priority.

With respect to the specific provisions in legislation before the Committee today, I would note that they are all well intentioned, and with some modifications, the Administration is likely to be in a position to support many of them if they are part of a balanced, comprehensive approach that also addresses supply and infrastructure issues contained in the National Energy Policy document.

However, I must add an important note of caution. It is, of course, relatively easy to authorize new funding, but relatively difficult to appropriate it. The most generous of the bills before us would authorize $500 million annually for weatherization, $230 million annually for energy efficient schools, $125 million annually for State Energy Programs, and would require an expenditure of roughly $180 million in appropriated funds to create an Energy Bank to finance energy savings measures in federal agencies. That adds up to well above a billion dollars. The comparable level of appropriated funding in my 2001 budget was $153 million for weatherization and $38 million for State Energy Programs, or about $191 million. (I am not including the $3.4 billion that would be authorized under one of the bills for Low Income Home Energy Assistance Program, as that is not one of DOE's programs.) As we work together in the weeks and months ahead to determine the appropriate authorization levels for these programs, I urge that there be some linkage between the authorized levels and a realistic expectation of the eventual appropriations that will follow. We also urge Congress to consider new revenue streams, such as bonus bid payments and royalties produced from energy production on federal land, as sources of funding for some of these initiatives.

Weatherization assistance

The Weatherization assistance program provides services to eligible low-income persons, with emphasis on elderly persons with disabilities and children. States including the District of Columbia voluntarily participate. Up to an average of $2500 per dwelling unit may be spent for purchase and installation of eligible weatherization materials, and energy audits are used to ensure that the measures employed in a given home are cost-effective.

The Weatherization Assistance Program has reduced the heating and cooling costs of low-income households by weatherizing more than 5 million homes since the program's inception in 1976. The President has proposed $1.4 billion in additional funding for weatherization over the next ten years. The President's budget for FY 2002 proposed a $120 billion increase from $153 million to $273 million, which will weatherize 123,000 homes—an increase of 48,000 homes over the number weatherized in the prior fiscal year. We were pleased to see that the House provided full funding for this request in its Interior Appropriations Bill. The Senate Appropriations Committee, however, provided only half the President's requested increase—$60 million—to bring the program to a level of $213 million. [ADD INFO AS NEEDED TO REFLECT SENATE FLOOR ACTION]

We support an authorization level that accommodates the President's requests for increases in this program. Our recommended ramp-up of the program anticipates spending levels for the program as outlined in the table below.

Fiscal Year	WAP Base	Initiative	WAP Total
2002	$153 million		
2003	$153 million		
2004	$153 million		
2005	$153 million		
2006	$153 million		
2007	$153 million		
2008	$153 million		
2009	$153 million		
2010	$153 million		
2011	$153 million		
10 Year Total	$1,683 million		

Section 422 of the Energy Policy and Conservation Act statute authorizes "sums as may be necessary" for the weatherization assistance program. Section 3 of S. 352 (Bingaman) would increase the weatherization program authorization to $310 million for each of the fiscal years through 2005.

Section 603 of S. 389 (Murkowski) would also increase the program authorization levels to $250 million in FY 2002; ramping up to $500 million in FY 2005. We note that the authorization levels in the S. 389 for FY 2002 would fall $23 million short of the President's request. Unless modified, we would be unable to support this provision. Section 603 of S. 389 would also expand the eligibility of low-income households from 125% of the poverty level to 150% of the poverty level. We are not certain that this change is needed since states may, under current law, elect to use LIHEAP eligibility criteria in administering the DOE weatherization program. The LIHEAP eligibility criteria gives states the option of using the 150% poverty level figure or a figure of 60% of a state's median income as a basis of eligibility.

State Energy Program

States voluntarily participate in the State Energy Program (SEP) by submitting grant applications with energy plans to DOE. States are required to contribute 20% matching contributions, and SEP funds are used to finance a variety of projects, including building codes updates, installing energy conservation measures, encouraging the use of clean fuel vehicles, and developing energy emergency plans.

The President's budget request for FY 2002 for State Energy Program funding was $38 million, a small increase over the comparable FY 2001 level. We are pleased that both the House and Senate Committees fully funded his request in their Interior appropriations bills. [UPDATE AS NEEDED]

Section 3 of S. 352 (Bingaman) would change the authorization levels for State Energy Conservation Grants from "such sums as may be necessary" to $75 million for fiscal years 2001-2005.

Section 604 of S. 389 (Murkowski) would also increase specify a higher authorization level for State Energy Conservation Grants compared to past practice in Congressional appropriations. S. 389 also appears to change the State Plan approval cycle from once a year to once every three years, a change that would streamline program administration at both the Federal and State levels. Finally, the Murkowski provision would appear to establish a goal of 25% improvement in a state's energy efficiency by 2010 (against a 1990 baseline).

This is probably an appropriate place to comment on the use of numerical goals in statutory language. Goals that are clearly defined and measurable can be quite useful. In the case of energy savings goals expressed under the Federal Energy Management Program (FEMP), the goals are expressed in terms of energy use per square foot of building space. This is a goal we can measure, understand, and pursue.

Unfortunately, the existing goal in section 364 of the Energy Policy and Conservation Act that S. 389 would amend has never been clearly defined. Is it per capita energy intensity? Is it energy use per unit of economic production? Should the goal be attributable to the actions of a State Energy Program, or should it also measure energy efficiency gains that occur as a consequence of market forces or structural changes in the economy? If the intent is to establish a goal that State Energy Programs can attribute to their activities, we can safely predict that you will hear the view from Governors and State Energy Officials that a 25% goal is unrealistic without substantial increases in appropriated funding.

I cannot tell you today what we believe the funding levels should be in subsequent fiscal years, as this is a component of both our ongoing 2003 budget formulation and a top-to-bottom strategic review that is now underway for each of the 31 programs in my office.

Energy Efficient Schools

Section 602 of the S. 389 (Murkowski) establishes an Energy Efficient Schools Program in the Department of Energy. Section 1302 of S. 597 (Bingaman) establishes a program within the Department of Education to promote energy efficient schools.

My office has several existing programs that speak to this issue. Through the "Rebuild America" Energy Smart Schools campaign, my office provides technical assistance for design and financing as well as conservation technology. We also do work in areas of alternative fuel school transportation and a number of supply side management strategies such as micro-cogeneration, combined heat and power, renewable energy and alternative fuel sources. While a great deal of what we do is applicable to schools, only $2-3 million worth of our work is directed specifically to schools, not including school-related expenditures under the State Energy Program.

State Energy Programs can already use existing resources to promote energy efficient schools, and of course those efforts must be cost-shared. We view cost sharing with our state partners as a good way to leverage federal resources and ensure that they are directed where they will do the most good. Therefore, it is our preference to use the existing State Energy Programs to promote energy-efficient schools rather than authorizing a new program whose chances of receiving significant funding from the appropriators may be questionable. As funds are available, they should be directed to existing programs that can achieve the desired goals we share.

If legislation is deemed necessary to provide greater federal emphasis on promoting energy-efficient schools, we recommend that the Department of Energy lead the effort in concert with the State Energy Offices. We do not believe that a Department of Education administered grant program as proposed in S. 597 would fully leverage the advantages that could be achieved through coordination with our existing energy efficiency programs and the ongoing efforts of the State Energy Offices.

Federal Energy Management Program (FEMP) Provisions

The Federal Government is the country's largest energy user, spending almost $8 billion annually on energy costs. We operate over 500,000 facilities and almost 600,000 vehicles worldwide. The President's National Energy Plan calls on Federal agencies to conserve energy and to reduce energy use during peak hours in areas where outages are likely. Since 1985, the federal government as a whole reduced energy use in its buildings by more than 20 percent in 1999 – thereby achieving its year 2000 goal one year early. Our most recent figures for FY 2000 places our reduction at 22% over the 1985 baseline. This represents a $2.2 billion energy savings, expressed in year 2000 dollars.

President Bush, in a May 3rd directive to Federal Agencies, asked that immediate steps be taken to reduce energy use, particularly peak demand in supply-constrained areas such as California. Agencies achieved some important results, including participation in a load reduction exercise on May 24th. During that exercise, 114 Federal facilities, representing 20 different agencies and roughly 80% of the federal load in California, demonstrated reductions in peak demand approaching 10%. To reduce overall demand in California, we have dispatched teams to 25 of the largest sites in California to identify the immediate no-cost/low cost opportunities for reducing demand. These teams are at work now, and we have asked them to report by July 31.

These efforts are important for practical reasons. But they are also important for symbolic ones. We can tell America it must use energy more efficiently... but if we fail to lead by example, we undermine our message.

It is our hope that energy efficiency in the federal realm will not be a short-term effort driven by current concerns about energy supply. Instead, we would like to work with you to build a new culture of energy savings that pervades the way that the Federal Government procures buildings, appliances, vehicles, and all of the other items we purchase.

Whenever the federal government builds a new building, we should strive to design and build it to achieve the "Energy Star" certification. When existing federal buildings are modernized, we should incorporate the energy and water conservation efforts that are cost effective over the life cycle of the facility.

Recently in Kansas City, DOE hosted a Federal Energy Management conference where hundreds of federal procurement officials, building engineers, and program managers gathered to learn the latest approaches to saving energy and money for the taxpayer. We are working to develop that new culture of energy savings among federal government procurement and buildings officials because it makes sense for the taxpayer and it is good for the environment. As an additional benefit, we also find that our workers prefer to work in a building that incorporates the latest energy savings technologies.

One of the keys to successful implementation of federal energy savings measures is through the use of Energy Savings Performance Contracts and Utility Contracts. These privately financed approaches are being employed to finance energy savings measures without using appropriated dollars. To date, Federal agencies have already leveraged more than $1.3 billion in private sector investment for projects that replace inefficient building systems with state-of-the-art equipment and, at the same time, save energy and money.

The Federal government can also make a difference by making smart purchasing decisions. The Federal government spends more than $10 billion each year on energy-using equipment. According to a recent study conducted by Lawrence Berkeley National Laboratory, the Federal government could save at least $120 million in annual energy costs by 2010 just by buying energy efficient products that are readily available. The joint DOE/EPA ENERGY STAR® program identifies energy efficient products so that all consumers, including Federal purchasers, can make informed decisions that save energy and money.

So we applaud the effort to address federal energy use in section 4 of S. 352 (Bingaman) and sections 605 and 606 of S. 389 (Murkowski), and would like to work with you to fashion a workable approach in this area. With respect to specific comments, I would offer the following:

Section 4 of S. 352 (Bingaman) would require federal agencies to undertake a comprehensive review of all practicable measures to conserve energy, water, or employ renewable energy resources and to implement measures to achieve 50% of the potential savings within 180 days. Candidly, a comprehensive review of all practicable measures that we could employ in 500,000 federal buildings, followed by the implementation of steps to achieve 50% of identified potential savings, could simply not be done in 180 days. Our challenge is to change the federal procurement culture, and we believe that will be a long-term effort.

S. 389 (Murkowski) would require agencies to reduce energy use per gross square foot by 30% by 2010 and 50% by 2020 relative to a 1990 baseline. The current goals, contained in the National Energy Conservation and Production Act, the Energy Policy Act, and Executive Order 13123 are to reduce energy use per gross square foot by 20% in 2000, 30% by 2005, and 35% by 2010 relative to a 1985 baseline. S. 389 represents an acceleration of these targets and a shifting of the baseline to the year 2000. Thus, it is a very ambitious goal. We believe we might be able to support such a goal were it contained in comprehensive legislation that also addresses the supply and infrastructure issues identified in the National Energy Policy document.

As mentioned earlier, Energy Savings Performance Contracts (ESPCs) are an important tool federal managers can use to achieve their energy savings goals without appropriated dollars. S. 389 (Murkowski) would extend authority for ESPCs five years, and S. 352 (Bingaman) would repeal the sunset provision entirely. Because we have achieved good results from the use of ESPCs and are working to expand their use, we believe we can support a complete repeal of the sunset provision, particularly if it is contained in comprehensive legislation that also addresses the supply and infrastructure issues identified in the National Energy Policy document.

S. 389 (Murkowski) would allow utility contracts, which are sole-source energy savings contracts entered into between federal facilities and the utilities that serve them, to increase from a maximum 10-year term to a maximum 25-year term. This is in line with the 25-year terms allowed ESPCs. However, 25-year ESPC contracts contain performance guarantees as well as provisions to ensure measurement and verification of energy savings. If Congress chooses to allow utility contracts to span 25 years, we believe there should be a requirement for guaranteed energy savings and assurances of performance in the longer-term utility contracts as well.

S. 352 (Bingaman) would allow ESPCs to be used for water conservation measures and for replacement facilities. We have some technical suggestions that we would like to work out with your staff, but could support the intent behind these provisions were they to be included in comprehensive legislation that also addresses the supply and infrastructure issues identified in the National Energy Policy document.

Energy Bank Provisions

Both S. 95 (Kohl) and section 1301 of S. 597 (Bingaman) would create an "energy bank" to help in the funding of federal energy management projects. This is a well-intentioned effort, but I am concerned about the practical applications of this particular language, particularly when we haven't yet fully exploited the opportunities afforded by ESPCs and "super ESPCs."

S. 95 and section 1301 of S. 597 would capitalize the energy bank by collecting 5% of the utility budgets of federal agencies, or roughly $180 billion per year, which we find unworkable. Sharply higher energy prices have already stressed the operations and management (O&M) budgets of many federal agencies in the near term. Requiring agencies to capitalize a new energy bank in the near term, during these times of high energy prices, even if they might produce savings over the long term, would create operational hardships and impair the ability of federal agencies to fulfill their missions.

Moreover, the language of S. 95 and section 1301 of S. 597 is directed at projects with relatively short payback periods of three and seven years. Thus, the Energy Bank projects might "cherry pick" the energy-savings opportunities and actually result in fewer comprehensive energy savings projects.

We need to more fully exploit the opportunities afforded by ESPCs and Super-ESPCs before we experiment with a new tool that could actually result in fewer projects overall. Instead, we are working to make ESPCs more palatable for federal procurement officials who may be intimidated by the prospect of entering into an ESPC on their own. In that regard, we have worked with energy service companies to make "super ESPCs" available.

Super ESPCs, are streamlined indefinite delivery, indefinite quantity contracts. They can be regional or technology-specific. Regional Super ESPCs allow agencies to contract with competitively selected energy service companies in their region for a variety of energy and water efficiency services. Technology-Specific Super ESPCs allow energy service companies to provide certain products (such as geothermal heat pumps or photovoltaic systems) to agencies anywhere in the nation. Both kinds of ESPCs can include maintenance, which is usually done by the energy service company. Delivery orders signed under Super ESPCs specify the products and services that will be provided and estimate the agency's savings and payments to the energy service companies, which assume the up-front capital costs in exchange for a portion of the Federal agency's energy cost savings. Payments are made to the ESCO over the life of the contract, which can be up to 25 years.

As federal agency officials gain experience with ESPCs and Super ESPCs, we should expect to see even greater energy savings than we have seen in the past.

Air Conditioning Standard

Finally, Mr. Chairman, I will comment on Senate Joint Resolution 15 (Boxer), a resolution of disapproval related to energy efficiency standards for residential air conditioners and heat pumps. We oppose this resolution.

The current efficiency standard is 10 SEER (Seasonal Energy Efficiency Ratio) for split air conditioning and heat pump systems and 9.7 SEER for single-package systems. Today, 78% of air conditioning and heat pump sales are at the 10 SEER performance level. Many consumers choose to purchase higher-performing air conditioners and heat pumps, and in some areas of the country this makes very good sense.

However, as a minimum, national standard, to be in effect for <u>all</u> consumers in <u>all</u> areas of the country, the Department of Energy is proposing a 12 SEER performance level that represents a 20% improvement over the current standard.

The purpose of S.J. Res. 15 is to force the Department of Energy to adopt new residential air conditioning and heat pump efficiency standards at the 13 SEER performance level ... a performance level that represents a 30% improvement over the current standard.

It should noted that the incoming Administration reviewed and adopted, without change, efficiency standards covering washing machines, water heaters, and commercial heating and cooling systems. Only in the case of residential air conditioners and heat pumps are we proposing any variation from the prior Administration.

We do not take this action lightly. In the current political atmosphere, the convenient and popular approach would have been to simply accept the 13 SEER standard. But it would have been wrong to do for reasons I will outline.

First of all, the law, specifically section 325 of the Energy Policy and Conservation Act, requires us to determine that new standards will 1) result in significant conservation of energy; 2) are technologically feasible; and 3) are cost effective. The cost effectiveness criteria are specifically outlined in the statute, in the form of six specific tests.

Both the 12 and 13 SEER performance levels would save energy, and both are technologically feasible. You can go out and purchase an 18 SEER model today. You'll pay more, but it is available.

Unfortunately, when confronted with the same cost data that developed in the prior administration, we reached the conclusion that the 13 SEER standard could not meet the cost effectiveness criteria specified in the law. Moreover, our review of the steps taken to by the prior administration as they moved toward the 13 SEER standard in the final weeks of the administration found that DOE failed to seek Department of Justice review for impacts on competition, and that DOE had identified significant manufacturer burdens but did not provide adequate discussion in the Final Rule of how they were considered.

In addition, DOE's analysis, undertaken in the prior administration, found that a 13 SEER performance level for the split air conditioning units (which constitute the majority of the market) would result in higher life cycle costs for 55% of the consumers who bought them. In the case of the low-income consumers who bought them, we found that 64% would face increased life cycle costs. Thus, while some consumers would save money under the 13 SEER standard, and some would save a lot, most consumers would pay more over the long run.

We are also concerned that a 13 SEER performance level would accelerate the consolidation of the industry. Seven large manufacturers (Carrier, Goodman, Rheem, Trane, Lennox, York and Nordyne) already control 97% of the market. DOE calculated that the impact on industry, expressed as the impact on Industry Net Present Value (INPV) through 2020, would be -\$300 million under the 13 SEER standard, and -\$179 million under the 12 SEER standard. This negative INPV would be a force promoting further industry consolidation that would not be good for competition, consumers, or technological innovation.

We also noted that there would be a disparity in impact between low and high cost manufacturers. Indeed, lower cost manufacturers who focus their efforts on marketing minimally compliant systems would be advantaged under the 13 SEER standard.

Finally, we have concerns that a 13 SEER for Heat Pumps could actually increase energy use. Here's how: The installed price of a "13 SEER" split system heat pump is projected to be \$4000 when these regulations take effect, compared to \$2571 for a "13 SEER" split air conditioning system. If that price difference induces only 4% of consumers to choose a combination air conditioning/electric furnace combination over a heat pump, all the energy efficiency advantages of the 13 SEER standards would be lost.

For these reasons, we believe the 12 SEER is the correct minimum national standard that balances energy efficiency, consumer cost, and impact on the manufacturing sector.

With that, Mr. Chairman, let me say that I look forward to working with you and your staff on legislation to promote energy efficiency in the weeks and months ahead. For the moment, I am pleased to answer any questions the Committee may have.

Gas Supply ...

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AGA
American Gas Association

Energy Analysis

Policy Analysis Group
400 N Capitol St NW
Washington DC 20001
www.aga.org

Energy Analysis 2001-03 **July 2, 2001**

LDC SYSTEM OPERATIONS AND SUPPLY PORTFOLIO MANAGEMENT DURING THE 2000 - 2001 WINTER HEATING SEASON

Introduction

The 2000-01 winter heating season (WHS) featured record cold November-December weather conditions, a significant increase in gas commodity prices early and a race by natural gas producers and suppliers to keep up with growing gas demand. To say the market conditions that prevailed, beginning in November 2000, were extraordinary compared to the previous decade is a significant understatement. Many issues came into question as a result, including domestic production capability, the adequacy of volumes in underground storage and pipeline capacity into key gas consuming regions.

National weather patterns only served to fuel gas market concerns. Beginning with the week ending November 11, 2000, national heating degree day (HDD) data revealed nine straight weeks of colder-than-normal, resulting in the coldest November-December period on record. This pattern was broken by the HDD report for the week ending January 13, 2001, which was 25 percent colder than the same week one-year prior but was, in fact, seven percent warmer-than-normal. Of the twelve weeks that rounded out the WHS, at the start of the second week of January, eight were warmer than normal. This in itself likely helped to moderate natural gas prices from the very high levels achieved in December 2000.

Given that backdrop, this Issue Brief describes critical elements of the 2000-01 winter and reports the results of the *AGA LDC Winter Heating Season Performance Survey*, which was conducted under the guidance of the Gas Transportation and Supply Operations (GTSO) Task Force. Data for this report were acquired by surveying AGA member local distribution companies (LDCs) and concentrate on defining peak-day supply practices. This year, responses (whole and part) were received from over 50 LDCs with an aggregate peak-day sendout of 36,169,890 Dekatherms (Dth), acknowledging that the peak-day did not occur on the same calendar day for each company and that each company did not necessarily answer every survey question. A list of companies returning surveys for this year's study is shown in Appendix A. The purpose of the survey is to document gas delivery system operations during the past winter season and to provide insights into managing gas supply and procurement portfolios. **In some cases, this report compares survey results for the 2000-01 winter heating season with those reported in the 1999-00 survey, although the two samples are not identical and the data are not normalized in order to compensate for the sample differences.**

Executive Summary

The 2000-01 WHS was first and foremost characterized by early colder-than-normal temperatures. The foundation for this report comes from survey responses submitted by over 50 AGA member LDCs. These companies had a non-coincident peak-day sendout of 36 million Dth and a median peak-day sendout of 417,758 Dth per company.

Weather

- For nine weeks from November 11, 2000 to January 6, 2001, heating degree days nationally were reported to be colder-than-normal. In fact, they were reported to be as much as 36 percent colder-than-normal and up to 60 percent colder than the previous year. However, during the following 12 weeks, from mid-January until early April, only four were colder-than-normal on a nationwide basis.

- Every census region of the United States was colder-than-normal for the entire WHS and in aggregate accounted for 4.8 percent more HDD than the 30-year norm.

- Ninety-eight percent of survey respondents reported colder-than-normal temperatures in their service territories. Twenty-eight of 48 companies experienced five percent or more HDD than was expected for a normal WHS.

Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services, which often include a diverse set of contractual arrangements, to meet anticipated peak-day and peak-month gas requirements. For instance, prior to the 2000-01 winter many companies were leaning toward shorter-term services to take advantage of declining natural gas commodity prices in the 1990s and to comply with unbundling programs.

- Long-term contractual agreements (one year or more) accounted for 26 percent of 2000-01 LDC peak-day gas purchases, compared to 29 percent in 1999-00. Mid-term arrangements (greater than one-month but less than or equal to a year) accounted for 48 percent of peak-day gas purchases. In addition, the number of LDCs with more than half of their purchases covered by long-term or mid-term agreements were 11 and 21, respectively.

- On average, spot market purchases accounted for 13 percent of LDC peak-day purchases, compared to nine percent in 1999-00.

- Forty-three of 46 respondents indicated that less than half of the gas flowing through their system on a peak-day was being sold to customers by third-party suppliers.

- When asked to describe the distribution of gas supply purchases among suppliers, companies sourced 35 percent of their supplies to producer or producer marketing affiliates, 20 percent to pipeline or pipeline marketing affiliates and 38 percent to independent gas marketers. Other supply aggregators accounted for the rest.

- Firm pipeline transportation accounted for 30 percent of the gas delivered to LDCs on a peak-day, which is seven percent less than was reported in 1999-00. In aggregate, pipeline and on-system storage comprised 36 percent of peak-day gas deliveries compared to 42 percent for the prior winter heating season. Citygate purchases and citygate supplies for transportation customers accounted for another 27 percent of LDC peak-day volumes.

Gas Deliveries and Pricing Issues

Several factors play a role in the market pricing of natural gas and of transportation services, including weather, storage levels, end-use demand,finan cial markets and various operational issues.

Thirteen of 49 companies reported at least some minimal loss of firm supplies at the city-gate at some point during the past WHS. The most common resource utilized to maintain system deliveries was no-notice storage service. In some cases, companies employed on-system propane-air and liquefied natural gas facilities or other on-system underground storage to maintain system integrity.

- The factors most often cited to explain temporary losses of supply included untimely nominations, production cuts on the Gulf Coast, force majeure events, receipt and supply point constraints and other pipeline restrictions.

- For mid-term gas supplies, 55 percent of the volumes were purchased using first-of-the-month pricing, while 24 percent were purchased with fixed pricing and 13 percent daily pricing schedules.

- Twenty-one of the 49 companies responding used financial instruments to hedge at least a portion of their supply purchases. Only six companies hedged more than half of their gas purchases. In addition, some companies used fixed-price contracts to hedge as much as 28 percent of gas volumes delivered on a peak-day. The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

Pipeline Transportation Issues

On the whole, the 2000-01 WHS presented few significant challenges to the pipeline delivery system. However, some disruptions were noted by numerous LDC survey respondents.

- During the recent winter, 21 of 49 LDCs (or 43 percent) indicated that operational flow orders (OFOs) were declared on at least one of the pipelines serving their system. One case in the Pacific Northwest lasted for six weeks, however, most instances were resolved expeditiously.

- Seven respondents indicated that they voluntarily reduced receipts from pipelines in order to help maintain pipeline system integrity.

Gas Storage

High-deliverability and market area storage are key tools for efficiently managing LDC gas supply and transportation portfolios. However, it should be noted that storage practices are no longer dictated by only local utility requirements to serve winter peaking loads. Storage services now support natural gas parking, loaning, balancing and other commercial arbitrage opportunities that take place at market hubs and citygates.

- There are a variety of storage services available to gas customers. LDCs utilize virtually all of the services available. Seventy-three percent of the 48 companies answering the survey section on storage pointed to the use of firm market-area storage at some time during the winter heating season, and 58 percent of the companies indicated that they used no-notice market-area storage services during 2000-01. Firm supply-area storage and no-notice supply area storage were also used by 29 percent and 21 percent of the companies, respectively.

- Ninety-two percent of companies responding indicated that weather-induced demand was the primary factor influencing their use of underground storage, while 73 percent pointed to no-notice requirements. Thirty-three percent referenced additional arbitrage opportunities and 38 percent noted the need to meet "must turn" provisions.

- For the nation as a whole, working gas inventories from January to April 2001 were significantly below the five-year average reported by AGA's American Gas Storage Survey. Only in recent months have strong early season storage injections returned underground storage levels to near the five-year average.

LDC Transportation and Interruptible Customer Issues

Transportation only customers have assumed a higher profile among all customers served by LDCs.

- Sixteen of 48 companies interrupted customers with interruptible services during the 2000-01 WHS. Total interruptions for those companies lasted for a median value of 11 days (not necessarily consecutive).

- Thirteen of 45 companies (or 30 percent) answering the question reported having been aware of operational problems that developed for alternate fuel capable customers during the winter heating season when these capabilities were implemented. For the most part, respondents indicated that the problems were minor.

Weather

The 2000-01 WHS began with what has been described as the coldest November and December on record. During the second-half of the WHS, the weather moderated resulting in a 4.8 percent colder-than-normal winter (October-March) based on national heating degree day totals (normal is defined on the basis of the 30-year period, 1951-1980). It was, in fact, the first winter since 1995-96 that recorded a colder-than-normal heating season. During the initial cold period, heating degree day totals were as much as 36 percent colder-than-normal and over 60 percent colder than the prior year for the same weekly periods.

If examined individually, each of the nine census regions in the US was colder than normal during the 2000-01 winter compared to the previous year when virtually each region was determined to be warmer than normal in aggregate (see Table 1).

TABLE 1

MONTHLY COMPARISON OF NATIONAL HEATING DEGREE DATA
OCTOBER 1999 – MARCH 2001

MONTH	PERCENT CHANGE FROM NORMAL			
	1999 - 2000		2000 - 2001	
October	1.4%	Warmer	10.5%	Warmer
November	19.1	Warmer	15.9	Colder
December	9.6	Warmer	19.6	Colder
January	10.2	Warmer	4.1	Warmer
February	18.3	Warmer	4.3	Warmer
March	19.2	Warmer	7.0	Warmer
TOTAL	13.8%	Warmer	4.8%	Colder

Source U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

AGA survey results agree with national weather data. Ninety-eight percent of survey respondents reported experiencing colder-than-normal weather during this past winter season. Of those, 29 respondents (or 59 percent) experienced weather conditions that were more than five percent colder-than-normal. Eighty-three percent of 48 companies experienced their peak day in December 2000, while 10 percent encountered their peak day in January and six percent in February.

Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services to meet expected peak-day, peak-month and seasonal gas delivery requirements. The 1992 FERC Pipeline Restructuring rule (OrderNo. 636) increased competition in the interstate transportation market but introduced new risks to the process of acquiring natural gas and required pipeline capacity. In today's business environment, gas portfolio managers continually attempt to strike a balance between their needto minimize gas-acquisition risks and their obligation to provide reliable service at the lowest possible cost. Given the reality of significant deviations from normal weather patterns (warm and cold), volatility in commodity prices and regulatory scrutiny of costs to consumers, local gas utility exposure to hindsight for gas supply practices has increased. Also, the recent unbundling of gas sales and transportation services at the retail level in many jurisdictions have further prompted many LDCs to reassess the quantity of gas supplies they must contract for and at what cost. Table 2 shows that local gas utilities continue to be required to make gas supply choices for a majority of their customers and throughput on a peak day.

As shown, 43 out of the 46 survey respondents who completed the question (93 percent) reported that during a peak-day, 50 percent or more of the gas flowing through their system was purchased on behalf of sales customers. That does not mean, however, that significant transportation volumes aren't also flowing. In fact, in addition to planning for the balance of sales and transportation load, when third-party gas suppliers fail to deliver, it is the local utility that fulfills the service needs of natural gas customers. This supplier of last resort (or *next choice)* expectation presents many challenges to gas supply planners.

TABLE 2
LDC-OWNED GAS AS A PERCENT OF TOTAL GAS FLOWING THROUGH THE LOCAL DISTRIBUTION SYSTEM
2000 - 2001 WHS

	RESPONSE COUNT	
	PEAK DAY	PEAK MONTH
0-10%	1	1
11-20%	0	0
21-30%	0	1
31-40%	0	1
41-50%	2	0
51% or more	43	43
TOTAL	46	46

Source 2000-01 AGA LDC Winter Heating Season Performance Survey

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The diverse set of contractual arrangements that LDCs use to procure their gas supplies includes long-term, mid-term, monthly, and daily agreements. A mix of contracts allows the LDC to balance between competing needs, such as the obligation to serve its customers as the supplier of last resort and the need to maximize efficiency while minimizing costs. In many cases, longer-term contracts contribute to baseload obligations, while shorter-term contracts allow companies to respond to market changes. While LDCs have traditionally relied on long-term supply contracts, survey results reflect a transition toward shorter-term and spot contracts to meet peak requirements, which was consistent with demands from consumers, regulators and the market, alike, to pursue least cost options.

TABLE 3
CONTRACTUAL NATURE OF LDC PEAK-DAY GAS PURCHASES

CONTRACT TERMS	PERCENT	
	1999-00 PEAK DAY	2000-01 PEAK DAY
Long term (< 1 year)	29%	26%
Mid term (> 1 month < 1 year)	49	48
Monthly	8	7
Daily Spot	9	14
Supplemental/Other	5	5
TOTAL	100%	100%

Sources: 1999-00 and 2000-01 AGA LDC Winter Heating Season Performance Surveys.

Long-term agreements, defined as one year or longer, accounted for 26 percent of the 2000-01 peak-day gas portfolio compared with 29 percent during the 1999-2000 heating season (see Table 3) and 35 percent the year prior. Not shown in the table is the fact that the proportion of LDCs with more than half of their peak-day gas purchases assigned to long-term contracts decreased from the 1999-00 to the 2000-01 heating season, from 37 percent to 22 percent of survey respondents. In addition, 1999-00 peak-day gas supply purchases made under mid-term contracts (with terms between one month and 12 months) grew to 48 percent of peak-day gas volumes. A greater share of peak-day gas was purchased on the daily spot market this winter than was evident during the preceding heating season. On average, 14 percent of the 2000-01 peak-day gas supplies were bought in the spot market, compared to nine percent of the 1999-00 peak-day volumes. Gas purchased under one-month agreements decreased from eight percent to seven percent of volumes acquired by LDCs.

LDCs utilize a variety of gas supply sources including, but not limited, to firm pipeline capacity and firm pipeline storage in order to meet peak-day requirements. Industry restructuring has increased the options available to LDC shippers, who are now under more pressure to reduce costs while maintaining reliable service. To meet peak-day and peak-month requirements, these shippers now can substitute a variety of services for long-term firm transportation, including pipeline and market-area storage. They also access local production, propane-air/liquefied natural gas supplies and may even execute the buy-back of supplies from dual-fuel capable customers. When asked to describe the distribution of gas supply purchases among suppliers, the mix in aggregate was 35 percent producer or producer marketing affiliate, 20 percent pipeline or pipeline marketing affiliate and 38 percent other gas marketers. Additional supply aggregators accounted for the rest.

Firm pipeline transportation service represented 30 percent of peak-day gas deliveries during the 2000-01 WHS, down from 37 percent reported during the preceding heating season (see Table 4). Only one percent of the peak-day gas deliveries were attributable to interruptible transportation contracts during the 2000-01 WHS. Citygate purchases and citygate supplies for transportation customers accounted for about one-quarter of gas supplies on the peak day.

TABLE 4
LDC PEAK-DAY
GAS SUPPLY SOURCES

CONTRACT SUPPLY SOURCE	PERCENT	
	1999-00 PEAK DAY	2000-01 PEAK DAY
Firm Pipeline Transportation	37%	30%
Interruptible Transportation	1	1
On-System Storage	18	16
Pipeline Storage	24	20
Citygate Purchases	7	10
Citygate Supplies for Trans. Cust.	NA	17
Local Production	1	1
LNG/Propane Air	5	3
Other	7	2
TOTAL	100%	100%

NA = Data not available
Sources. 1999-00 and 2000-01 AGA LDC Winter Heating Season Performance Surveys

Although LDCs have increasingly relied on storage capacity during recent years to meet their peak-day and peak-month requirements, survey results indicate a modest decline in the proportion of storage utilization compared with other peak-day supply arrangements from the 1999-00 winter to the 2000-01 winter. The portions of peak-day volumes allocated to pipeline storage and on-system storage decreased from 42 percent during the 1999-00 WHS to 36 percent during 2000-01. One factor in this decrease could be the fact that the question on gas supply sources was asked differently this year and so some of the gas identified as *citygate supplies for transportation customers* (2000-01) may have been provided from underground storage. At winter heating season's end about 627 billion cubic feet (bcf) of gas still remained in nation-wide working gas inventories, which was below the five-year average for season-ending working gas levels. However, by the end of May the over 325 bcf deficit had been recovered, as early season injections of gas into underground storage proceeded aggressively.

Gas Deliveries and Pricing Issues

The 2000-01 WHS was characterized by an early cold period, which in terms of natural gas prices only exacerbated an already tight supply and demand market. Gas supplies, in general, struggling to rebound from a period of reduced deliverability – due to very low prices to producers and their reluctance to drill and invest – raced to keep up with early season demand. Signaling this tightness in supplies, natural gas prices grew to double digits in the daily cash market and peaked in late December. Hindsight is always clear but analysis of the facts beginning in early 2000 point to the difficulty in predicting the course of events that unfolded.

For the first quarter of 2000, natural gas prices, on an average national basis, remained within the bounds of average pricing for the past decade (less than $2.50 per million Btu). As average prices crept toward $4.00 and more, supply planners waited to see if the higher prices would reverse themselves and fall during the summer as is often the case. There is no real-time measure of natural gas production capability available to supply planners, so it is difficult to predict with accuracy the impact of changes in domestic production on near-term gas supply and market prices. In fact, the trend of higher prices at the wellhead was not reversed until after the first weeks of January 2001 when the combination of warmer-than-normal weather, demand destruction due to higher prices and growing domestic production capability in response to higher wellhead prices began to take hold.

Such market factors impact LDCs and other gas suppliers making it difficult for all players to plan. Twenty-seven percent of survey respondents reported some level of non-delivery gas supplies during the 2000-01 WHS, while 24 percent reported losses of spot gas supplies. Most of those companies that did experience losses of either firm or spot supplies used no-notice storage service to maintain system deliveries. Three of the 30 respondents that experienced supply losses also relied on LNG/propane air facilities or even no-notice transportation to maintain system integrity.

All 49-survey respondents (answering the question) reported the telephone as the primary means by which suppliers notified them of problems with their firm supplies. Twenty-six of those also noted the FAX machine as a widely used mode of communication, followed by e-mail (18 companies) and proprietary EBB interfaces (11 companies). Pipeline allocation problems and upstream failures to deliver gas were cited as factors leading to firm and spot supply cuts. Other factors, which contributed to both firm and spot supply losses, included pipeline maintenance, force majeure events and receipt and supply point constraints.

Winter Heating Season Pricing

Many factors play a role in the market pricing of the gas commodity and of transportation services, including weather, storage levels, end-use demand, pipeline capacity, operational issues, and functioning financial markets. The industry fundamentals that created a basis for the gas acquisition price increases of 2000 (noted in Table 5) are well chronicled. Undeniably, actions taken in the financial markets -- but primarily the critical balance between gas supply availability and short-term demand -- drove winter heating season prices up, then caused them to retreat beginning in January 2001.

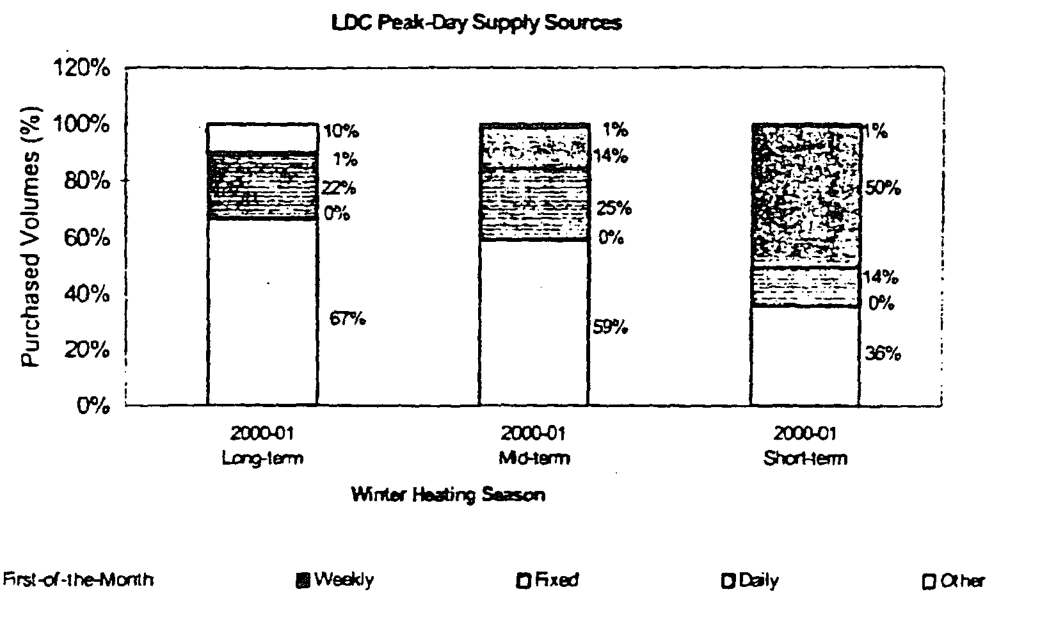
TABLE 5
TRENDS IN NATURAL GAS SPOT PRICES
DECEMBER 1999 – MARCH 2001

PRICING POINT	DEC '99	MAR '00	JUNE '00	SEPT '00	NOV '00	DEC '00	JAN '01	FEB '01	MAR '01
DELIVERED TO PIPELINE ($ per MMBtu)									
Texas	2.05	2.49	4.23	4.49	4.40	5.93	9.78	6.16	4.91
Louisiana	2.09	2.56	4.33	4.56	4.44	5.95	9.86	6.16	4.95
Oklahoma/Kansas	2.05	2.48	4.20	4.49	4.40	5.89	9.88	6.19	4.97
Rocky Mountains	2.06	2.33	3.57	3.37	4.33	6.04	8.69	6.43	4.81
Henry Hub	2.14	2.61	4.37	4.62	4.50	6.02	9.91	6.22	5.03
Waha	2.04	2.48	4.17	4.59	4.50	6.16	9.77	6.41	5.03
CITIGATE ($ per MMBtu)									
California	2.38	2.55	4.27	5.98	5.16	15.34	14.78	12.13	11.18
West Great Lakes	2.25	2.69	4.48	4.80	4.62	6.22	10.67	6.87	5.35
New York/New Jersey	2.74	2.90	4.67	4.93	4.99	6.92	13.72	8.42	5.53
New England	2.70	3.01	4.70	4.95	5.06	7.07	12.31	7.98	5.59

NA = Data not available
Source: *Inside FERC's Gas Market Report*

Many LDCs continue to price gas based on numerous indexes during the winter heating season. In fact some LDCs refer to their pricing strategies as a *basket of indices*. LDCs that purchased mid-term supplies during the 2000-01 winter relied heavily on first-of-the-month pricing (55 percent of their volumes) to value gas purchases. Twenty-four percent of the volumes were purchased using a fixed multi-month price schedule, while 13 percent of mid-term volumes were purchased in the daily market. Figure 1 shows how the proportions of mid-term gas supplies were purchased with the various pricing mechanisms. On a company basis (regardless of volumes), 17 of 49 companies answering the question purchased 50 percent or more of their short-term (less than one month) supplies during the 2000-01 winter heating season using daily spot prices. Fourteen companies also used first-of-the-month indices for at least 50 percent of their spot purchases.

FIGURE 1



It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior and anticipated experiences. Even state regulatory approved pricing mechanisms can appear favorable one year and less attractive another. Flexibility and constructive review of policies, rather than second-guessing, can effect positive impacts on bringing natural gas and services to customers at the lowest possible cost.

Hedging Mechanisms

Market developments during the 1990s have expanded gas supply options, transportation capacity trading and the use of financial instruments. Today, industry players use futures contracts and other tools to offset the risk of commodity price movements. These financial instruments, which to some extent include fixed-price gas purchase contracts, futures, and options, allow gas supply portfolio managers to hedge or lock in a portion of the gas cost component of gas supplies. This is achieved particularly when the level of risk required and the rewards or benefits of managing the risk are properly balanced by the company, consumers and regulatory bodies.

Twenty-one of the 49 LDCs answering the question in the survey said they used financial instruments and fixed-price contracts to hedge a portion of their gas supply purchases during the 2000-2001 winter. Of those responding affirmatively, 14 companies said they hedged using fixed-price contracts, seven reported having hedged using futures and six used options. A smaller number used swaps. Five of the 46 companies reporting used weather derivatives as a hedging tool, while 41 companies did not. In addition, five of 47 companies reported that state regulators had specifically disallowed the use of certain financial tools.

When asked how far forward they normally hedged, of the companies that did use hedging and fixed-price instruments, 12 used a seasonal approach, eight annual, three monthly and four a combination of seasonal, annual and longer than one year terms. Additionally, the use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by that third-party rather than the LDC or customer and may not have been calculated into in the LDC hedging response. Of those Companies that were able to identify that purchases received from marketers had already been hedged, most pointed to 10 to 25 percent of those purchases as being hedged or more than 50 percent of those purchases having been hedged by financial instruments or fixed prices.

Based on experiences from the 2000-01 WHS, companies were asked to assess whether they planned to use hedging tools to a greater extent for the coming 2001-02 winter or less. Twenty-eight of 47 companies (60 percent) said they expected to hedge more of their gas volumes for the coming winter heating season compared to 2000-01, while only four indicated less. Eleven stated that they did not use financial instruments directly, and three expected to utilize the existing tools to the same extent as in 2000-01.

Pipeline Transportation Issues

The 2000-01 WHS was characterized more by public awareness of increasing gas commodity costs rather than by any failure of the pipeline delivery system. Only 27 percent of survey respondents experienced non-delivery of primary firm gas supplies. Twenty-four percent of the companies experienced a loss of some spot supplies. Force majeure events, minor cuts due to supplier pool imbalances and pipeline constraints created by over nominations were some of the reasons cited for such curtailments.

That is not to say that every system ran without incident or did not require participant cooperation. Forty-three percent of LDCs stated that OFOs were declared on one or more of the pipeline systems that they used to transport their gas supplies. Seven companies reported even having voluntarily reduced their pipeline receipts at some time during the winter heating season in order to maintain pipeline system integrity. In most of those situations disruptions were minor and of short duration. However, one notable exception was in the Pacific Northwest, where OFOs were in effect from November 18 until January 2 on the NorthwestPipeline system.

Gas Storage

As noted earlier, LDCs are concerned with managing gas supply and transportation portfolios efficiently to reduce costs. High-deliverability and market area storage can help LDCs to meet such goals. The use of such storage facilities helps LDCs to meet short-term swing opportunities as well as to satisfy peaking needs. LDCs now use high-deliverability storage facilities, such as salt-dome facilities, for short-term strategic marketing objectives and arbitrage opportunities. Table 6 shows storage levels as estimated by the *American Gas Storage Survey* as a five-year average (1996-00) compared to year 2001 estimates for the months January-April. For the nation as a whole, working gas inventories during the January-April 2001 period were below the five-year average reported by AGA's *American Gas Storage Survey*. Two main factors account for the reduced inventory: strong underground storage withdrawals in response to early season cold weather and the fact that net injections during 2000 resulted in lower than average storage volumes at the beginning of the winter heating season. That deficit was aggressively eliminated beginning with strong net injections in April and May 2001.

TABLE 6
AMERICAN GAS STORAGE SURVEY
WORKING GAS IN STORAGE

	Five Year Average 1996 – 00 (Bcf)					2001			
	Total	**Prod**	**East**	**West**		**Total**	**Prod**	**East**	**West**
Jan	2162	586	1250	326	Jan05	1562	350	935	277
	2025	551	1162	312		1459	323	872	264
	1862	506	1059	297		1369	312	816	241
	1708	469	959	280		1241	296	723	222
Feb	1552	428	858	266	Feb02	1136	277	657	202
	1432	402	772	258		1041	267	592	182
	1319	379	694	246		960	257	537	166
	1237	367	631	239		859	242	456	161
Mar	1180	363	590	227	Mar02	786	236	402	148
	1100	351	534	215		711	225	341	145
	1019	334	475	210		688	228	310	150
	970	326	430	214		676	223	297	156
	956	332	410	214		627	210	253	164
Apr	974	341	423	210	Apr06	641	218	252	171
	968	344	413	211		705	238	295	172
	988	349	425	214		748	252	315	181
	1032	359	452	221		850	286	372	192

Source: American Gas Association

Of the 48 companies that reported utilizing underground storage during the 2000-01 winter heating season, the majority (73 percent) depended on market area firm storage to meet a portion of their requirements. Of those companies using market area storage specifically, 58 percent also identified a form of no-notice service, and eight percent employed interruptible storage. Weather-induced demand compelled most of the respondents to utilize storage services. However, respondents also singled out no-notice requirements and arbitrage opportunities as reasons to maintain storage services within their gas supply portfolio.

Most companies (77 percent) indicated that storage refill decisions during the 2000 injection season were made on the basis of operational issues, while 19 percent pointed to market price considerations. (One company gave them both equal weight.) Most gas purchases for storage injections during 2000 were made based on first-of-the-month indices. In fact, 34 of 49 companies indicated that more than 50 percent of the supplies purchased for storage injections were so priced. Fixed schedules accounted for about 11 percent of the volumes of gas put into storage, while daily prices applied to 22 percent.

LDC Transportation and Interruptible Customer Issues

As is always the case, companies indicated some non-delivery of gas supplies during the 2000-01 WHS. In most cases, the LDC elected to keep transportation customers whole by utilizing, among other things, no-notice storage, no-notice transportation, firm storage and firm transportation services. For the most part, interruptions were brief and involved small volumes. However, the data point to the need of LDCs to ensure that unbundling programs are designed in a way that promotes reliability. If a small-volume customer arranges for third-party transportation supplies and those supplies are not delivered to the citygate, LDCs often are operationally unable to prevent the customer from taking gas it is not entitled to. Transportation programs need to contain tariff provisions that provide sufficient incentives and penalties for suppliers to meet their contractual obligations under all scenarios and to ensure that end-users understand and adhere to their obligations during times of supply and market fluctuations.

Eighteen companies indicated that during the course of the 2000-01 WHS dual-fuel capable customers sold gas back to the market. Thirteen local gas utilities were aware of instances where dual-fuel customers had difficulties operating the alternate fuel supply or equipment. For the most part, respondents indicated these problems were minor. Seventeen LDC survey respondents reported that interruptible customers continued to take gas after being notified that their supply was to be temporarily interrupted.

Appendix A

2000-01 Winter Heating Season Survey Participants

Alagasco, An Energen Company

Baltimore Gas and Electric
Berkshire Gas Company

Chesapeake Utilities
Clearwater Gas System
Colorado Springs Utilities
Columbia Gas of Kentucky
Columbia Gas of Maryland, Inc.
Columbia Gas of Ohio, Inc.
Columbia Gas of Pennsylvania, Inc.
Columbia Gas of Virginia, Inc.
Commonwealth Gas Co.
Consumers Energy

Easton Utilities
Equitable Gas Co.

Kokomo Gas and Fuel Co.

Madison Gas & Electric Company
Memphis Light Gas & Water
Metropolitan Utilities District
MichCon
MidAmerican Energy
Mobile Gas Service Corp.
Montana Power Co.

National Fuel Gas Distribution Co.
New Jersey Natural Gas
Niagara Mohawk
Nicor
Northern Indiana Public Service Co.
Northwest Natural

Okaloosa Gas District

Peoples Energy - North Shore Gas
Peoples Energy - PGL&C
PG Energy
Philadelphia Gas Works
Piedmont Natural Gas Co.

Questar Gas Co.

Reliant Energy Entex
Roanoke Gas Co.

SEMCO Energy Gas Company
Southern Connecticut Gas Company
Southern Indiana Gas & Electric
Southern Union
Southwestern Energy Company

TU Electric, Lone Star Gas

Union Gas Limited

Vectren Energy - Indiana Gas
Vermont Gas Systems, Inc.

Washington Gas
Wisconsin Public Service Corp.

Xcel Energy/Northern States Power
Xcel Energy/Public Service Co. of CO

Yankee Gas Services Co.

EERE Program Pictures

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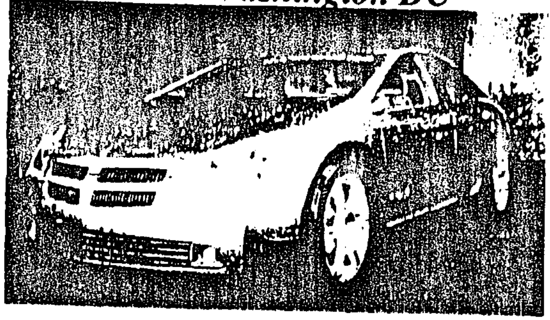
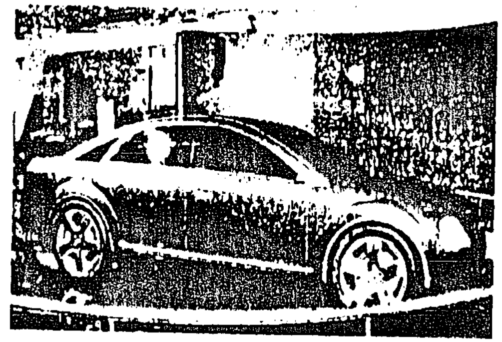
2000 Washington DC



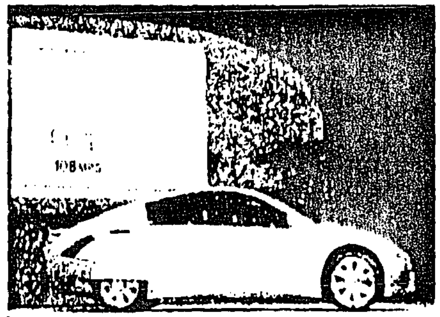
Dodge ESX3
- Body system weighs 46% less*
- Efficient diesel engine, motor and battery achieve 72 mpg*
- Incremental cost penalty halved

2000 Detroit Auto Show



Ford Prodigy
- Better than 70 mpg
- Lightweight materials reduce vehicle weight 30% *
- Integrated starter/alternator *
- 33% reduction in aerodynamic drag
- Advanced diesel engine with 35% efficiency improvement *
- High power battery *

2000 Detroit Auto Show



<u>GM Precept</u>

- Vehicle mass reduced 45% *
- Eliminates need for power steering
- Lowest drag coefficient ever recorded for a 5-p sedan
- Fuel cell version projected to get 108 mpg *

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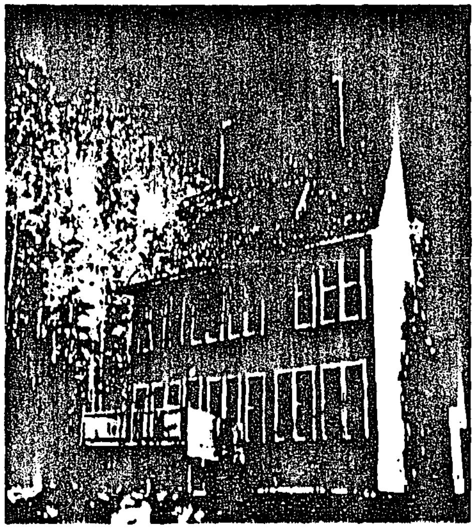

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energy

EPA DOE

DOE024-0628

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Statement of Francis Blake
Deputy Secretary
before the Subcommittee on
Energy and Air Quality,
House Committee on Energy and Commerce
National Electricity Policy:
Federal Government Perspectives
September 20, 2001

Mr. Chairman and Members of the Subcommittee, I welcome the opportunity to testify before you today on national electricity legislation.

Last Week's Terrorist Attack

Before I address the subject of this hearing, I would like to briefly address the energy issues arising out of the vicious and cowardly attack on our country last week.

The terrorist attack on our country had a significant impact on the energy infrastructure in lower Manhattan. The fire and building collapses destroyed two substations located under the World Trade Center as well as power transformers, circuit breakers, underground cable and other distribution equipment. Multiple transmission lines were damaged, resulting in the outage of a third substation. Con Edison is restoring limited temporary service by deploying mobile generators and reconfiguring portions of the effected distribution system. New power lines are being installed above ground to replace damaged underground cable. Normal electricity service in areas where there is limited physical damage is being restored, but restoration to areas where there is significant damage will take much longer. There also has been a disruption to natural gas service in lower Manhattan. The attack on the Pentagon had no impact on the energy infrastructure in the Washington, D.C. area.

Last week's attack raises issues relating to the security of our energy infrastructure. Outside of lower Manhattan, our energy infrastructure was not affected, and there were no specific threats to oil refineries, oil and gas pipelines, electric transmission lines, and generation facilities, including nuclear power plants.

Notwithstanding, the security of our energy infrastructure was upgraded in the wake of the attack. Commercial nuclear power plants were placed on their highest alert status, the North American Electric Reliability Council, an industry organization responsible for maintaining bulk power system reliability, recommended that transmission operators implement heightened security measures, pipeline owners were put on high alert after the attacks, and security at oil refineries was upgraded.

As you know, there were isolated reports of gasoline price gouging in the wake of the attack last week. In response, the Secretary of Energy determined there was no supply disruption to justify reported prices and issued a public statement that these high prices were unjustified. The Federal Trade Commission also threatened to take enforcement action. Gasoline price spikes receded in wake of these actions.

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responsibility over wholesale electricity markets and the transmission of electricity in interstate commerce.

The Administration believes that electricity legislation should focus on core Federal issues that are beyond State authority.

Regulation of Interstate Commerce

Electricity markets are increasingly regional in nature. Under the Constitution, States have no authority to regulate interstate commerce and regulation of interstate commerce is a Federal responsibility. The California experience shows that actions taken by one State can have regional consequences.

Transmission

Assuring that our transmission system can deliver reliable electricity supplies is a core Federal issue. As the National Energy Policy noted, investment in new transmission capacity has failed to keep pace with growth in demand and with changes in the industry's structure. Since 1989, electricity sales have increased by 2.1 percent per year, yet transmission capacity has increased by only 0.8 percent per year. There is widespread recognition that there is a need to expand the transmission system, remove bottlenecks, and provide for open access. Since the transmission system is both interstate and international, regulation of the grid is a Federal responsibility.

There are various reasons why transmission constraints exist. In some cases, the problem is a lack of economic incentive. The national energy policy proposes a solution to that problem: encouraging the Federal Energy Regulatory Commission (FERC) to develop incentive rates to promote transmission expansion. FERC has great flexibility under current law to set transmission rates at a level to attract investment. Recently, FERC has shown flexibility in considering nontraditional transmission rates. For those reasons, it does not appear legislation is needed to address transmission pricing.

In other cases, the problem is the siting process itself. Under current law, transmission siting is an exclusively State function. That law was written 66 years ago, at a time when power plants were located right next to customers, and decades before transmission lines interconnected States and regions. Congress did not provide for transmission siting by the Federal government because it did not foresee the transmission system would develop into not only an interstate but also an international grid.

Much has changed since 1935. The transmission grid is the interstate highway system for electricity. It should not be a system of local toll roads.

Electricity legislation can remove transmission bottlenecks by providing for siting by the Federal government of transmission facilities used for interstate transmission. The Administration believes legislation should preserve State transmission siting authority, but should provide for Federal siting of transmission facilities that are in the national interest, based on effects on reliability, interstate commerce in electricity, and on competition in wholesale electricity markets. We believe Federal siting decisions should rely in large part on recommendations made by regional siting boards.

We also believe that Federal electricity legislation should grant FERC authority to require State and municipal utilities and rural electric cooperatives to provide open access to their transmission systems, in the same manner as jurisdictional transmitting utilities. This is a step towards establishing one set of rules to govern the transmission grid.

Reliability

Ensuring the reliability of the interstate transmission system is also a Federal responsibility. Since the 1960s, the reliability of our transmission system has been based on voluntary compliance with

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unenforceable reliability standards. That is no longer tenable, and Federal legislation is needed to provide for enforceable standards developed by a self-regulating organization subject to FERC oversight.

Market Power

The Administration believes that FERC needs to be able to mitigate market power. However, the debate about market power often starts with a misunderstanding about FERC authority under current law. Under the Federal Power Act, FERC is responsible for ensuring that rates charged by public utilities are just and reasonable. As a general matter, the ability to set rates is the ability to prevent the exercise of market power. An exercise of market power generally entails charging rates that are higher than those produced in a truly competitive market. For that reason, FERC can prevent the exercise of market power through its authority over wholesale rates and by ordering refunds of unjust and unreasonable rates.

In our view, a discussion of market power issues must start with an understanding of FERC authority under existing law and a determination of whether existing FERC authority to address market power is inadequate.

Legislation can strengthen FERC authority to address market power. For example, the Administration believes legislation should amend the refund provisions of the Federal Power Act and provide that refunds are effective on the date of complaint, not 60 days later. The Administration believes there is a need to increase the penalties for criminal violations of the Federal Power Act and expand the scope of the civil penalty provisions to include any violation of the Federal Power Act, not just the provisions added by the Energy Policy Act of 1992.

The Administration believes that FERC should retain its authority to approve mergers and asset dispositions, given its expertise on the electricity industry. We also believe it is appropriate to clarify FERC authority to approve holding company mergers and mergers and asset dispositions involving generation facilities.

Electricity Supply

The lack of uniform interconnection standards appears to have contributed to the difficulty in developing independent power plants in some regions of the country. Federal legislation can help assure adequate electricity supplies, by providing for uniform interconnection standards and reforming FERC authority to issue interconnection orders.

Consumer Protection

Electricity markets are regional in nature, and are no longer confined neatly within individual States. For that reason, there is a need for electricity legislation that protects consumers against "slamming" and "cramming," strengthens the bargaining power of consumers through aggregation, protects consumer privacy, and ensures that consumers have the information to make informed decisions to meet their needs.

Federal Electric Utilities

Another core Federal issue is defining the role of Federal electric utilities like the Tennessee Valley Authority (TVA) and Bonneville Power Administration in competitive electricity markets. Obviously, States have no authority over Federal electric utilities. Legislation is needed to provide open access to transmission systems operated by the Federal electric utilities and ensure that one set of rules governs the entire interstate transmission system. There is a need for other specific TVA and Bonneville reforms. I assure the Subcommittee that the Administration intends to work closely with the Congressional delegations from these regions on these reforms.

Reform of Federal Electricity Laws

There is a need to reform Federal electricity laws, such as the Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act of 1978 (PURPA). With respect to PUHCA, each of the past four presidents has supported PUHCA repeal. PUHCA repeal is an idea whose time came a long time ago. There is also a need to repeal the PURPA mandatory purchase obligation prospectively.

Jurisdiction

Federal legislation should also clarify Federal and State jurisdiction. One jurisdictional issue is State authority to charge public purpose fees. The Administration believes that States are in the best position to develop public purpose programs to suit their needs. Some States may prefer to develop strong low-income assistance, while others focus on rural assistance, while still others concentrate on conservation. States have different needs, and need the flexibility to craft programs to suit those needs. These programs can be funded through the distribution charges - an area where States have exclusive jurisdiction - or charges on retail sales of electricity.

Electricity legislation can clarify the authority of States to impose fees to fund public purpose programs that meet their needs and avoid bypass of State fees. We believe this is a better approach than imposing a Federal tax to fund a Public Benefits Fund. One concern relating to a Public Benefits Fund that has not received much attention is equities in allocating funds. There is no assurance that fees raised in one State to finance a Public Benefits Fund will not be spent in other States.

Energy Efficiency and Renewable Energy

A stable power supply should consist of a clean and diverse portfolio of domestic energy supplies - including renewable and alternative supplies - that are available right here in the United States. The National Energy Policy includes several recommendations on ways that new and emerging technologies can help us provide for increased generation of electricity while protecting the environment, as well as on ways to increase use of renewable and alternative energy supplies. These recommendations should be considered as electricity legislation is developed.

By no means is this intended to be an exclusive list and there are other issues that may be appropriate to address in Federal electricity legislation.

Conclusion

We have a rare opportunity to learn a lesson from the California experience and act to prevent a future electricity crisis. Congress normally passes energy legislation in the wake of a crisis, and it is rare for Congress to act to prevent an energy crisis.

Mr. Chairman, Congress has been slowly reforming Federal electricity laws for over twenty years. This process began with the Public Utility Regulatory Policies Act of 1978, which the encouraged the development of independent power producers. This process continued with enactment of the Energy Policy Act of 1992, which provided greater access to the transmission system and further encouraged the development of independent power producers. The time has come for Congress to take another step, a bigger step, one that can make electricity markets more competitive and result in lower electricity prices, and ample and reliable electricity suppliers.

The Administration looks forward to working closely with the Committee to develop comprehensive electricity legislation.

I appreciate the opportunity to testify before you today.

Date: September 20, 2001

Dingaman.gcd

207

QUESTION FROM SENATOR WYDEN

Promotion of Development of Geothermal and Other Renewables on Federal Lands

Q2. I would like you to provide your views on the effort to develop a geothermal energy project on Federal lands in the Glass Mountain area near the Southern Oregon border. The entire process has literally dragged on for decades. It involved getting the Bonneville Power Administration to make a commitment to buy energy in the project and the Forest Service and BLM were also involved in a whole series of environmental reviews. Getting each of these agencies on board has involved years of reviews and delays on decisions about the project. Last year, then Energy Secretary Richardson called it "an important test of the future viability of geothermal energy in the West." If that's the case, then I think you would have to give a grade of "needs improvement" on that test. What can this Administration do to promote the development of geothermal and other renewable energy sources on Federal land in an environmentally responsible way?

A2. The Department of Energy supports increasing the use of geothermal energy in the West and has specifically gone on record in support of both the Fourmile Hill and the Telephone Flat projects in the Medicine Lake Highlands near Glass Mountain. While the Department was a participating Federal agency in the process of preparing an Environmental Impact Statements for both of those projects, we did not have the authority or responsibility for issuing either Record of Decision. That responsibility lay jointly with the U.S. Bureau of Land Management and the U.S. Forest Service. Both projects underwent considerable scrutiny during the review process, which was instrumental in helping those agencies formulate mitigation plans to minimize potential impacts from the projects. In the case of the Telephone Flat project, the impacts were judged to be unacceptable, even with mitigation, and the project was denied. However, the Fourmile Hill project was authorized to proceed under rather stringent conditions.

In May of this year, the National Energy Policy Development Group issued its recommendations for reliable, affordable, and environmentally sound energy for

America's future. An entire chapter was devoted to increasing use of renewable and alternative energy, including geothermal energy. It included the following two recommendations relevant to leasing of Federal land for geothermal development:

- The NEPD Group recommends that the President direct the Secretaries of the Interior and Energy to re-evaluate access limitations to Federal lands in order to increase renewable energy production, such as biomass, wind, geothermal, and solar.

- The NEPD Group recommends that the President direct the Secretary of the Interior to determine ways to reduce the delays in geothermal lease processing as part of the permitting review process.

The Department of Energy is working closely with the Departments of the Interior and Agriculture to implement these recommendations and help increase the use of renewable energy, including geothermal energy, on public lands.

Assistant Secretary's Initials:
Office Director's Initials:
DAS Initials:
PSO Initials:
Date: August 31, 2001

Preparation Lead: EERE
Preparation Team: Ray LaSala
Reviewed by: Patrick Booher

Date Question Received: August 29,2001

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Strategic Program Review Workbook
BIBLIOGRAPHY of EXTERNAL REVIEWS

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Office of Technology Assessment, "Application of Solar Technology to Today's Energy Needs—Vol. 1," June 1978.

Office of Technology Assessment, "Industrial Energy Efficiency," August 1993.

205

Hutto, Chase

From: Doug Faulkner
Sent: Wednesday, July 18, 2001 11:29 AM
To: Glotfelty, Jimmy; Reed, Craig; Hutto, Chase
Subject: Dept. of Interior meeting: proposed Renewable Energy Summit

fyi. chase, remember that we came up with this summit idea a while ago...

---------------------- Forwarded by Doug Faulkner/EE/DOE on 07/18/2001 11:27 AM ----------------------

Robert Dixon
07/18/2001 08:19 AM

To: David Garman/EE/DOE@DOE
cc: Doug Faulkner/EE/DOE@DOE, William Parks/EE/DOE@DOE, Peter Goldman/EE/DOE@DOE, Allan Jelacic/EE/DOE@DOE

Subject: Dept. of Interior meeting: proposed Renewable Energy Summit

Dave:

Bob

23235

DOE024-0641

209

Hutto, Chase

From: James Lucier [James.Lucier@att.net]
Sent: Tuesday, August 07, 2001 11:27 AM
To: RC-MEMBERS@HOME.EASE.LSOFT.COM%internet
Subject: Peter Huber: Technology Investment Implications of National Energy Policy

Bush Energy.pdf

23236

DOE024-0642

Hutto, Chase

5/5

From: Adrianne Moss
Sent: Thursday, May 24, 2001 5:23 PM
To: Hutto, Chase; Whatley, Michael; Disch, Ellis; Kelliher, Joseph; Kolevar, Kevin; Faulkner, Doug
Cc: Telson, Michael; Dawson, Deborah A; Henderson, Lynwood
Subject: Request from Appropriations Staff for National Energy Policy Briefing

Who can help us to set this up?

23239

DOE024-0645

Hutto, Chase

From: Whatley, Michael
Sent: Thursday, May 24, 2001 8:00 PM
To: Burnison, Scott; Hutto, Chase
Subject: RE: NEP briefing for HEWD

I will call them and arrange a briefing.

Thanks.

-----Original Message-----
From: Scott Burnison
Sent: Thursday, May 24, 2001 4:55 PM
To: CN=Michael Whatley/O=HQ-EXCH/C=US@HQDOE@CRDOE%HQ-NOTES; CN=Chase Hutto/O=HQ-EXCH/C=US@HQDOE@CRDOE%HQ-NOTES
Cc: Moss, Adrianne
Subject: NEP briefing for HEWD

Mike and Chase,

Kevin Cook from House Energy and Water Development subcommittee called me and asked if he and Jeanne Wilson could get a briefing on how the National Energy Policy as proposed by the Vice President's Development Group might impact the Energy & Water bill. I am not sure who the most knowledgeable person is to take the lead in such a meeting. How would you like me to handle the request?

Scott

23240

DOE024-0646

Hutto, Chase

From:	Scott Burnison
Sent:	Thursday, May 24, 2001 4:55 PM
To:	CN=Michael Whatley/O=HQ-EXCH/C=US@HQDOE@CRDOE%HQ-NOTES; CN=Chase Hutto/O=HQ-EXCH/C=US@HQDOE@CRDOE%HQ-NOTES
Cc:	Moss, Adrianne
Subject:	NEP briefing for HEWD

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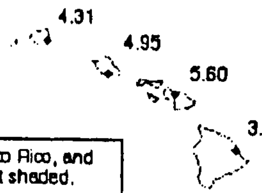
Scott

23241

DOE024-0647

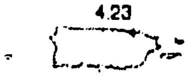
Alaska

Hawaii



Hawaii, Puerto Rico, and Guam are not shaded.

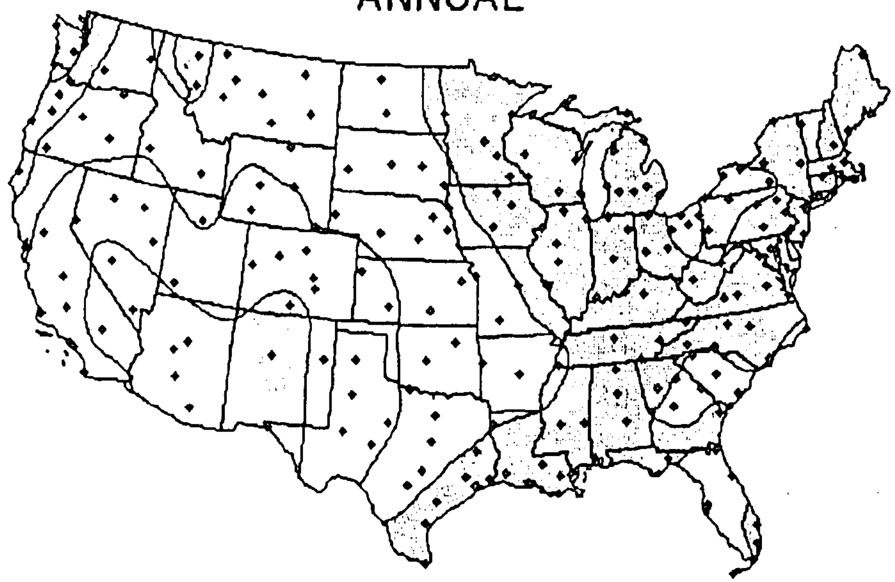
San Juan, PR



Guam, PI

Average Daily Solar Radiation Per Month

ANNUAL



North-South Axis Tracking Concentrator Tilted at Latitude

Collector Orientation

One-axis tracking parabolic trough with a horizontal north-south axis and tilted from the horizontal at an angle equal to the site's latitude

This map shows the general trends in the amount of solar radiation received in the United States and its territories. It is a spatial interpolation of solar radiation values derived from the 1961-1990 National Solar Radiation Data Base (NSRDB). The dots on the map represent the 239 sites of the NSRDB.

Maps of average values are produced by averaging all 30 years of data for each site. Maps of maximum and minimum values are composites of specific months and years for which each site achieved its maximum or minimum amounts of solar radiation.

Though useful for identifying general trends, this map should be used with caution for site-specific resource evaluations because variations in solar radiation not reflected in the maps can exist, introducing uncertainty into resource estimates.

Maps are not drawn to scale.

NREL

National Renewable Energy Laboratory
Resource Assessment Program

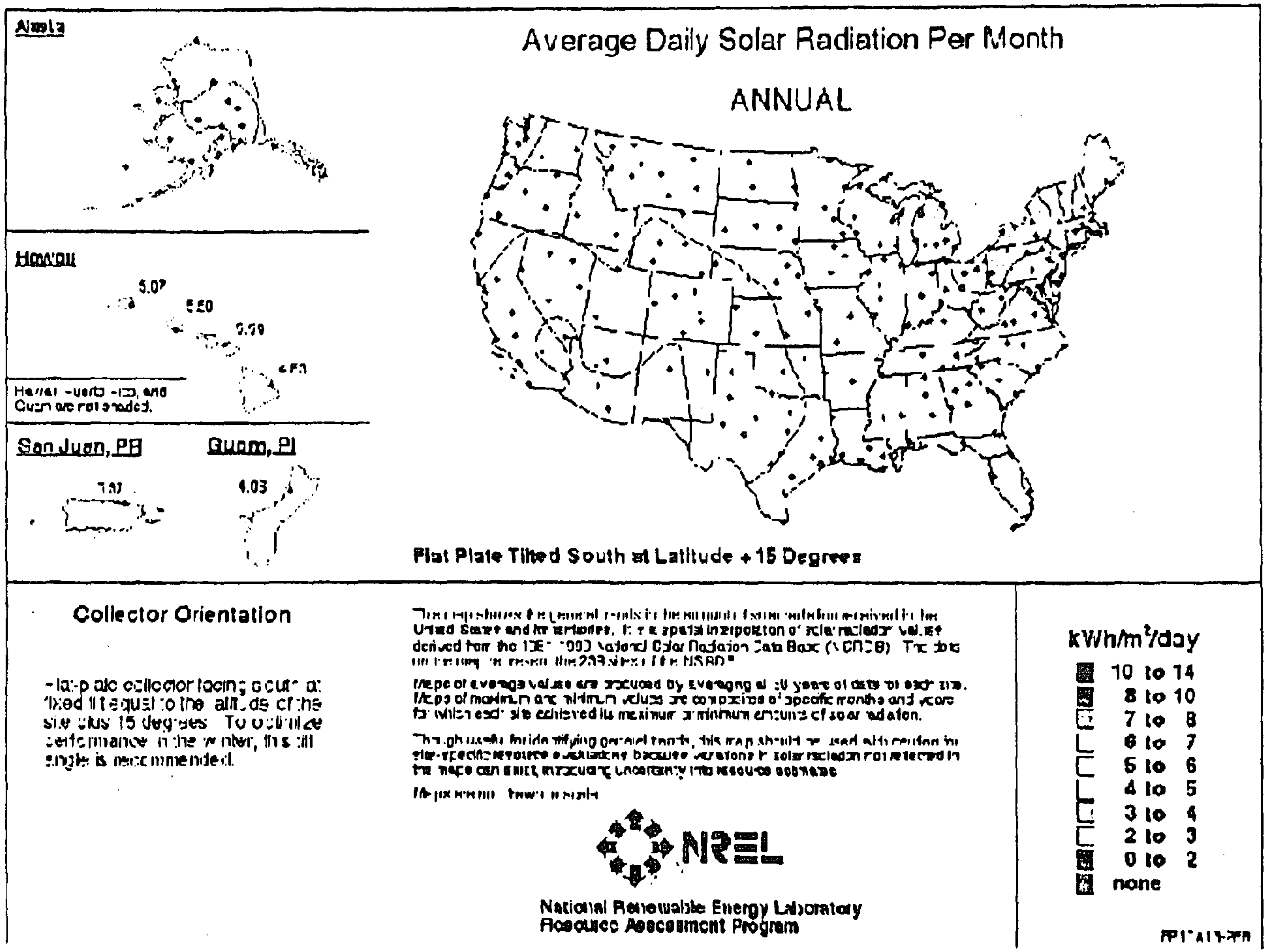
kWh/m²/day

▪	10 to 14
▪	8 to 10
☐	7 to 8
☐	6 to 7
☐	5 to 6
☐	4 to 5
☐	3 to 4
☐	2 to 3
▪	0 to 2
▪	none

C1XLA13-52

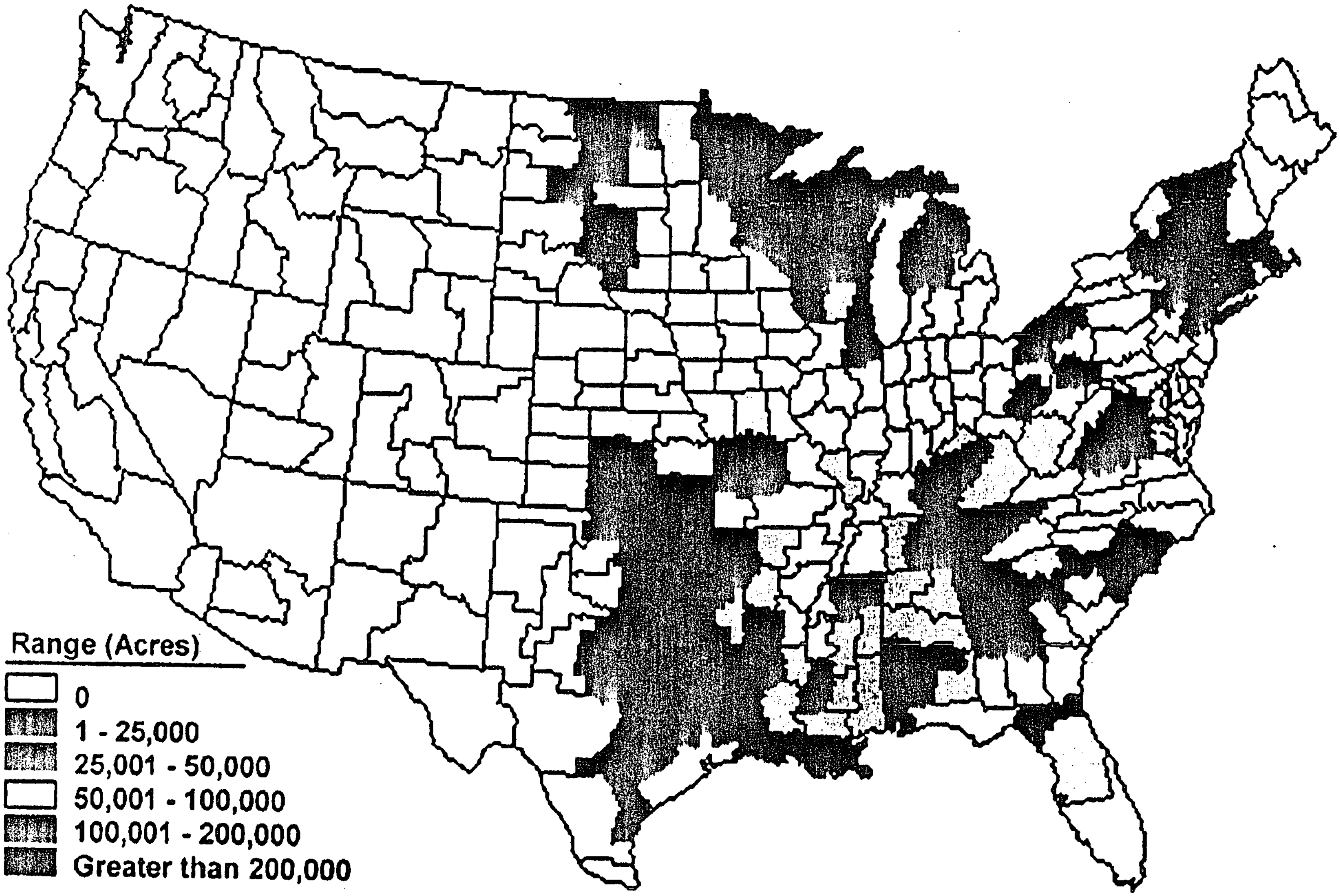
DOE024-0648

23242

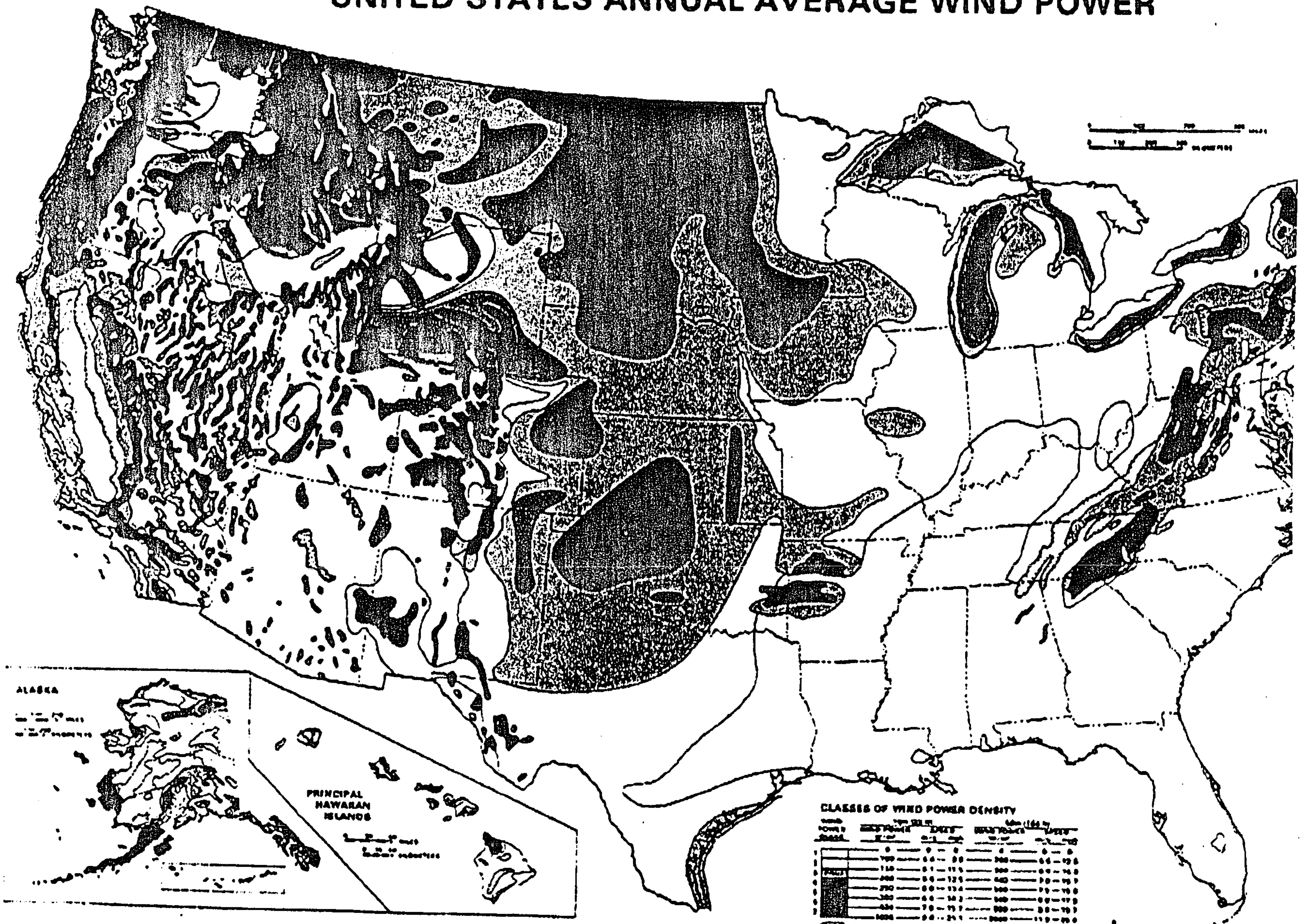


DOE024-0649

23243


Range (Acres)
0
1 - 25,000
25,001 - 50,000
50,001 - 100,000
100,001 - 200,000
Greater than 200,000

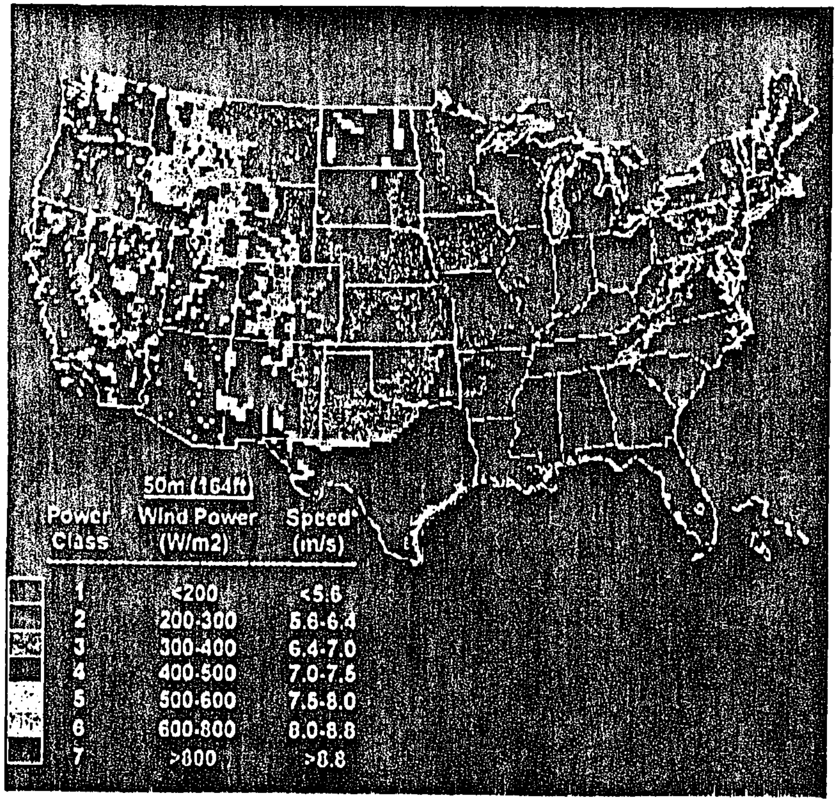
UNITED STATES ANNUAL AVERAGE WIND POWER



Wind Resource

DOE024-0651

23245



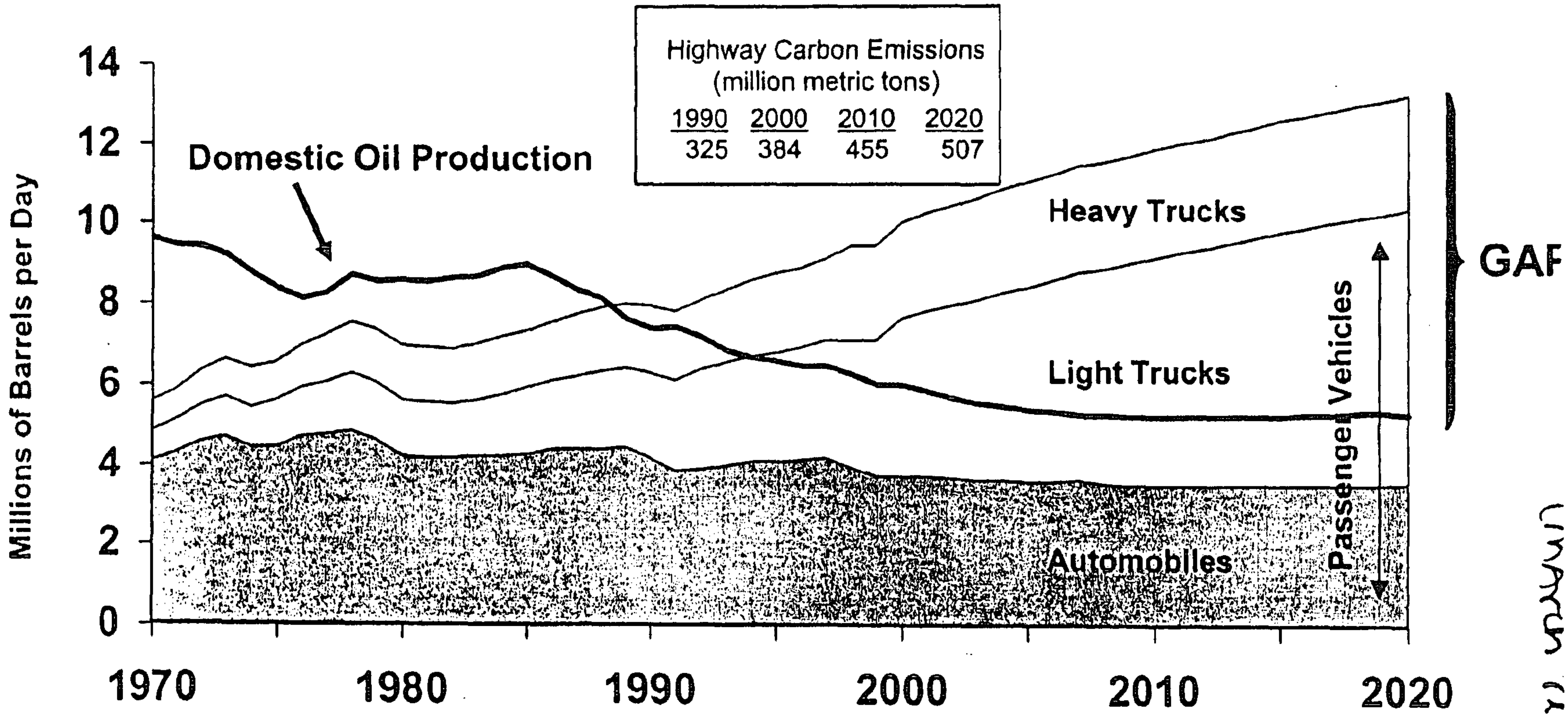
DOE024-0652

23246

Strength Through Science

Office of Transportation Technologies

Key Driver – Energy Security



Source: Transportation Energy Data Book: Edition 19, DOE/ORNL-6958, September 1999, and EIA Annual Energy Outlook 2000, DOE/EIA-0383(2000), December 1999

2

by state

1-4

	Solar* Insolation per day (kWh/m^2)	Wind (MW)	Geothermal	Biomass
Alabama	4.9	-		
Alaska	3.0	N/A		
Arizona	6.4	2,793		
Arkansas	5.1	9,754		
California	5.6	32,063		
Colorado	5.8	219,003		
Connecticut	4.4	4,409		
Delaware	4.6	2,127		
Florida	5.2	-		
Georgia	5.1	447		
Hawaii	5.6	N/A		
Idaho	5.1	25,414		
Illinois	4.6	46,864		
Indiana	4.4	191		
Iowa	4.7	379,650		
Kansas	5.3	722,389		
Kentucky	4.5	340		
Louisiana	5.0	-		
Maine	4.4	3,537		
Maryland	4.6	2,467		
Massachusetts	4.6	15,149		
Michigan	4.2	32,417		
Minnesota	4.4	412,691		
Mississippi	5.0	-		
Missouri	4.9	35,990		
Montana	4.7	430,584		
Nebraska	5.1	586,652		
Nevada	5.9	8,336		
New Hampshire	4.6	3,034		
New Jersey	4.6	6,635		
New Mexico	6.2	130,272		
New York	4.2	43,972		
North Carolina	5.0	2,396		
North Dakota	4.7	613,022		
Ohio	4.2	2,602		
Oklahoma	5.3	468,608		
Oregon	4.3	20,621		
Pennsylvania	4.3	28,958		
Rhode Island	4.5	369		
South Carolina	5.1	291		
South Dakota	5.0	518,393		
Tennessee	4.8	1,042		
Texas	5.4	722,460		
Utah	5.6	8,741		
Vermont	4.3	3,098		
Virginia	4.9	5,784		

23248

Washington	4.0	19,275
West Virginia	4.3	4,154
Wisconsin	4.5	39,953
Wyoming	5.4	365,132

Solar + wind data by state

2-4

*The solar insolation is the mid point of the highest insolation range covering a significant portion of the s

Solar & wind Ref.
by State

3-4

tates population as shown on the NREL average annual solar insolation for flat-plate set at latitude plu 1

23250

DOE024-0656

Solar and wind data by State

4-11

5 degrees.

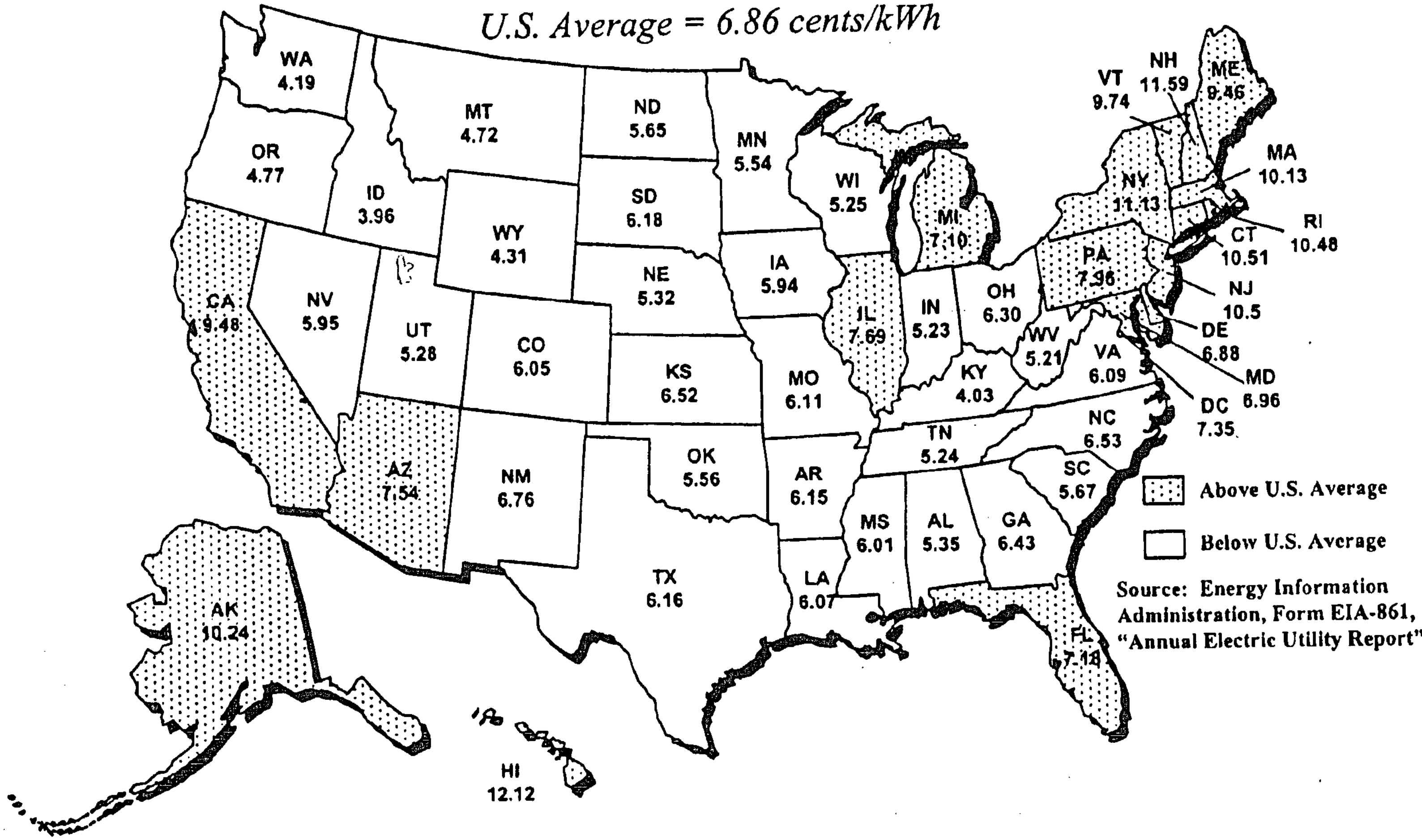
23251

DOE024-0657

3

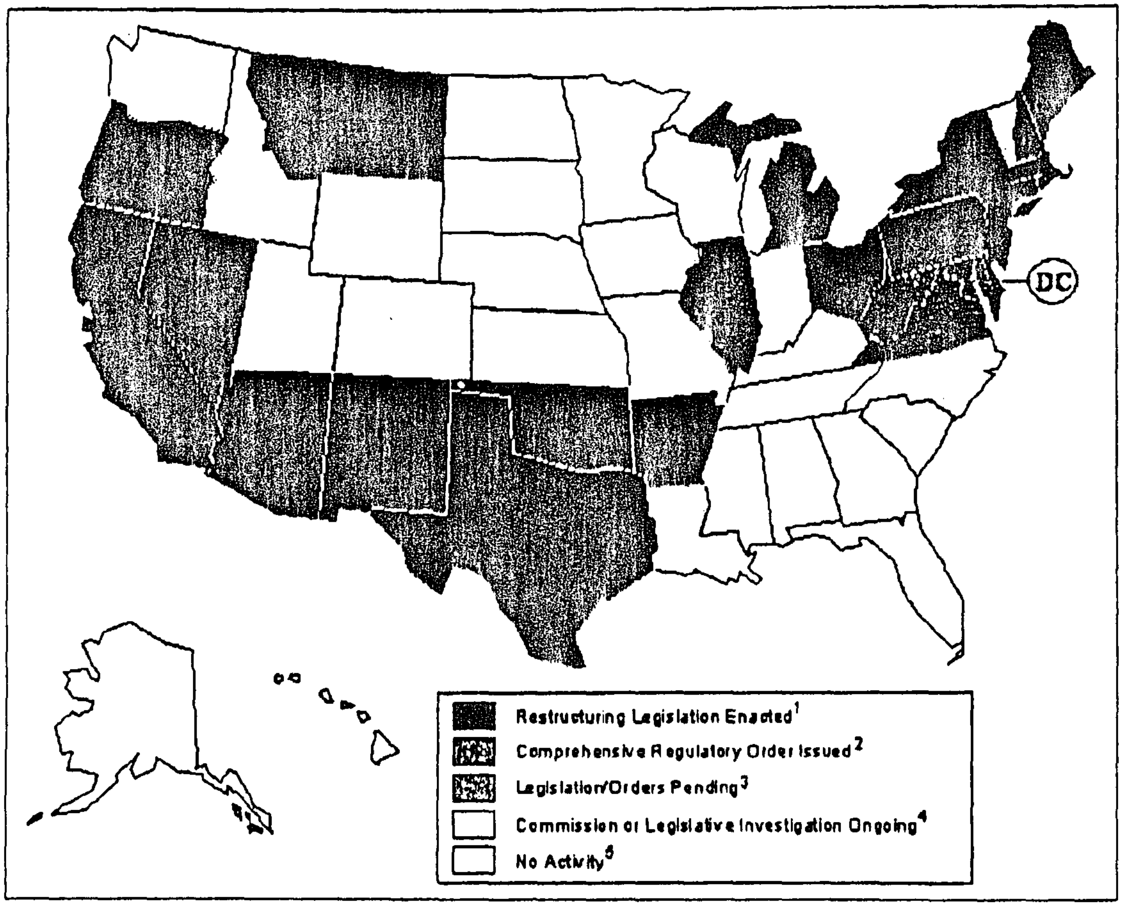
1996 Price of Electricity in the U.S.

U.S. Average = 6.86 cents/kWh



DOE024-0658

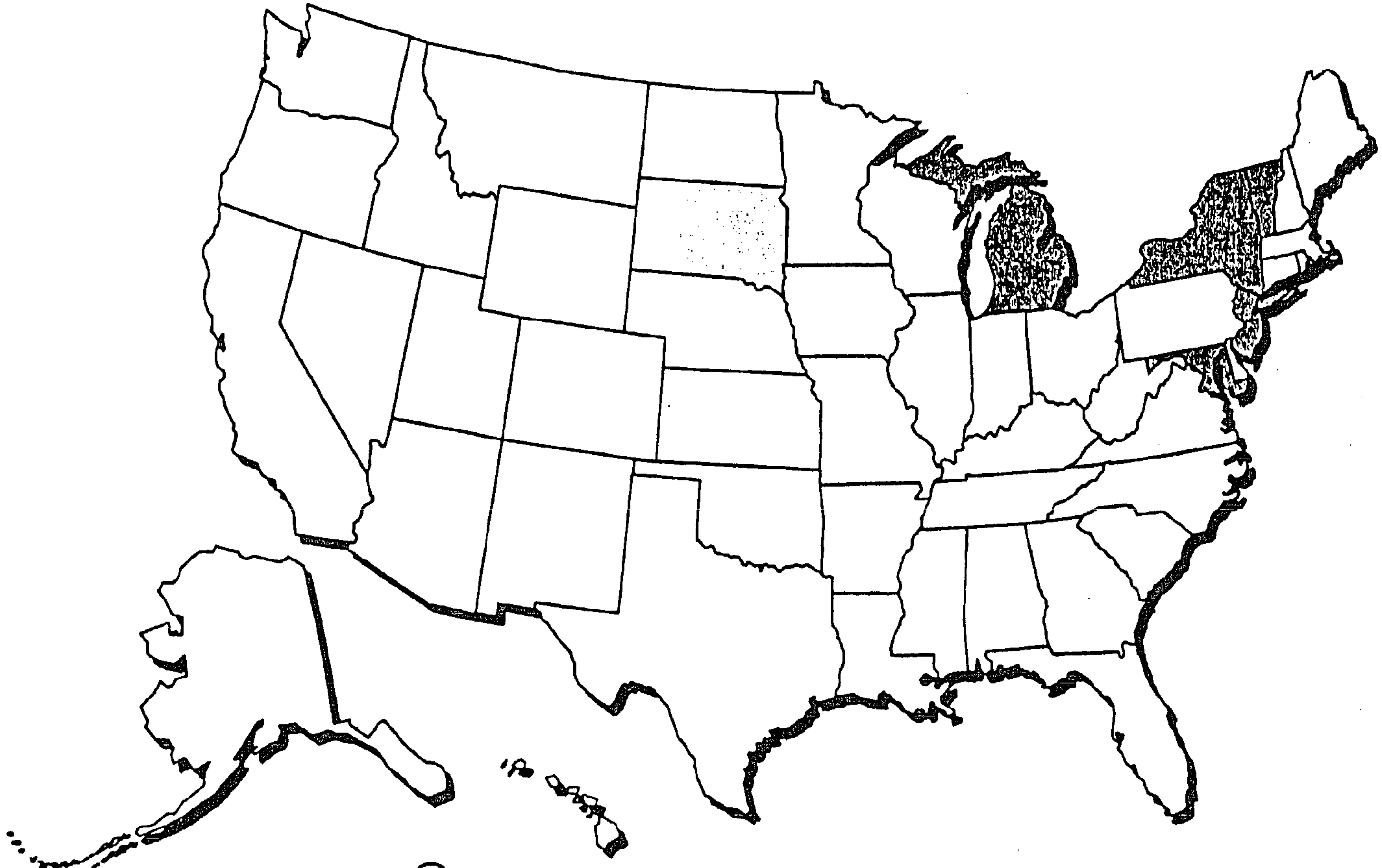
23252



DOE024-0659

23253

Overview of State Restructuring Actions



Legislation Enacted — Comprehensive Regulatory Order Issued — Legislation/Orders Pending

Commission or Legislative Investigation Ongoing — No Significant Activity

Source: EERE/EIA State-by-State Utility Restructuring Database, 1/99

color MA1

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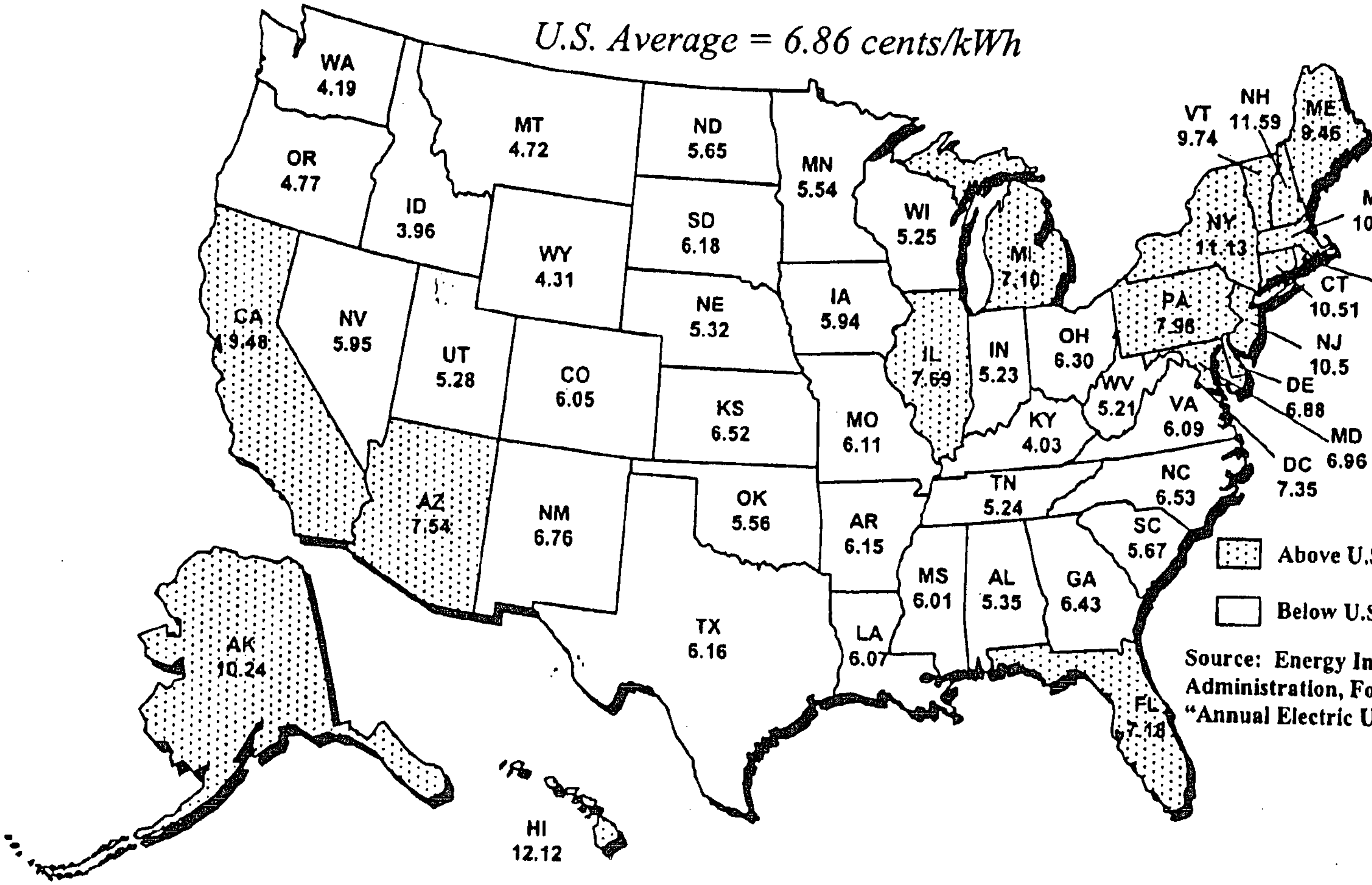


Above U.S. Average

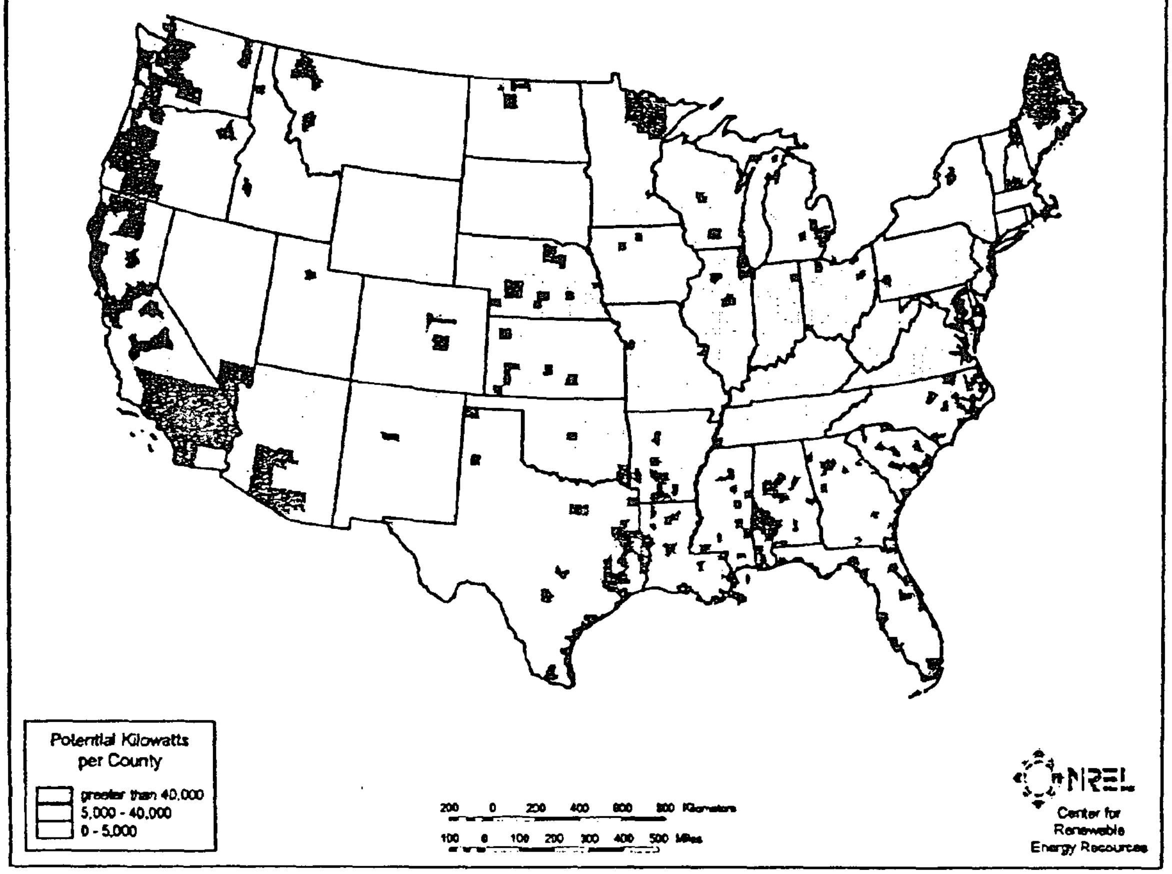
Below U.S. Average

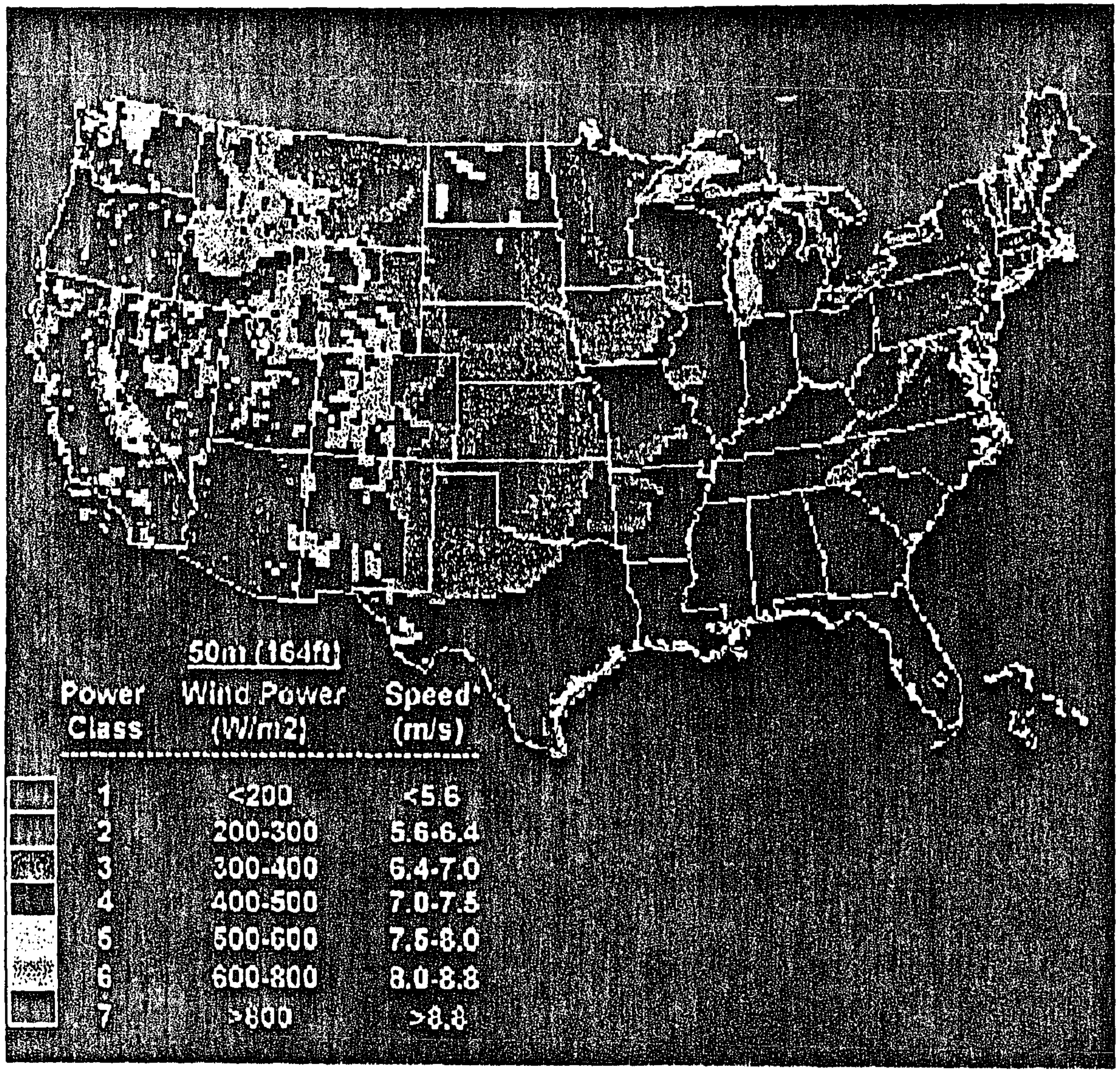
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report"

DOE024-0661

23255

Biomass and Biofuels Resource Potential

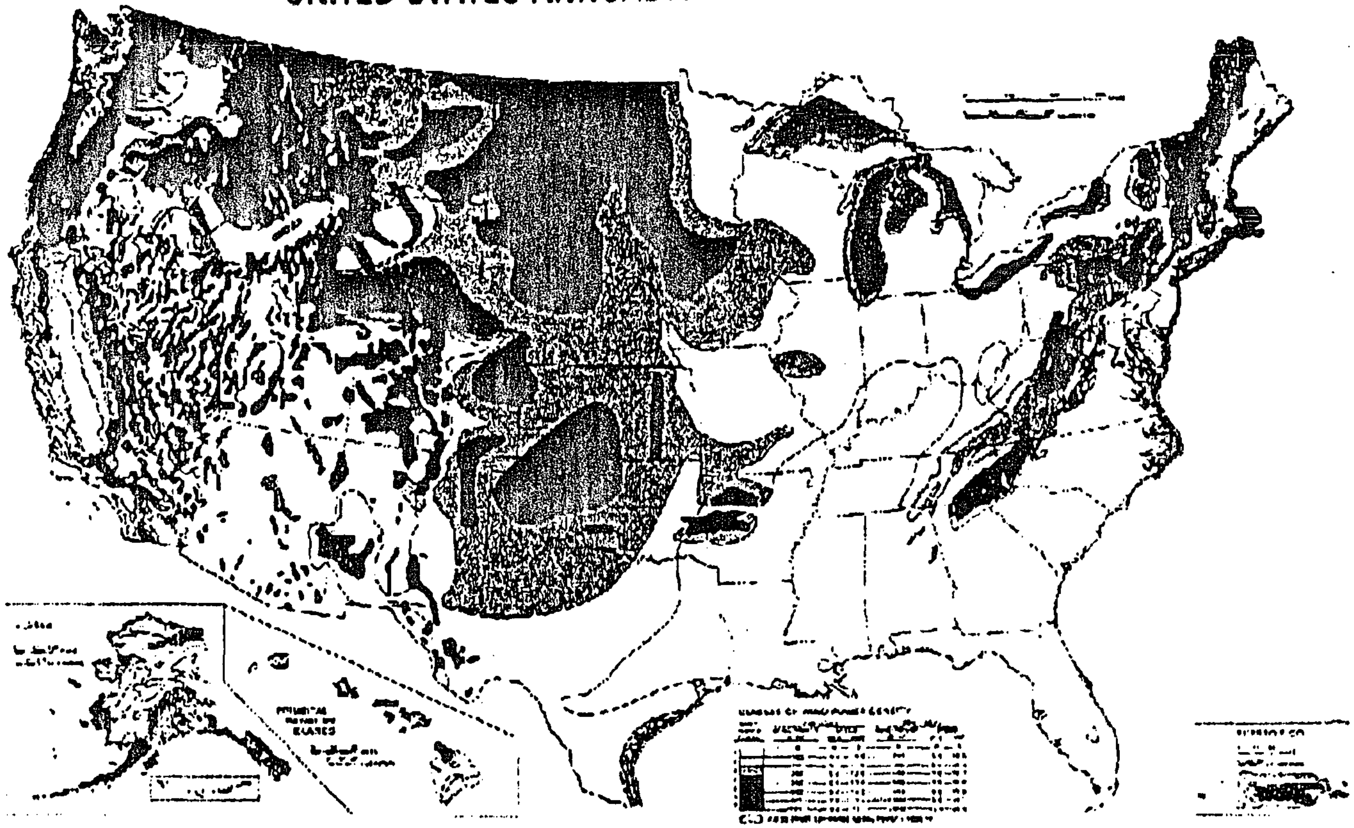


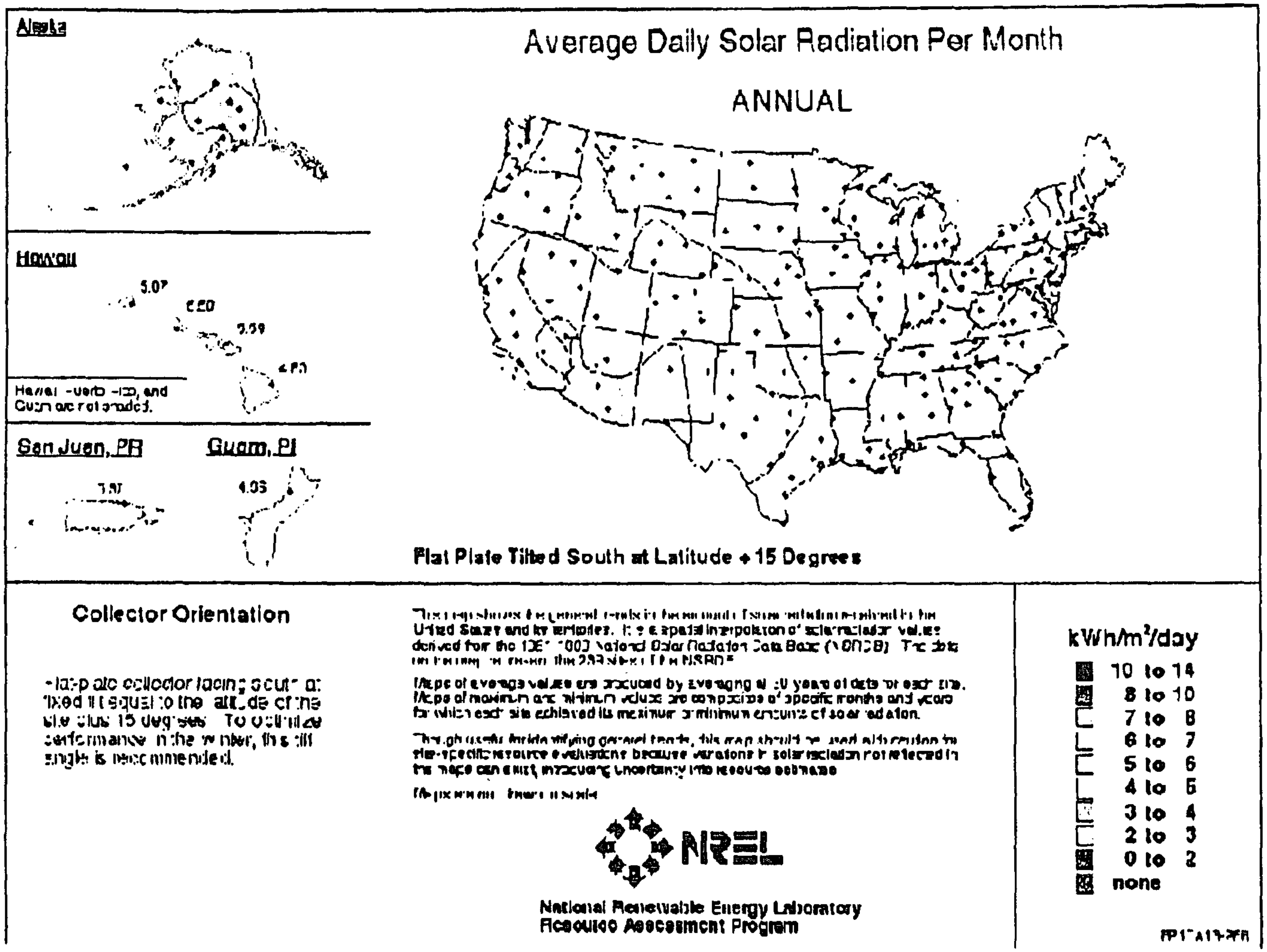


DOE024-0663

23257

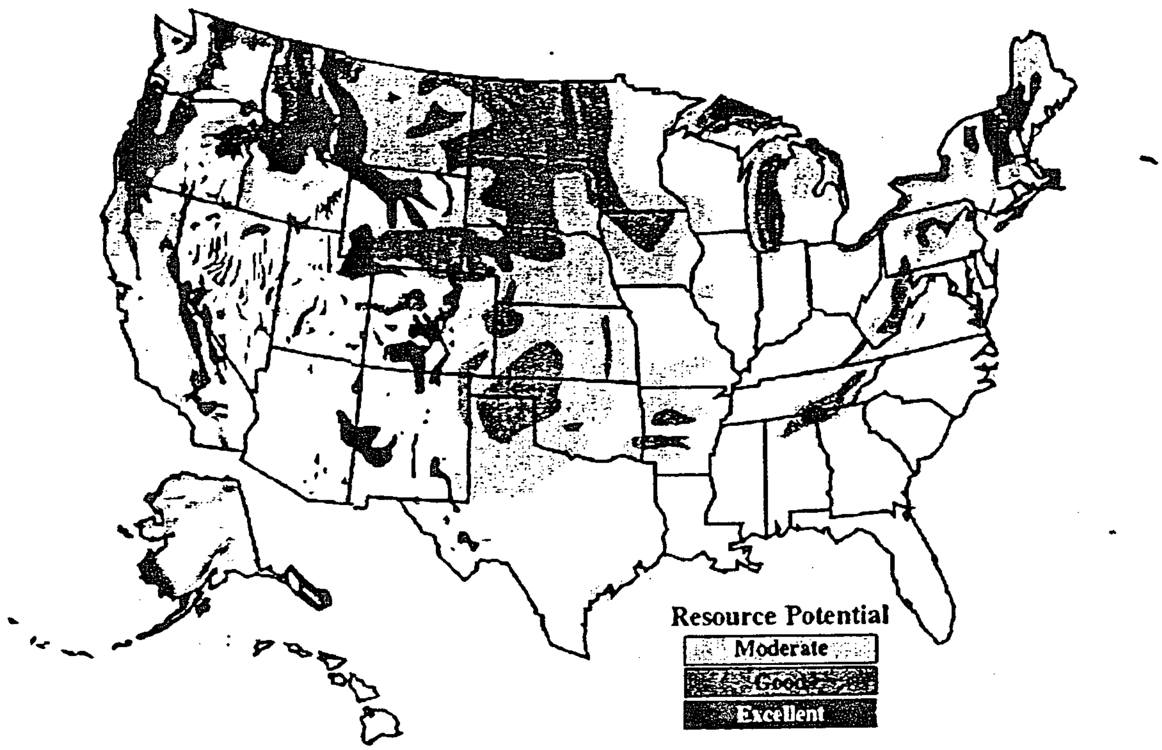
UNITED STATES ANNUAL AVERAGE WIND POWER





DOE024-0665

23259



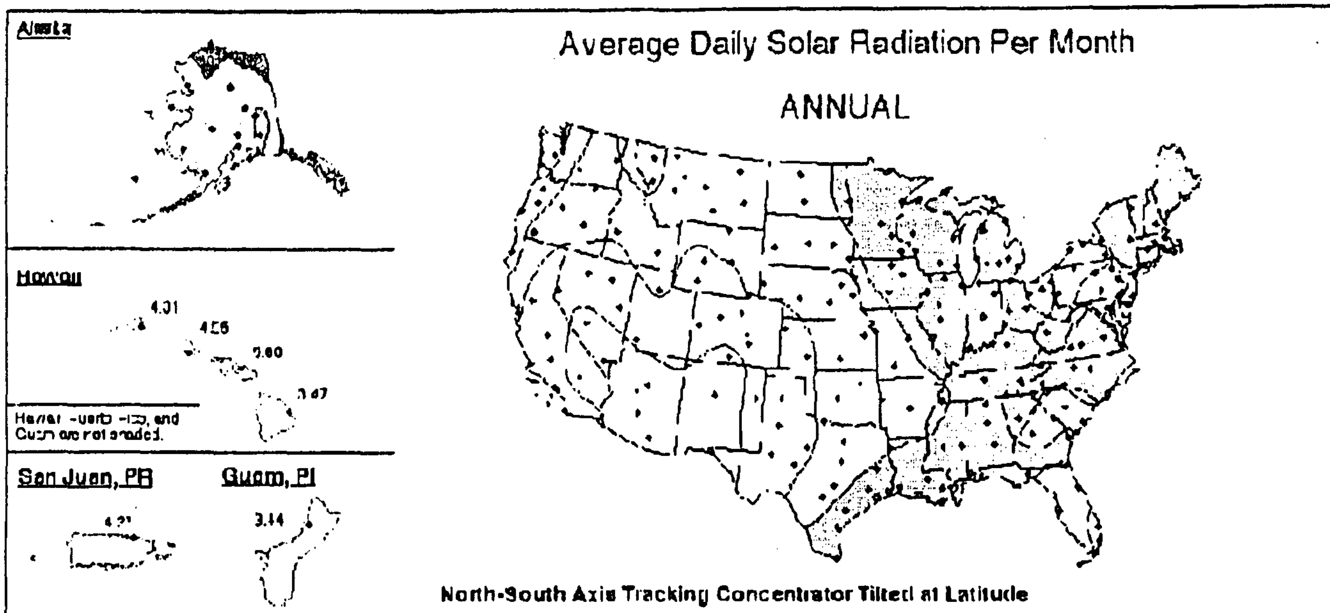
23260

DOE024-0666

12

Average Daily Solar Radiation Per Month

ANNUAL



North-South Axis Tracking Concentrator Tilted at Latitude

Collector Orientation

One axis tracking parabolic trough with a horizontal north-south axis and tilted from the horizontal at an angle equal to the site's latitude

This map shows the general trends in the amount [illegible] received in the United States and its territories. It is a spatial interpolation of solar radiation values derived from the 1961-1990 National Solar Radiation Data Base (NSRDB). The data [illegible] the 239 sites [illegible] NSRDB.

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[illegible]

NREL

National Renewable Energy Laboratory
Resource Assessment Program

kWh/m²/day

- 10 to 14
- 8 to 10
- 7 to 8
- 6 to 7
- 5 to 6
- 4 to 5
- 3 to 4
- 2 to 3
- 0 to 2
- none

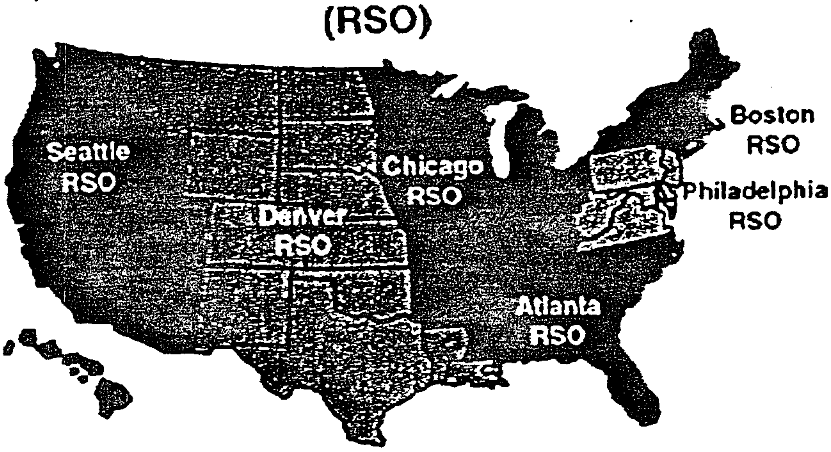
[illegible]

DOE024-0667

23261

13

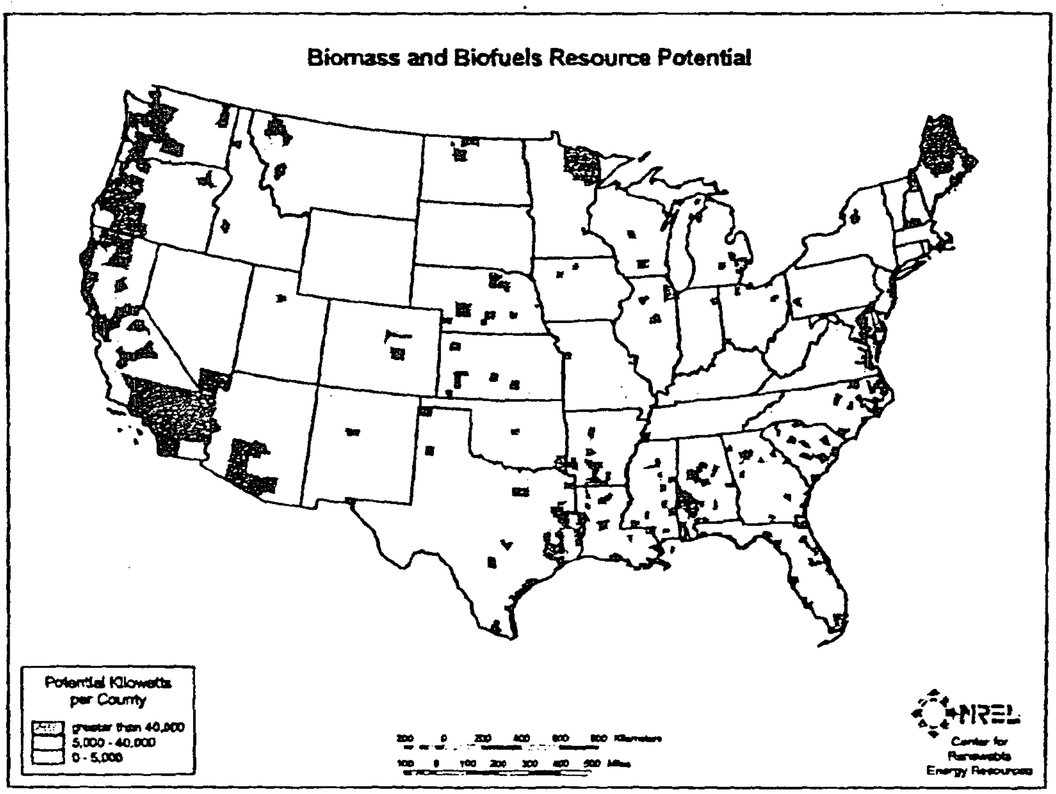
Department of Energy Regional Support Offices (RSO)



23262

DOE024-0668

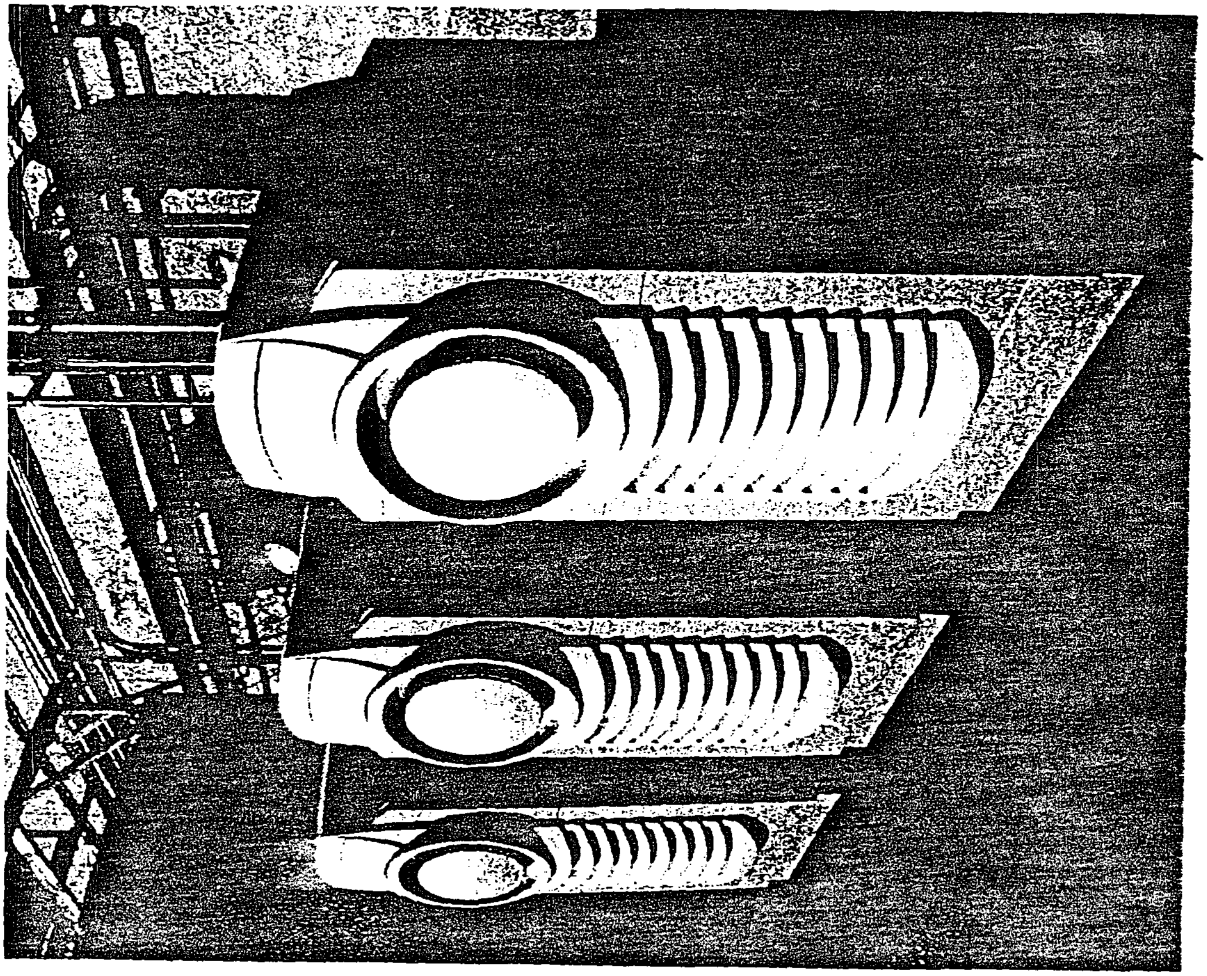
biomass



23263

DOE024-0669

Microturbines



23264

DOE024-0670

Lead Entity	**Programs/ Initiatives Impacted**	**Description of Impacted Program/ Initiative**	**Sector Comments**
All			
NEDP			
DOE			
DOE			
DOE			
DOE			

DOE024-0755

23349

All			
DOE, State, Commerce			
DOE, State, Commerce			
DOE, USTR, Commerce			
DOE, State, Commerce			

DOE024-0756

23350

DOE, State, Commerce			
All			
DOE			
All			

DOE024-0757

23351

White House			
White House			
DOT			
DOT			
DOT			

Lead Entity	Programs/ Initiatives Impacted	Description of Impacted Program/ Initiative	Sector Comments
All			
NEDP			
DOE			
DOE			
DOE			
DOE			

DOE, State, Commerce			
All			
All			
White House			
White House			
AG			

DOE024-0761

23355

Lead Entity	Programs/ Initiatives Impacted	Description of Impacted Program/ Initiative	Sector Comments
DOE			
DOE			
DOE			
DOE			
DOE			
DOE			
All			

NEDP			
DOE			
DOE			
DOE			
DOE			
All			

DOE, State, Commerce			
DOE, State, Commerce			
DOE, USTR, Commerce			
DOE, State, Commerce			
DOE, State, Commerce			

All			
EPA			
White House			
All			
White House			
White House			

DOE024-0769

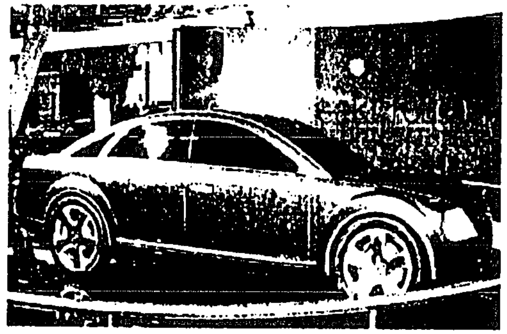
23363

2000 Washington DC

<u>Dodge ESX3</u>

- Body system weighs 46% less*
- Efficient diesel engine, motor and battery achieve 72 mpg*
- Incremental cost penalty halved

2000 Detroit Auto Show



<u>Ford Prodigy</u>

- Better than 70 mpg
- Lightweight materials reduce vehicle weight 30% *
- Integrated starter/alternator *
- 33% reduction in aerodynamic drag
- Advanced diesel engine with 35% efficiency improvement *
- High power battery *

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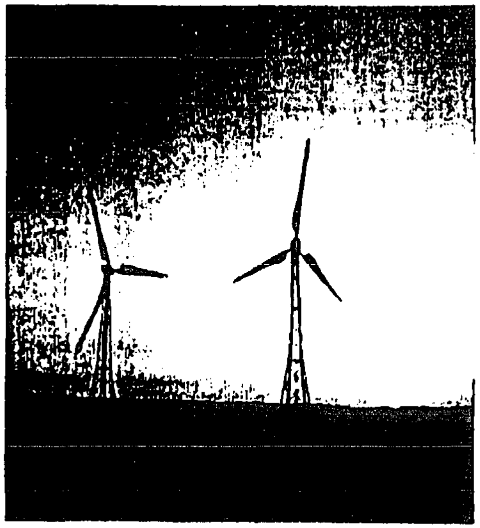
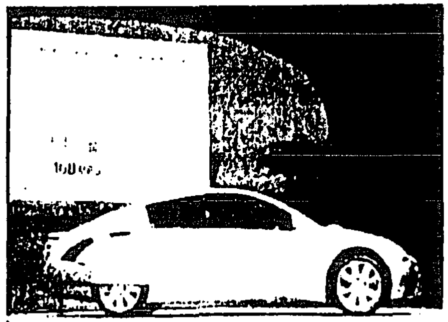
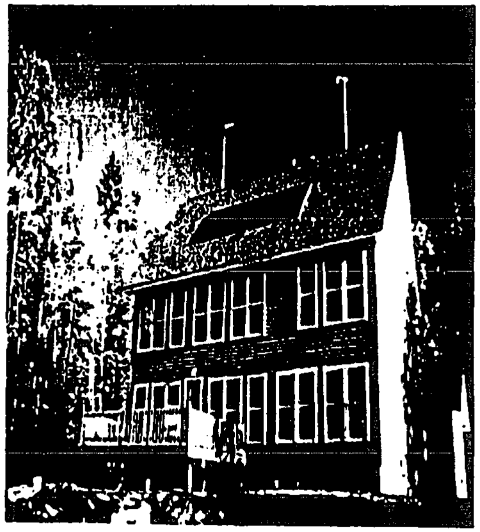


2000 Detroit Auto Show



__GM Precept__
- Vehicle mass reduced 45% *
- Eliminates need for power steering
- Lowest drag coefficient ever recorded for a 5-p sedan
- Fuel cell version projected to get 108 mpg *



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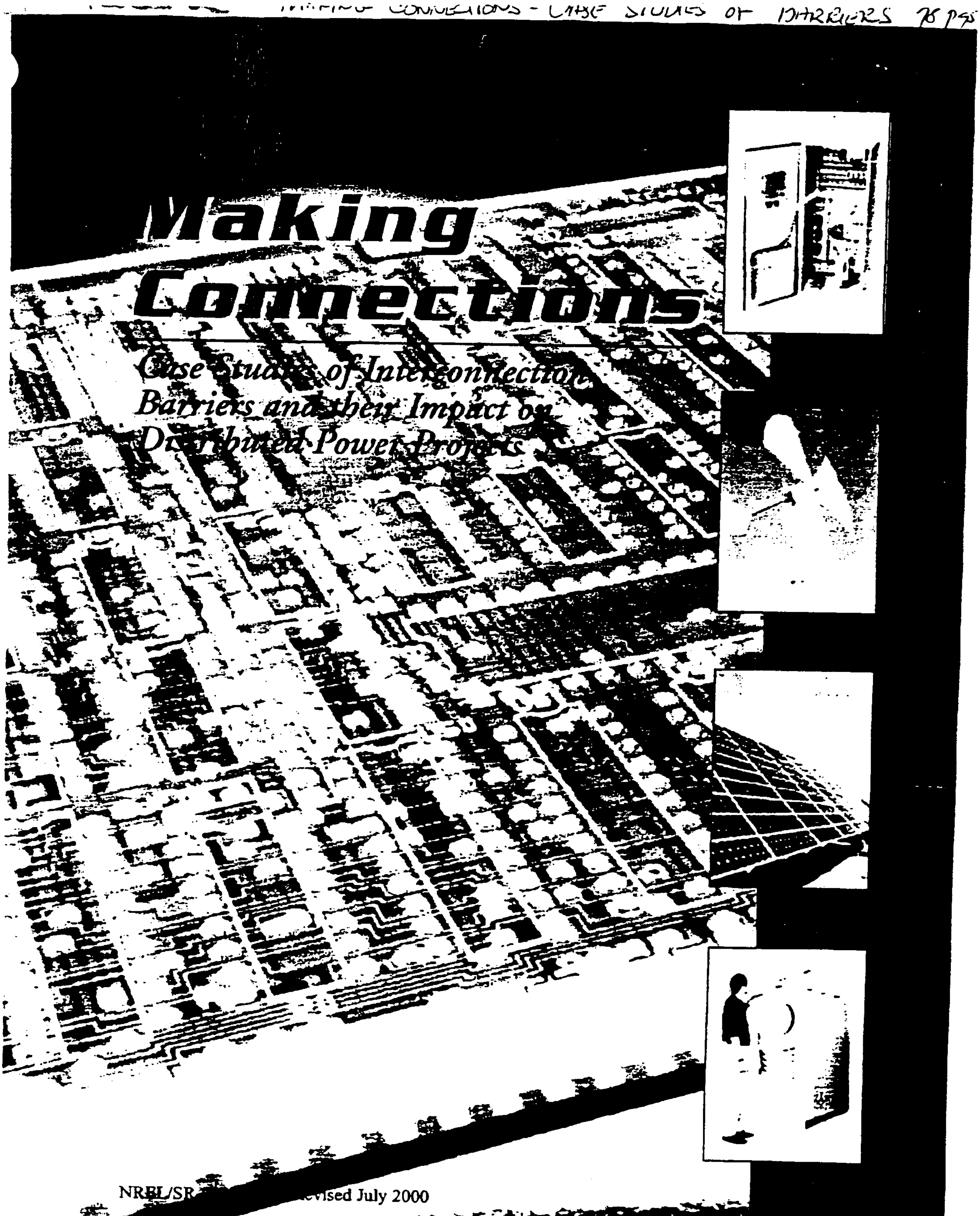
Making Connections - Case Studies of Barriers 78 pgs



Making Connections

Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects

NREL/SR... Revised July 2000

23374

DOE024-0780

United States Department Of Energy Distributed Power Program
Office of Energy Efficiency and Renewable Energy, Office of Power Technologies

Joseph Galdo
DOE Distributed Power Program Manager
Office of Power Technologies, EE-15
U.S. Department of Energy
Forrestal Building, 5H-021
1000 Independence Avenue SW
Washington, DC 20585
Phone: (202) 586-0518
Fax: (202) 586-1640

Richard DeBlasio
NREL Distributed Power Program Manager
National Renewable Energy Laboratory
1617 Cole Blvd. (MS 3214)
Golden, CO 80601
Phone: (303) 384-6452
Fax: (303) 384-6490

Gary Nakarado*
National Renewable Energy Laboratory
NREL Distributed Power Program Technical Monitor
1617 Cole Blvd. (MS 3214)
Golden, CO 80601
Phone: (303) 384-7468
Email: Gary_Nakarado@nrel.gov

*Contact for questions or comments on this report.

ABOUT THE AUTHORS

R. BRENT ALDERFER

R. Brent Alderfer is a leading national spokesperson on regulatory issues affecting distributed generation and renewable energy markets. He recently launched Community Energy, Inc., a wind energy marketing company entering the competitive electric markets. A former state utility commissioner, he served as Chair of the Energy Resources and Environment Committee of the National Association of Regulatory Utility Commissioners, where he launched the association's distributed power regulatory initiatives. He is an electrical engineer and a lawyer, a graduate of Georgetown University Law School.

THOMAS J. STARRS

Thomas J. Starrs is a principal in the energy and environmental consulting firm of Kelso Starrs & Associates LLC, based on Vashon Island, Washington. His consulting practice focuses on the design, analysis and implementation of legal and regulatory incentives for the development of distributed power technologies, with a focus on solar and wind energy. Tom has spoken before state legislative committees, public utility commissions, and state energy offices in over a dozen states, and has made invited presentations to numerous national organizations about distributed power. He holds a Ph.D. from U.C. Berkeley's Energy & Resources Group, and a law degree from U.C. Berkeley's Boalt Hall School of Law.

M. MONIKA ELDRIDGE, PE

Ms. Eldridge is a principal with Competitive Utility Strategies, LLC where she is currently developing distributed generation and renewable energy projects as well as evaluating the economics and technical feasibility of distributed generation. During her 18 year career in the power generation industry, she has assisted utilities in strategic planning of major power plant facilities and worked as a project manager for CMS Energy. She has a BS in mechanical and aerospace engineering from the University of Delaware and is a registered professional engineer.

Cover photos (top to bottom):

The *en*power-APS Automatic Paralleling Switchgear is an example of new equipment available for interconnecting to the grid. Courtesy of ENCORP, Inc. NREL PIX #09125

At 10-kW, the BWC Excel Wind Turbine is an appropriate size for small distributed power generation projects. Courtesy of Bergey Wind Power Co., Inc. NREL PIX #02102.

PV Systems such as these modules installed near Fresno, California, can be built to whatever size is appropriate for a distributed generation project. Photo by Terry O'Rourke. NREL PIX #00252.

The Capstone Microturbine is an example of new small-scale generating equipment available for distribution power generation. Courtesy of Capstone Turbine Corporation. NREL PIX #08130

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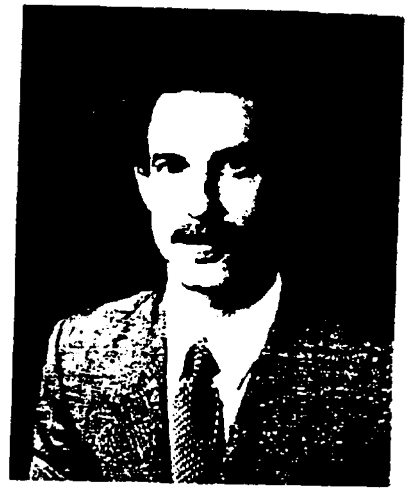
Foreword

Today there is growing interest in distributed electricity generation, particularly onsite generation. This interest is stimulated by the reliability, power quality, and environmental needs of business and homeowners, as well as the availability of more efficient, environmentally-friendly, modular electric generation technologies, such as microturbines, fuel cells, photovoltaics, and small wind turbines.



This report documents the difficulties faced by distributed generation projects seeking to connect with the electricity grid. The distributed generation industry has told us that removing these barriers is their highest priority. The case studies treated in this report clearly demonstrate that these barriers are real. They are, in part, an artifact of the present electricity industry institutional and regulatory structure which was designed for a vertically integrated utility industry relying on large central station generation.

It is essential that energy and environmental policy reform accompany continued technological improvement in order to bring the many benefits of distributed power systems to our Nation. The challenge for us today, as the authors of this report suggest, is to seize the opportunity offered by the current restructuring of the electricity industry to create a new electricity system that supports, rather than stymies, the distributed generation.

We in the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy look forward to working with you, our customers, in meeting this challenge.

Dan W. Reicher
Assistant Secretary of Energy
Energy Efficiency and Renewable Energy

Executive Summary

Environmentally-friendly renewable energy technologies such as wind turbines and photovoltaics and clean, efficient, fossil-fuel technologies such as gas turbines and fuel cells are among the fleet of new generating technologies driving the demand for distributed generation of electricity. Combined heat and power systems at industrial plants or commercial buildings can be three times more efficient than conventional central generating stations. When facilities such as hospitals and businesses with computers or other critical electronic technology can get power from either the grid or their own generating equipment, energy reliability and security are greatly improved.

Distributed power is modular electric generation or storage located close to the point of use. It can also include controllable load. This study focuses primarily on distributed generation projects. Distributed generation holds great promise for improving the electrical generation system for the United States in ways that strongly support the primary energy efficiency and renewable energy goals of the U.S. Department of Energy (DOE). Distributed generation offers customer benefits in the form of increased reliability, uninterruptible service, energy cost savings, and onsite efficiencies. Electric utility operations can also benefit. Smaller distributed-generation facilities can delay or eliminate the need to build new large central generating plants or transmission and distribution lines. They can also help smooth out peak demand patterns, reduce transmission losses, and improve quality of service to outlying areas.

However, overlaying a network of small, non-utility owned (as well as utility-owned) generating facilities on a grid developed around centralized generation requires innovative approaches to managing and operating the utility distribution system, at a time when actual or anticipated deregulation has created great uncertainty that sometimes discourages adoption of new policies and practices.

In December 1998, DOE sponsored a meeting of the stakeholders in distributed generation. The need to document the nature of the entry barriers for distributed power technologies became clear. Customers, vendors, and developers of these technologies cited interconnection barriers—including technical issues, institutional practices, and regulatory policies—as the principal obstacles separating them from commercial markets. Industry and regulatory officials are also beginning to examine the nature and extent of these barriers and to debate the appropriate responses.

This report reviews the barriers that distributed generators of electricity are encountering when attempting to interconnect to the electrical grid. The authors interviewed people who had previously sought or were currently seeking permission to interconnect. This study focuses on the perspective of the project proponents. No attempt was made to assess the prevalence of the barriers identified.*

By contacting people known to be developing distributed generation projects or to be interested in these projects, and then gathering referrals from those people, the authors were able to identify 90 potential projects for this study. Telephone interviews were then conducted with people involved with those 90 projects. For smaller projects, this was usually the customer or owner of the project. For larger projects, this was usually a distributed generation project developer building the facility for the customer. The authors obtained sufficient information about 65 of the 90 projects to develop full case studies for these projects. The sizes of the projects represented by the case studies range from 26 megawatts to less than a kilowatt.

Most of the distributed power case studies experienced significant market entry barriers. Of the 65 case studies, only 7 cases reported no major utility-related barriers and were completed and interconnected on a satisfactory timeline. For the remaining case studies, the project proponents expressed some degree of dissatisfaction in dealing with the utility. They believed that the utilities' policies or practices constituted unnecessary barriers

* The purpose and value of the study was simply to confirm that barriers do exist, to provide illustrative examples of current case studies, and to initially identify the kinds of barriers. The authors made no attempt to obtain a statistically valid or unbiased sample. Also, the use of referrals to select case studies for identifying barriers likely skewed the selection toward cases where there were barriers.

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Findings

This report focuses on cases where barriers were present and does so from the project proponents' perspective. Nonetheless, the study offers the following findings about current barriers to interconnection of distributed power generation projects.

- A variety of technical, business practice, and regulatory barriers discourage interconnection in the US domestic market.
- These barriers sometimes prevent distributed generation projects from being developed.
- The barriers exist for all distributed-generation technologies and in all regions of the country.
- Lengthy approval processes, project-specific equipment requirements, or high standard fees are particularly severe for smaller distributed generation projects.
- Many barriers in today's marketplace occur because utilities have not previously dealt with small-project or customer-generator interconnection requests.
- There is no national consensus on technical standards for connecting equipment, necessary insurance, reasonable charges for activities related to connection, or agreement on appropriate charges or payments for distributed generation.
- Utilities often have the flexibility to remove or lessen barriers.
- Distributed generation project proponents faced with technical requirements, fees, or other burdensome barriers are often able to get those barriers removed or lessened by protesting to the utility, to the utility's regulatory agency, or to other public agencies. However, this usually requires considerable time, effort, and resources.
- Official judicial or regulatory appeals were often seen as too costly for relatively small-scale distributed generation projects.
- Distributed generation project proponents frequently felt that existing rules did not give them appropriate credit for the contributions they make to meeting power demand, reducing transmission losses, or improving environmental quality.

to interconnection. As of completion of the report, 29 of the case study projects had been completed and interconnected; 9 were meeting only the customer's load and were not sending any power to the grid; 2 had disconnected from the grid; 7 had been installed, but were still seeking interconnection (and may be operating independently in the interim); 13 were pending; and 5 projects had been abandoned.

For purposes of this analysis, the barriers encountered in the case studies were classified as technical, business practice, or regulatory.

Technical barriers consist principally of utility requirements to ensure engineering compatibility of interconnected generators with the grid and its operation. Most significant of the technical barriers are requirements for protective equipment and safety measures intended to avoid hazards to utility property and personnel, and to the quality of power in the system. Proponents of potential distributed generation systems often stated that the required equipment and custom engineering analyses are unnecessarily costly and duplicative. Such requirements added $1200 or 15% to the cost of a 0.9 kW photovoltaics project, for example, plus an additional $125 per year for relay calibration. Newer generating equipment already incorporates technology designed specifically to address safety, reliability, and power-quality concerns.

Business-practice barriers arise from contractual and procedural requirements for interconnection and, often times, from the simple difficulty of finding someone within a utility who is familiar with the issues and authorized to act on the utility's behalf. This lack of utility experience in dealing with such issues may be one of the most widespread and significant barriers to distributed generation, particularly for small projects. Utilities that set up standard procedures and designate a point of contact for distributed generation projects considerably simplify and reduce the cost of the interconnection process both for themselves and for the distributed generation project proponents.

Other significant business-practice barriers included procedures for approving interconnection, application and interconnection fees, insurance requirements, and operational requirements. Many project proponents complained about the length of time required for getting projects approved. Seventeen projects—more than 25% of the case studies—experienced delays greater than 4 months. Smaller projects often faced a lack of uniform standards, procedures, and designated utility points of contact for determining a particular utility's technical requirements and review processes. This led to prohibitively long and costly approvals. Proponents of larger projects sometimes formed the perception that the utility was deliberately dragging out negotiations. Application and interconnection fees were frequently viewed as arbitrary and, particularly for smaller projects, disproportionate. Utility-imposed operational requirements sometimes resulted in direct conflicts between utility and customer needs. For example, utilities often ask to control the facility so that, among other things, they can shut down the facility for safety purposes during power outages. This requirement would preclude the customer using the facility for emergency backup power—a key advantage of distributed generation.

Regulatory barriers were principally posed by the tariff structures applicable to customers who add distributed generation facilities, but included outright prohibition of "parallel operation"—that is, any use other than emergency backup when disconnected from the grid. The tariff issues included charges and payments by the utility and how the benefits and costs of distributed generation should be measured and allocated. Also, several project proponents reported being offered substantial discounts on their electrical service from the utility as an inducement not to build their planned distributed generation facilities.

Backup or standby charges were the most frequently cited rate-related barrier. Unless distributed generation customers want to disconnect completely from the grid and invest in the additional equipment needed for emergency backup and peak needs, they will be depending on the utility to augment their onsite power generation. This is a principal reason for interconnection, but it can also impose a burden on the utility because it may be required to maintain otherwise unnecessary capacity to meet the distributed generation customers' occasional added demand. Charges for these services varied widely. Standby charges ranged from \$53.34/kW-yr to \$200/kW-yr for just the case study projects located in the state of New York, for example. Project proponents often felt that the charges were excessive and that utility concerns could be addressed through scheduling and other procedures. Other frequently disputed charges included transmission and distribution demand charges and exit fees (charges to disconnecting customers that will no longer be supporting the payoff of the utility's sunk or "stranded" cost in generation equipment). Furthermore, the charges imposed often do not reflect the benefits to the grid the distributed generation might provide.

For small customers, net metering (where the meter runs backwards when power is being contributed to the grid—prescribed by law in about 30 states) provides credit at the retail rate. For large distributed generation facilities, however, the typically much-lower wholesale rate paid (or uplift charge assessed for using transmission and distribution systems to sell power to third parties in deregulated states) was often seen as unfair, especially if no credit was given for on-peak production. Project proponents felt that utilities were not giving them credit for their contribution to helping meet peak demands.

Environmental permitting was not a focus of this report, but many project proponents did cite it as a regulatory barrier. Inconsistent requirements from state to state and site to site were frequently listed as barriers. The length of time and cost of testing to comply with air quality standards was often seen as burdensome and unfair. Proponents also felt that permitting processes should give credit for the replacement of older, more polluting, facilities by the distributed generation projects (e.g. a gas turbine instead of a central station coal-fired plant) as well as the increased efficiencies, for example, of a combined heat and power facility.

The case studies identified a wide range of barriers to grid interconnection of distributed generation projects. These barriers unnecessarily delay and increase the cost of what otherwise appear to be viable projects with potential benefits to both the customer and the utility system. They sometimes even kill projects. There are, however, several promising trends. Uniform technical standards for interconnection are being developed by the Institute of Electrical and Electronics Engineers. Individual state regulatory agencies are adopting rules to address barriers to distributed generation. In 1999, the New York and Texas public utility commissions adopted landmark rules on interconnection, and ambitious proceedings on distributed generation are now underway in California. Individual utilities have adopted programs to promote distributed generation. These trends indicate the potential for resolution of barriers to interconnection of distributed generation projects.

Much more must be done in order to create a regulatory, policy, and business environment which does not create artificial market barriers to distributed generation. The barriers distributed generation projects face today go beyond the problems of technical interconnection standards or process delay, which are more immediately apparent to the market. They grow out of long-standing regulatory policies and incentives designed to support monopoly supply and average system costs for all ratepayers.
In the present regulatory environment, utilities have little or no incentive to encourage distributed power. To the contrary, regulatory incentives drive the distribution utility to defend the monopoly against market entry by distributed power technologies. Revenues based on throughput and system average pricing are optimized by keeping maximum loads and highest revenue customers on the system. But, as in any competitive market, those are the customers that gain the most by switching to new, more economic, efficient, or customized power alternatives. In addition, current tariffs and rate design as a rule do not price distribution services to account for system benefits that could be provided by distributed generation.

Resolution on a state-by-state basis will not address what may be the biggest barrier for distributed generation—a patchwork of rules and regulations which defeat the economies of mass production that are natural to these small modular technologies. Although regulatory proceedings and legal challenges eventually would resolve most of the identified barriers, national collaborative efforts among all stakeholders are necessary to accelerate this process so that near-term emerging markets for the new distributed generation technologies are not stymied.

Distributed generation promises greater customer choice, efficiency advantages, improved reliability, and environmental benefits. Removing artificial barriers to interconnection is a critical step toward allowing distributed generation to fulfill this promise.

A Ten-Point Action Plan For Reducing Barriers to Distributed Generation

Reduce Technical Barriers

(1) Adopt uniform technical standards for interconnecting distributed power to the grid.

(2) Adopt testing and certification procedures for interconnection equipment.

(3) Accelerate development of distributed power control technology and systems.

Reduce Business Practice Barriers

(4) Adopt standard commercial practices for any required utility review of interconnection.

(5) Establish standard business terms for interconnection agreements.

(6) Develop tools for utilities to assess the value and impact of distributed power at any point on the grid.

Reduce Regulatory Barriers

(7) Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets.

(8) Adopt regulatory tariffs and utility incentives to fit the new distributed power model.

(9) Establish expedited dispute resolution processes for distributed generation project proposals.

(10) Define the conditions necessary for a right to interconnect.

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SECTION 1. INTRODUCTION AND METHODOLOGY

1.1 Introduction

Distributed power is modular electric generation or storage located close to the point of use. It can also include controllable load. This study focuses primarily on distributed generation projects. The sizes of the projects described in this report ranged from 26 megawatts to less than a kilowatt.

The convergence of competition in the electric industry with the arrival of environmentally friendly microturbines, fuel cells, photovoltaics, small wind turbines, and other advanced distributed power technologies has sparked strong interest in distributed power, particularly in on-site generation. This convergence of policy and technology could radically transform the electric power system as we know it today. Like the revolution that took us from mainframe computers to PC's, this transformation could take us from a power system that relies primarily on large central station generation to one in which small electric power plants located in our homes, office buildings, and factories provide most of the electricity we use. The resulting major improvement in electric power reliability could save billions of dollars now lost each year because of power disruptions. The impressive efficiency and environmental gains offered by distributed power technologies have the potential to contribute significantly to mitigation of air pollution and global climate change. However, these distributed power technologies face an array of market entry barriers, which are the subject of this report.

At a Department of Energy (DOE) meeting of industry and public stakeholders in December 1998, the need to document the nature of the entry barriers for distributed power technologies became clear. Customers, vendors, and developers of these technologies cited interconnection barriers, including technical and related institutional and regulatory practices, as the principal obstacles separating them from commercial markets. As witnessed by the landmark rules adopted in 1999 by the New York and Texas public utility commissions, and the ambitious proceedings taking place in California, industry and regulatory officials are beginning to examine the nature and extent of these barriers, and to debate the appropriate response.

This study serves to document the reality of market entry barriers across the spectrum of distributed power technologies by providing case studies of distributed power projects that have been impacted by these market barriers. However, the focus is on barriers to interconnection with utility systems, and other important issues such as environmental permitting are not examined in detail in this report.

1.2 Methodology

Identifying Case Studies

The first challenge of the study was to identify grid-connected distributed power projects that would serve as subjects for the case studies. Representatives from trade associations, equipment manufacturers, distributed power project developers, utilities, utility regulators, state energy officials, and others in the distributed power industry were asked to identify projects that might be candidate case studies. Case study contacts also identified other possible case studies. Altogether more than 150 individuals were contacted during the course of this project.

These contacts identified more than 90 possible projects covering a broad range of fuel types, technologies, and sizes. For smaller projects, the information source was typically the project owner/electricity customer. For larger projects, it was typically a project developer. In a few cases, the equipment manufacturer was the source. The projects varied from those in the planning stages to those that were already in operation. Also included were projects that ultimately did not interconnect with the utility's grid or which were abandoned. Many of the projects were in the process of negotiation with the utilities for final interconnection. Some of projects were not included in this report because of a lack of complete or reliable information. Of the 90 projects, sufficient information was collected on 65 to treat them as case studies. The findings and analyses of this report are based on these 65 case studies.

NOTE: Given the scope of this project and the manner of locating the distributed power cases discussed, no claims are made as to the likelihood that the cases represent any particular scale of problem, nor that the categories in which we have placed individual cases are statistically valid in any formal sense. Rather, the cases report situations encountered in the marketplace today and convey, where available, the participant's suggestions about how to correct situations that hindered distributed power development.

Conducting Interviews

With assistance from the DOE and other distributed resource experts, an interview survey form (inserted on pages 3-4) was designed and used to document the 65 case studies that form the basis of this report.[1] Using this survey form to guide the conversation, we interviewed project information sources by telephone. The completed form was then E-mailed or faxed to the interviewee for verification when possible. Of the 65 case studies, we selected 26 as being representative of the barriers encountered and having sufficient information available to tell an illustrative story. These 26 cases are presented in detail in Section 3 of this report. To respect confidentiality concerns and to avoid undue emphasis on the specifics of any single case study, the names of distributed power owners, specific facility locations, equipment vendors, and interconnecting utilities are excluded from the case study narratives. This report focuses on the nature and scope of interconnection barriers in the U.S domestic market, rather than practices of any particular utility or stakeholder.

Utility Verification

For each of the 26 projects detailed in Section 3, the interconnecting utility was contacted—first to validate information provided by the owners or developers, and second to document the utility's opinions and recommendations. In instances where the project developer or owner desired to remain anonymous, the details of these projects were not discussed with the utility. Instead, generic questions regarding the utility's distributed power practices were asked to compare and confirm the utility's position as reported by the project owner or developer. In addition, tariff information and copies of interconnection procedures and applications were requested. In some cases, there was no response from the utility. Thus, these case studies primarily represent the developers' views of the situations they encountered in seeking to interconnect these facilities. Therefore, the cases reported here may not reflect what might be a very different utility position with respect to some of the cases. (See additional discussion at introductory discussion of case studies.)

Throughout this document, "the utility" typically refers to the utility responsible for the distribution system with which the distributed generation installation sought to interconnect. This includes investor-owned utilities (IOUs), municipals, and cooperatives. In some cases, it may refer to a generation and transmission (G&T) utility that placed restrictions on the distribution utility.

Analyzing and Synthesizing Data

Finally, an attempt was made to summarize the barriers encountered in the case studies and demonstrate the real impact these barriers can have on a distributed power project. Section 2 includes the summary and analysis of the barriers represented in the case studies. Section 2.5 is an initial attempt at quantifying the barrier-related costs of interconnection. Section 2.6 presents findings and conclusions, including suggested actions for reducing barriers. Section 3 provides narrative descriptions of 26 of the individual case studies.

[1] The authors thank Joseph Galdo, Program Manager, Office of Power Technologies, and Richard DeBlasio and Gary Nakarado of the National Renewable Energy Laboratory for their leadership in setting up this study. Joe Iannucci of Distributed Utility Associates was the most notably included of several experts who played key roles in the conceptualization, organization, and review of this study. Our biggest thanks, however, go to the many projects developers, owners, and utilities who participated in the survey and follow-up interviews.

SURVEY FORM

Please Complete and Return ASAP To:

M. Monika Eldridge PE
Competitive Utility Strategies
meldridge@uswest.net
303/494-7397

1. CONTACT INFORMATION MUST BE PROVIDED!!

UTILITY, PROJECT DEVELOPER, AND CUSTOMER NAME WILL BE KEPT CONFIDENTIAL UPON REQUEST

CONFIDENTIALITY REQUESTED: _____ YES _____ NO

INTERVIEWER:
DATE of INTERVIEW:

CONTACT INFORMATION:
NAME:
ORGANIZATION NAME:
PHONE NUMBER(S):
EMAIL:
MAILING ADDRESS:

PROJECT NAME:

LOCATION / UTILITY or FRANCHISE:
[County Name]
[Utility Name]

TYPE OF RESOURCE /TECHNOLOGY TO BE INTERCONNECTED:

GENERATOR [SYNCHRONOUS, INDUCTION, INVERTER]:
RATED GENERATION CAPACITY (kW):
CAPACITY FACTOR or DUTY CYCLE:

INTENDED START DATE (month/year):

DATE PROJECT BROUGHT ON LINE (if project abandoned so indicate):

TYPE OF POWER APPLICATION (power quality, reliability, peak clipping, energy production, green market supply, CHP):

DESIGN/CONFIGURATION (on what site, connected to what facilities, to run under what conditions):

PROJECT OWNER (Residential Customer, Industrial, etc.):

END USE CUSTOMER(S):

POTENTIAL BENEFITS (renewable, onsite generation, etc.):

TYPE OF BARRIERS ENCOUNTERED:

1. Technical Interconnection
2. Interconnection Practices (delay, customized application etc)
3. Commodity Price (including monopoly buy-back rates)
4. Monopoly Distribution (including monopoly discounting, backup tariffs, uplift tariffs, and franchise rules)
5. Market Rules (size limits, transmission charges, ISO rules, ancillary service charges, scheduling, and loss imputation)
6. Competition Transition Charges
7. Local Permitting
8. Environmental Permitting
9. Other

PIVOTAL BARRIER:

DESCRIPTION OF PIVOTAL BARRIER:

OTHER BARRIERS:

COST TO OVERCOME THE BARRIER COMPARED TO COST OF PROJECT WITHOUT THE BARRIER:

ESTIMATED ECONOMIC LOSS TO SUPPLIER AND CUSTOMERS:

OTHER COMMENTS/CONCERNS, POSITIVE OR NEGATIVE:

LESSONS LEARNED and PROPOSED SOLUTIONS: (suggestions and ideas for the future)

REGULATORY JURISDICTION (State, Regional ISO, etc):
[Local]
[State]
[Federal]

CUSTOMER/INSTALLER CONTACT:

UTILITY/MUNICIPALITY CONTACT:

1.1 SUGGESTED OTHER CONTACTS FOR OTHER PROJECTS:

FOR INTERVIEWS WITH UTILITIES INVOLVED:

Utility Name:
Utility Contact Name:
Phone # (s):
email:
utility website: www.

Study Participants in the utility's service area:
CONFIDENTIAL:___ YES __ NOName:
CONFIDENTIAL:___ YES __ NOName:
CONFIDENTIAL:___ YES __ NOName:

Interviewer:
Date of interview:

_____Interconnect Agreement coming
_____All relevant tariffs coming
_____All original interview questions verified (UNLESS CONFIDENTIAL)

Notes:

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SECTION 2 SUMMARY AND ANALYSIS OF INTERCONNECTION BARRIERS

2.1 The Barriers Reported

Most of the distributed generation case studies experienced significant market entry barriers. Seven of the 65 projects did not experience significant barriers and reported uneventful and timely completion of the installation. Those less-typical examples of "barrier-free" development may provide instructive models for interconnection policy and practice that allow access to commercial markets for these technologies.

For purposes of this initial analysis, the barriers encountered in the case studies were classified into the following three types:

- ***Technical Barriers.*** Technical interconnection barriers include utility requirements intended to address engineering compatibility with the grid and grid operation. These barriers include specifications relating to power quality, dispatch, safety, reliability, metering, local distribution system operation, and control. Examples include engineering reviews, design criteria, engineering and feasibility studies, operating limits, and technical inspections required by distribution utilities. Technical barriers are described in Section 2.2.

- ***Business Practice Barriers.*** Business practice barriers relate to the contractual and procedural requirements for interconnection. Examples include contract length and complexity, contract terms and conditions, application fees, insurance and indemnification requirements, necessity for attorney involvement, identification of an authorized utility contact, consistency of requirements, operational requirements, timely response, and delays. Business practice barriers are described in Section 2.3.

- ***Regulatory Barriers.*** Regulatory barriers include matters of policy that fall within the jurisdiction of state utility regulatory commissions or the Federal Energy Regulatory Commission (FERC). These are issues that arise from or are governed by statutes, policies, tariffs, or regulatory filings by utilities, which are approved by the regulatory authority. Regulatory prohibition of interconnection, unreasonable backup and standby tariffs, local distribution system access pricing issues, transmission and distribution tariff constraints, independent system operators (ISO) requirements, exit fees, "anti-bypass" rate discounting, and environmental permitting were put into this category. Regulatory barriers are described in Section 2.4.

These categories of barriers are for convenience of description and analysis only. In other forums, these barriers have been classified in other ways. Quite often, the division is simply technical versus non-technical barriers. In many cases, the barrier described as being in one category could easily have been classified as being in another, because technical, regulatory and business issues are interrelated. Selection of a particular category was based on the perspective of the project owners or developers who were interviewed or on the judgment of the authors of this report.[2]

Figure 2-1 provides a comparison of the percentage of case studies effected by each category of barrier. A

[2] It could be argued that, at least in the case of regulated utilities, virtually all of the barriers that we have termed business practice barriers are regulatory, because the regulatory system has the jurisdictional authority to address the issues raised. The recent actions of state regulatory authorities in Texas and New York further blur the line of our distinction. They set forth the circumstances in which certain business practices may be utilized and prescribe the terms and forms of contracts. Many business practice issues nonetheless appear from these case studies to attract little regulatory attention. On the other hand, many of the regulatory issues or business practices are based on technical issues. In some cases, resolution of these technical issues may facilitate a regulatory solution or indicate that a particular business practice could be changed without detriment to the power system.

majority of reported cases encountered barriers in each of the three categories, with nearly two-thirds reporting business practice barriers and more than half reporting technical or regulatory barriers.

Given the anecdotal nature of these case studies and the relatively small sample of cases, no significance beyond the notional is intended with respect to the classification of barriers in one or the other of the three categories. However, any of the three categories of barriers can severely impact or kill a project. Consequently, any strategy to mitigate the barriers to distributed power that addresses only one or two of these will not be completely successful in opening markets to these technologies. A successful strategy must address all three: technical, regulatory and business practice barriers.

Table 2-1 indicates the severity of impact a category of barrier had on individual projects. It also shows that the issues are not limited to a few jurisdictions—18 states are represented in the case studies. The barriers also cut across technologies and can be important for 2-kW projects as well as for 20-MW projects.

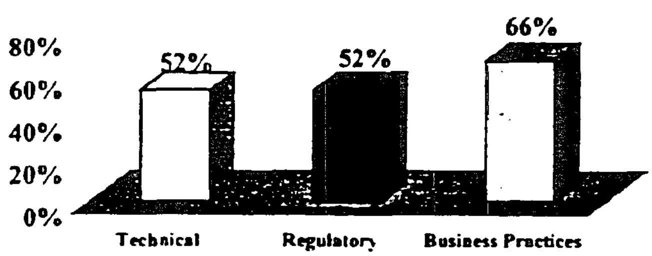
In response to what they believed to be unreasonable utility opposition to on-site power, one large commercial facility identified in this study chose to sever the connection with the grid altogether. Another project has no choice but to disconnect when its peak shaving generator is in operation. Others are still attempting to interconnect but may indeed decide to also operate independent of the utility system. They did not want to forgo the economic and reliability advantages of on-site combined heat and power facilities. These decisions followed long efforts to obtain optimal combined on-site and grid power arrangements. Some distributed power suppliers are finding it more economical to provide their own backup and standby generation on-site as well.[3]

2.2 Technical Barriers

Many of the technical barriers to distributed power relate to the utility's responsibility to maintain the reliability, safety, and power quality of the electric power system. Typical technical barriers encountered in the case studies are interconnection requirements that the utility may unnecessarily require to ensure reliability, safety, and power quality. These may include:

- Requirements for protective relays and transfer switches
- Power quality requirements
- Power flow studies and other engineering analyses.

Figure 2-1
Percent Projects Impacted by
All of Barriers Encountered



[3] Conversation with Murray W. Davis, P.E., Detroit Edison Co., March 24, 2000.

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Table 2-1. Barriers Encountered by All Case Studies

Case	Technology	Barriers		
		Technical	Regulatory	Business Practices
0.3-kW PV System in Pennsylvania - # 26	PV	○	○	●
0.820-kW PV System in Maryland	PV	○	○	⊘
0.9-kW PV System in New England - # 25	PV	⊘	○	⊘
2-kW PV System in California	PV	⊘	○	⊘
2-kW PV System in New York	PV	⊘	●	⊘
2.4-kW PV System in New Hampshire	PV	⊘	⊘	⊘
3-kW PV System in California - # 24	PV	⊘	○	⊘
3-kW PV System in New England - # 23	PV	⊘	○	⊘
3.3-kW Wind/PV System in Arizona	PV/W	⊘	⊘	⊘
7.5-kW PV and Propane System in California	NG	⊘	○	⊘
10-kW PV System in California - # 22	PV	○	○	○
10-kW Wind Turbine in Oklahoma (A)	W	○	○	○
10-kW Wind Turbine in Oklahoma (B)	W	⊘	⊘	⊘
10-kW Wind Turbine in Texas	W	⊘	⊘	⊘
10-kW Wind Turbine in Illinois	W	⊘	○	⊘
12-kW PV System in California	PV	○	○	⊘
17.5-kW Wind Turbine in Illinois - # 21	W	⊘	⊘	⊘
20-kW Wind/PV System in Midwest - # 20	PV/W	⊘	⊘	⊘
20-kW Wind Turbines in Minnesota	W	○	○	○
25-kW PV System in Mid-Atlantic Region - # 19	PV	○	○	⊘
35-kW Wind Turbine in the Midwest - # 18	W	⊘	○	⊘
37-kW Gas Turbine in California	NG	⊘	⊘	⊘
43-kW Commercial PV System in Pennsylvania	PV	○	○	●
50-kW- Gas Turbine System in Colorado	NG	○	○	⊘
50-kW Cogeneration System in New England	CG	●	○	⊘
40 sites of 60-kW NG IC Systems in California	NG	⊘	⊘	⊘
75-kW NG Microturbine in California - # 15	NG	⊘	●	⊘
90-kW Wind Turbine in Iowa	W	⊘	⊘	⊘
100-kW Hydro Pump in Colorado	HY	○	⊘	○
120-kW Reciprocating Engine for Hospital - # 14	P	⊘	○	⊘
130-kW Wind Turbines in Pennsylvania	W	○	⊘	⊘
132-kW PV System in California	PV	⊘	⊘	⊘

Key to Symbols:
- Project was stopped or prohibited from interconnection because of barrier ●
- Project was delayed or more costly because of barrier ⊘
- Project was not hindered because of barrier ○

CG= Cogeneration, NG= Natural Gas, HY= Hydro Pump, IC=Internal Combustion, PV=Photovoltaic Solar, W=Wind, FC = Fuel Cell, P = Propane, D = Diesel.

Case	Technology	Barriers		
		Technical	Regulatory	Business Practices
140-kW NG IC System in Colorado - # 12	NG	⊘	○	⊘
200-kW Fuel Cell System in Michigan - # 11	FC	○	⊘	⊘
260-kW BG Microturbines in Louisiana - # 10	NG	○	●	●
300-kW Commercial PV System in Pennsylvania - # 17	PV	○	○	●
0.050-kW to 500-kW Wind and PV in Texas - # 16	PV/W	○	○	○
500-kW IC NG System in New York	NG	○	●	○
500-kW Cogeneration System in New England	CG	●	○	⊘
560-kW Cogeneration System in New York	CG	⊘	⊘	⊘
600-kW Wind Turbines in Minnesota	W	○	○	○
Seven sites- 650-kW IC NG System in New England	NG	⊘	●	○
703-kW Steam Turbine in Maryland - # 9	CG	⊘	○	⊘
1-MW Diesel IC Generator in Colorado - # 8	D	○	⊘	●
1-MW Landfill NG IC System in Massachusetts - # 7	NG	○	●	○
1.2-MW NG Turbine in Texas - # 6	NG	○	⊘	⊘
1.2-MW Cogeneration System in Illinois	CG	⊘	⊘	⊘
1.2-MW Cogeneration System in Ohio	CG	○	○	○
1.650-MW NG IC System in Illinois	NG	○	○	⊘
1.925-MW Wastewater Cogeneration System in Colorado	NG	⊘	⊘	⊘
2-MW Diesel System in Colorado	D	⊘	⊘	⊘
2.1-MW Wind Turbines in California	W	⊘	○	⊘
3 to 4-MW NG IC System in Kansas	NG	○	⊘	○
5-MW Hospital Cogeneration System in New York - # 5	CG	⊘	●	○
5-MW Waste to Energy System in Colorado	NG	○	○	⊘
5-MW Cogeneration System in New England	CG	○	⊘	○
8-MW Cogeneration System in New England	CG	○	⊘	○
10-MW Industrial Cogeneration System in New York - # 4	CG	○	●	○
12-MW Cogeneration System in New Jersey	CG	⊘	⊘	○
15-MW Cogeneration System in Missouri - # 3	CG	⊘	○	⊘
21-MW NG Cogeneration System in Texas - # 2	CG	○	⊘	⊘
23-MW Wind Turbines in Minnesota	W	○	○	○
25-MW Cogeneration System in New England	CG	⊘	⊘	○
26-MW Gas Turbine in Louisiana - # 1	NG	○	●	○
56-MW Waste to Energy System in New England	NG	○	○	⊘

Key to Symbols: Project was stopped or prohibited from interconnection because of barrier ●
Project was delayed or more costly because of barrier ⊘
Project was not hindered because of barrier ○

CG= Cogeneration, NG= Natural Gas, HY= Hydro Pump, IC=Internal Combustion, PV=Photovoltaic Solar, W=Wind, FC = Fuel Cell, P = Propane, D = Diesel.

Safety Standards

The principal safety concern among utilities with respect to connecting generation equipment to the grid is protection against "islanding," the condition where a generating facility continues to supply power to a portion of the grid when the balance of grid has been de-energized (during a power outage, for example).[4] This condition is of concern in two scenarios: where the distributed generator is either "feeding a short circuit" thus potentially causing a fire, and where a lineman might mistakenly come in contact with what is otherwise thought to be a de-energized line.

Traditionally, utilities protected against islanding by using mechanical relays and transfer switches that automatically isolated generating facilities from the grid, whether these facilities were utility-owned or non-utility owned. This equipment is effective and reasonably efficient, but is prohibitively expensive for small-scale distributed generators.

However, continuing innovations in power electronics have resulted in the development of relatively inexpensive electronic circuitry that provides effective anti-islanding protection. The traditional protective relays and other anti-islanding equipment were separately engineered and installed at a substantial cost to the generator. The newer electronic circuitry can be integrated into inverter components of the distributed generating facility at substantially lower cost. This circuitry can be programmed to shut down when there is no line voltage detected from the utility. This new equipment has been operating for more than a decade (particularly in PV applications) without any reports of islanding-related problems.[5] Moreover, Underwriters Laboratories (UL) has developed and approved a functional test for the anti-islanding circuitry for the inverter technology used in small photovoltaic and wind energy applications. The UL is also expected to develop comparable standards for all distributed generating technologies in coming years, as part of a parallel effort with the Institute of Electrical and Electronics Engineers (IEEE) to develop interconnection standards for the broader category of distributed generators. Developers have suggested that there is a need to develop modeling tools and educational material for utility distribution to engineers so that they can expedite their review of these issues.

Nevertheless, a number of the case studies indicate that utilities remain reluctant to accept the protection circuitry built into the distributed generating facilities as an alternative to separate protective relays and other anti-islanding equipment. For example, the owner of a 0.9-kW PV system in New Hampshire was required by the utility to install separate protective relays even though the PV system's inverter included over/under voltage and over/under frequency protection, as well as anti-islanding protection. According to this distributed generator, the utility's justification was that it was unfamiliar with the inverter and preferred to use equipment with which it was more comfortable. The installation of the relays, however, cost the customer $600 (approximately $660/kW) and increased the cost of the system by approximately eight percent. In addition, the utility required the customer to have the relays calibrated annually, imposing a recurring cost of $125 per year that offsets nearly 65 percent of the annual energy output from the PV system.[6]

Another case involved 140-kW reciprocating-natural-gas-engine-generators installed in Colorado. The utility required a multi-function solid-state relay package that cost the project developer an additional $3,000 for relays, which were redundant to those

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[4] As distributed power technologies have begun to make community-scale systems technically and economically feasible, the advantages and enhanced reliability of islanding are beginning to be explored. Keeping a community or facility's lights on, when neighboring communities or facilities are out is not only an economic advantage but a public health and safety advantage as well. Nonetheless, utilities often continue to view the potential for energizing an otherwise de-energized line as a safety risk to line workers, the public and property. The risk, as stated, is that a person could come into contact with a utility line thinking it is de-energized when it is not.

[5] Personal communication with John J. Bzura, Ph.D., P.E., Principal Engineer, Retail Engineering Department, New England Power Service Company, on February 10, 2000. Dr. Bzura has managed New England Electric Photovoltaic Research and Demonstration Projects since 1987.

[6] Case #25.

already included in the multi-function interconnection package installed.[7]

Other case study respondents reported similar problems with protective relay requirements that appeared redundant to the distributed power developers, given the protection functions built into the generating facilities. For instance, the developers of a 132-kW photovoltaic system in Northern California reported that the interconnecting utility initially requested a separate package of pre-qualified or tested protective relays costing between $25,000 and $35,000, even though the inverters installed with the system incorporated the protective functions that the utility wanted. The utility eventually dropped this requirement.[8]

Another aspect of utility safety is a frequent requirement that a utility perform its own tests on equipment with which it has no experience. This separate utility testing requirement can add significant cost and delay to a project, especially from the vendors viewpoint. Vendors see each separate utility performing similar tests as an unnecessary major barrier and would like to see prequalification or certification procedures established.

Power Quality Standards

Power quality concerns include voltage and frequency disturbances, voltage flicker, and waveform distortion. Distributed power facilities, like central-station facilities, can have either a detrimental or a beneficial effect on power quality.

As with the modern electronic approaches that can provide islanding protection, innovation in power electronics is revolutionizing the way that power quality concerns are addressed. Traditionally, utilities required the installation of over/under voltage and over/under frequency relays and other, separate, protective devices to ensure that power quality requirements were being met. Today, many distributed generators have built-in functionality that meets the most stringent of power quality requirements. For example, IEEE Standard 519-1992, entitled "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems," has become the reference standard with respect to power quality concerns. This is the standard to which inverter manufacturers generally design their products.

The principal problem facing distributed generators with respect to power quality issues is the same as with anti-islanding protection. Lacking experience with the newer technologies or standardized testing procedures, utilities so far have been reluctant to accept the power quality protection built into distributed generating facilities. Instead, they have sought to require the use of traditional, utility-approved equipment instead.

Local Distribution System Capacity Constraints

The general approach among utilities in dealing with local distribution system capacity constraints is to conduct pre-interconnection studies before interconnecting distributed generators. These studies evaluate the potential effects of the distributed generating facility on the specific portion of utility system to be affected, and determine whether any upgrades or other changes are needed to accommodate the generating facility. The cost of these studies usually is passed on to the distributed generator. This practice is often blessed by the regulatory bodies under the "user pays" principle. However, equivalent studies for new loads that may be of equal size and impact on facilities may be addressed quite differently under long-established service tariffs.[9]

[7] Case #12.
[8] Case #13.

[9] Distribution system engineering has been referred to as an "art, not a science." While not all engineers would agree, there is agreement that there are many more variables in distribution engineering than designing transmission. This complexity can lead to a variety of solutions by utilities, thus making standardization of distributed utility solutions more difficult.

The following case histories identified the cost and delay of pre-interconnection studies as a significant barrier to interconnection of their distributed generating facilities:

- A 0.9-kW PV system in New Hampshire that paid $600 for an interconnection study ($667/kW)[10]
- A 3-kW PV system in New Hampshire where the customer refused to pay $1,000 for an interconnection study ($333/kW)[11]
- A 703-kW cogeneration facility in Maryland where the customer paid $40,000 and lost several months of project time to design engineering review standards subsequently abandoned by the utility.[12]

New York and Texas recently addressed the conflict between a utility's interest in conducting interconnection studies and a distributed generator's interest in limiting the scope and cost of such studies. These two states, however, have taken different approaches.

In New York, the Public Service Commission adopted a rule on December 31, 1999,[13] that states that interconnection studies shall not be required for facilities under 10-kW. Also, studies may not be required for facilities up to 50-kW interconnected on a single-phase line, or up to 150-kW on a three-phase line. Beyond these limits, an interconnection study is required, and the full cost of any study is passed through to the distributed generator.

On December 1, 1999,[14] the Texas Public Utility Commission adopted a rule that is more flexible and accommodating to utilities and distributed generators. The Texas proposal stated that a utility *may* conduct a study before interconnecting *any* facility. However, Texas prohibits a utility from charging certain distributed generators for the cost of the study, including the following:

- Distributed power facilities that will not or do not export power to the utility system, regardless of size
- Individual single-phase distributed power units exporting less than 50-kW to the utility system on a single transformer
- Individual three-phase units exporting not more than 150-kW to the utility system on a single transformer
- Pre-certified distributed power units (as defined in the rule) up to 500-kW that export not more than 15 percent of the minimum total load on a single radial feeder and also contribute not more than 25 percent of the maximum potential short circuit current on a single radial feeder.

Developers or owners of distributed generating facilities not qualifying for one or more of these exemptions may be charged for the costs to conduct an interconnection study.

The Texas rule also establishes certain performance-related standards for a utility in cases where an interconnection study is required, as follows:

Time Limit. The conduct of such pre-interconnection study shall take no more than four weeks.

Written Findings Required. A utility shall prepare written reports of the study findings and make them available to the customer.

Consideration of Costs and Benefits to System Required. The study shall consider both the costs incurred and the benefits realized as a result of the interconnection of distributed power to the company's utility system.

Estimate of Study Cost Required. The customer shall receive an estimate of the study cost before the utility initiates the study.

[10] Case #25.
[11] Case #23.
[12] Case #9.
[13] State of New York Public Service Commission, Opinion No. 99-13, Case No. 94-E-0952 – In the Matter of Competitive Opportunities Regarding Electric Service, filed in C 93-M-0229, Opinion and Order Adopting Standard Interconnection Requirements for Distributed Generation Units, Issued and Effective: December 31, 1999. http://www.dps.state.ny.us/fileroom/doc7024.pdf.
[14] See http://www.puc.state.tx.us/rules/rulemake/21220/21220.cfm.

2.3 Business Practice Barriers

Business practices for these purposes include the contractual and procedural requirements imposed by the utility before it allows interconnection. Although all such business practices are, in principle, subject to regulatory authority, there appears to be little regulatory attention so far to business practices that are discouraging distributed generators.

Business practices create artificial barriers when they impose terms, costs, or delays that are unnecessary for purposes of safety and reliability, and are inconsistent with the underlying economics or other drivers of the distributed generation project. Many of the distributed generation developers that were interviewed believe that some utilities use unreasonable terms, excessive costs, and inappropriate delays to either gain utility advantage or impede the market for distributed power. The practices that most often create barriers center around the following:

- Initial utility contact and requests for interconnection
- Application and interconnection fees
- Insurance and indemnification requirements
- Utility operational requirements
- Final interconnection requirements and procedures.

The case studies reveal utility business practices that vary from utilities that promote distributed power under cooperative arrangements[15] to those that actively oppose the entry of distributed power, including flat prohibition. As with the other categories of barriers, instances where the business practices of the utility resulted in projects where interconnection went smoothly provide a useful contrast to cases where substantial barriers were present. Such utilities value distributed power as a resource, particularly during peak demand periods, or see streamlined interconnection as a potential future market opportunity for them.

[15] For a description of a utility that has embraced and encouraged distributed generation see discussion of model peak shaving practices of Orange and Rockland on page 16.

One wind energy customer called the local utility only twice, once at the initiation of the project to give notice of intent to connect and once at the conclusion in order to begin generation. The utility began net billing without further requirements.[16] In California, the requirements for interconnecting small PV systems under the state's net metering law have now become standardized to the point where most customers report no interconnection-related conflicts with their utilities.[17] One common element associated with projects where distributed generation developers were more satisfied with their business dealings with the utilities was the designation by the utility of a specific contact person to review necessary requirements and assist in procedures.

Interviews with project owners and developers suggest, however, that some utilities generally oppose interconnection of distributed power, with varying explanations. Some utility representatives told customers that interconnection was not possible. In some cases, utilities knowingly or unknowingly chose not to follow state commission regulations, forcing the customer to pursue legal remedies. In one case, a municipal utility initially refused to buy back power from a facility because the city claimed it was not regulated by the Federal Energy Regulatory Commission (FERC) and not subject to the Public Utility Regulatory Policies Act (PURPA). The state utility commission eventually held that the city was subject to PURPA.[18] In another case, the utility interpreted PURPA as requiring only Qualifying Facilities (QF) distributed generation to be connected to the distribution system. After long negotiations, the utility stated that it would make an exception to allow interconnection of non-QF generation in that specific case.[19]

In other cases, utilities appeared to suffer more from a lack of experience and an absence of established procedures for addressing interconnection of distributed generators than intent to create barriers. In many of the case studies, the utilities did not have a designated department to deal with interconnection issues and could not provide the necessary guidance. As one project developer stated, "the utility didn't

[16] 10-kW Wind Turbine in Oklahoma (A)
[17] Case #22.
[18] 10-kW Wind Turbine in Oklahoma (B)
[19] 10-kW Wind Turbine in Texas.

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understand the project benefits, though several people there did support the project. They did not understand how to build and connect this system, and they would not take the leadership role to coordinate project fulfillment." (Note that some developers believe that not all vendors have provided enough support to utilities and developers in this area.) This developer experienced significant delays completing the interconnection process.[20] In some smaller installations, owners were able to install the project on the customer side of the meter without notifying the utility, so as to avoid the delays and costs associated with the interconnection process.

Encouragingly, many utilities are demonstrating progress toward more expedient procedures for handling interconnection on a routine basis. Mostly this is in response to clear obligations to connect and more frequent requests for interconnection as has occurred in some states for smaller-scale systems under net metering laws.

Initial Contact and Requests

Case studies where interconnection was completed in a commercially reasonable time frame benefited from a consistent point of contact and a prompt response time. Judging from the case studies, such "best practice" is not the usual procedure among many utilities. Reaching the appropriate utility representative and getting a consistent response was frequently cited as a significant problem for both small- and mid-sized projects. With large projects, developers usually included these costs as a "part of doing business with utilities" and could more easily bear the cost of lengthy contested legal negotiations. Many distributed power facilities could not. Most often cited problems included the following:

- Application process delays
- Unproductive time spent by individuals and developers
- Excessive procedural requirements.

Application and Interconnection Fees

Application and interconnection fees are generally required for the approval or permitting of distributed power facilities. These fees are typically assessed regardless of size of the proposed project. Therefore, they present a significant market barrier for smaller-scale facilities.

In one case, the utility initially requested an "installation fee" of $776.80 for a 3-kW PV system or $259/kW. The customer contacted the state energy office for assistance, after which the utility's response changed. Approximately 15 days after payment of the fee, the utility returned the check stating that no "meter installation fee" was required. Contrary to the initial response, the customer's existing meter was bi-directional and therefore was capable of net metering the facility.[21]

Some of the smallest distributed generators are asked to pay fees or charges equivalent to many months—or even years—worth of anticipated energy savings. For instance, in one case the owner of a 250-Watt "AC Module" photovoltaic system faced up to $400 in interconnection fees, which added $1,600/kW to the project costs and was equivalent to approximately ten years of energy savings from the system.[22]

Insurance and Indemnification Requirements

Insurance requirements are a particularly troubling issue for small distributed power facilities. Small distributed generators argue that the risks from facilities that use UL listed equipment and are installed in accordance with IEEE and other applicable standards are minimal, and comparable to electrical appliances and other equipment that are routinely interconnected without special requirements. Moreover, these distributed generators argue that in the unlikely event of an accident, existing laws are adequate to allocate liability among potentially responsible parties. Utilities argue that as "deep pockets," they are likely to be brought into any claim attributed to the operation of a customer-owned distributed generating facility. They add that generators pose increased risk compared to appliance and electric loads. On these grounds, they demand insurance and indemnification naming them as payee.

[20] 2-MW Diesel System in Colorado.

[21] Case #24.

[22] Case #26.

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Insurance requirements are often high in relation to the project cost, particularly compared to standard commercial practice with other products. One utility required $1 million in worker's compensation insurance coverage and $5 million in commercial general liability insurance coverage for the parallel interconnection of any non-utility generating source.

A 12-kW solar photovoltaic demonstration system in Florida (not a case study) was forced to shut down when the utility imposed a $1 million liability insurance requirement. The utility had claimed that the cost for required coverage would be in the range of $500 to $1,000. The facility owner received quotes for this coverage of $6,200 per year, however, and shut down the project because of this.

In response to this issue of liability insurance requirements, at least five states have prohibited utilities from imposing liability insurance requirements on small-scale distributed power facilities. In at least four other states, utility regulatory commissions have reduced insurance requirements from the $500,000 to $2,000,000 range requested by utilities to $100,000 to $300,000, depending on the state and the type of facility.[23] In New York, for example, the Public Service Commission rejected the utilities' proposed insurance requirements for small-scale PV systems, after concluding that the proposed requirements were "clearly burdensome and overly costly," and noting that one utility's proposed requirements "are practically impossible for residential customers to meet."[24] The New York Commission instead allowed utilities to require customers to demonstrate that they are carrying at least $100,000 in liability coverage through their existing homeowner's policies.

Utility Operational Requirements

Operational requirements imposed by utilities also can make distributed power applications uneconomical. In one case, a distributed generating facility operating in a network distribution system[25] was required by the utility to shut down if one of the network feeders went down. This operational requirement was contrary to the distributed generation facility's purpose of optimizing energy production and increasing reliability for the customer, and unexpected in light of the technical modifications and safety equipment the vendor agreed to install to operate as intended.[26]

In another case, the utility required the facility to reduce its output to below the customer's loads served by the distributed power facility. Because the facility must limit its generation to ensure that it does not export energy to the utility, this also prevents any export of excess power to other customers. The distributed generation developer was told that the utility was concerned with preserving loads for the utility's own baseload generating plants. This utility-imposed limitation eliminated any access to wholesale power markets for the distributed power facility. This operating constraint in turn cut off the economic and system benefits that might result from delivery into those markets during times of peak demand, or to meet specialized demand, as might arise for renewable energy, in those markets.[27]

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[23] The five states that have prohibited additional insurance requirements are California, Maryland, Nevada, Oregon, and Virginia. In Idaho, a utility-proposed $1 million insurance requirement was reduced by the PUC to $100,000. In New York, utility-proposed requirements of $500,000 to $1 million were reduced by the PSC to $100,000. In Vermont, utility-proposed requirements of $500,000 were reduced by the PSB to $100,000 for residential customers' systems and $300,000 for commercial customers' systems. Finally, in Washington, utility-proposed requirements of $2 million were reduced by the UTC to $200,000. See Response of the American Solar Energy Society, American Wind Energy Association, Interstate Renewable Energy Council, Solar Energy Industries Association, and Maryland-DC-Virginia Solar Energy Industries Association to the Request for Information from the Virginia Corporation Commission (August 30, 1999), on file with the Virginia Corporation Commission.

[24] New York Public Service Commission, Order on Net Metering of Residential Photovoltaic Generation (Feb. 11, 1998).

[25] In contrast to a radial-feed distribution system, a network distribution system accommodates multiple sources feeding a honeycomb grid with multiple paths and feeder lines into any one location. The multiple flow paths from any particular source to any particular load can be more complex on these systems, but the reliability impact of losing any one line can also be less severe.

[26] Case #9.

[27] 1.2-MW Cogenerating System in Illinois.

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In some cases, the utility asserted complete control over operation of equipment for the stated purpose of shutting down the facility for planned and unplanned outages[28] of the utility system. In other cases, utilities imposed control requirements out of safety considerations or for maintaining distribution system stability. However, as discussed above, vendors claim that most of today's distributed power equipment is designed to manage these legitimate safety needs. In most cases, discontinuing parallel operation during emergencies and other abnormal operating conditions can be easily handled through technical and contractual requirements without turning over complete operational control of the distributed power facility. Again, although utility operational control might have been acceptable for the much-larger PURPA facilities, it is often unacceptable for distributed power facilities, where customer objectives include the provision of backup or emergency power or sales into real-time power markets.

In one instance where the utility needed the customer-owned, on-site, generation to reduce system peaks to meet the utility's supply needs, the customer was nonetheless prohibited from peak shaving to reduce its own bill. The utility required exclusive control of the operation of the equipment, which allowed it to start the generator to meet utility requirements, while preventing the customer from doing so. In another case, the customer was allowed to curtail load during peak periods to reduce its bill, but not permitted to operate back up generation to continue operation during peak periods. The facility had a backup generator that it was willing to operate, but the utility would not allow operation.[29]

Utilities also have procedural requirements appropriate for some, but not all, distributed power facilities. For example, one utility requires distributed facilities to maintain an operational log. Many utilities require a generator to notify the utility before bringing the facility on line. The utility may require the facility to delay synchronizing when the utility is experiencing line trouble or system disturbances.

[28] Planned outages occur for purposes such as maintaining lines; testing relays; rearranging, modifying, or constructing lines; and maintaining lines or station equipment.

[29] Case #8.

Some of these requirements, originally developed (and intended) for larger facilities, are inappropriate for smaller facilities that are indistinguishable from normal load variations during the course of system operation. In fact, some utilities do exempt smaller facilities.

Final Interconnection Delay

Proponents of several projects reported delays continuing from the application process through final approval. In some cases these delays were procedural; in other cases, delays were equipment-related on the utility side. One utility postponed transmission connection on questions of system reliability for several months during the early high demand summer months, then reversed its position as the summer peak approached and the probability arose of capacity shortages.[30] In another case, a utility entered a contract with a project owner allowing for interconnection if the project met certain criteria. After the project met the requirements and testing of the facility was complete, the utility stated that the facility could not interconnect at the time.[31]

Project Delays

As reported by project developers and customers, the total process from initially contacting the utility to obtaining final approval could be a lengthy one. In 17 of the 65 cases, no delay was reported and the project was operational as scheduled. Twenty five of the 65 projects experienced some delay. In three cases, the projects did eventually go forward even though the delay was considerably greater than two years. Figure 2-2 shows the actual reported delay in number of months beyond planned interconnection. Note that for 23 projects interviewers were not able to state definitely if a delay occurred or not; so only 42 cases are reported in this figure.

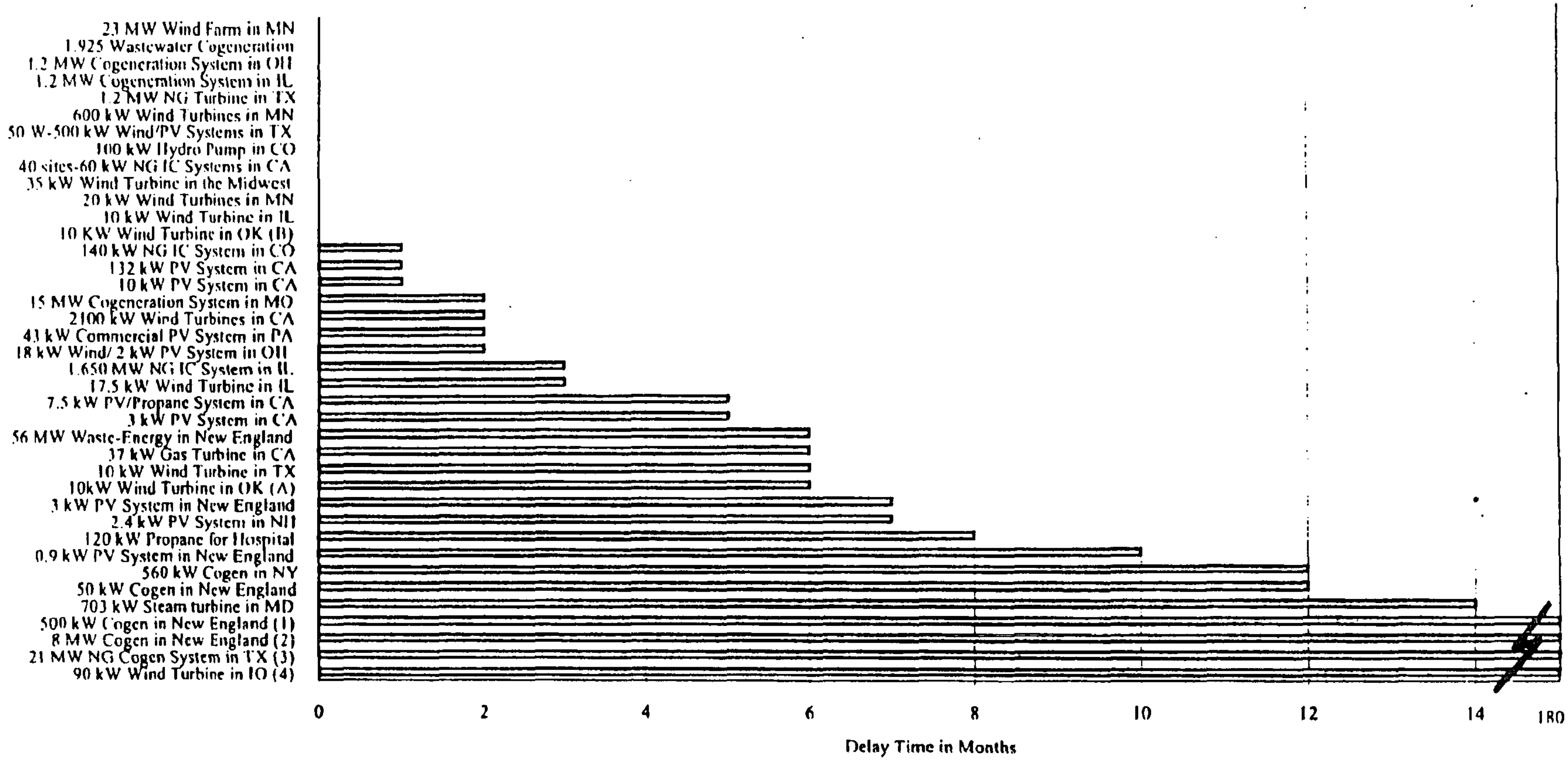
Other Business Practice Barriers

Utilities continue to maintain monopoly control of the distribution system to which distributed power projects must interconnect. Although their relationships with distributed generators are subject to regulatory scrutiny, as discussed above, utilities

[30] Case #3.

[31] 500-kW Cogeneration System in New York.

Figure 2-2
Project Delays Attributed to Interconnection Issues



1) The 500-kW cogeneration project in New England is installed but it has not yet been interconnected. The project has been delayed for 24 months to date. In the fall of 1999, negotiations with the utility were still ongoing.

(2) The 8-MW cogeneration project in New England was to replace old boilers in a factory that burned down. The customer sought to install the cogeneration system in the early 1990's, but was not able to get the project installed until November 1999. Even though the project replaced a previously existing system with more-polluted boilers, the air board would not provide emissions credits. The air board wanted 99% improvement, not just 90%. After six years of negotiation, the air board finally approved the new system and provided the needed air credits. The new combustors use standard SOLONOX technology to reduce emissions to 15 ppm NO_x and operating records show the system can achieve less than 10 ppm.

(3) The 21-MW Cogeneration project in Texas was actually delayed for 10 years. The original start date was 1989 and the project was operational in September of 1999. The utility offered the customer lower rates each time the developer provided lower bids to the customer. Finally, the developer was able to offer a package that was competitive and the project went forward.

(4) This project was actually delayed for 15 years. When the customer approached the utility in 1984 requesting to interconnect, the utility sent the customer a 68-page contract. Since that time, the customer has been attempting to interconnect and has started operating the wind turbine off the grid. The customer is still negotiating with the utility in an attempt to interconnect.

have traditionally been given a great deal of discretion in setting the interconnection framework for distributed power projects. As shown by the PURPA experience, they can use that discretion to discourage or prevent customers from interconnecting to "their" grid. Distributed power projects have the same vulnerabilities as the much larger projects covered by PURPA, but with markedly smaller economic margins to overcome the barriers. One of the most troublesome examples from a public policy point of view—selectively discounting tariffs to undercut prices offered by a distributed power project—is discussed under regulatory barriers in Section 2.4 on page 27.

Customer or Distribution-Level Peak Shaving

Distributed generation can provide capacity to meet energy needs during peak periods, either for a customer or for a local utility. This "peak shaving" can reduce demand charges from the supplier, which rise with peak demand. Particularly when coupled with on-site benefits like emergency backup, or combined heat and power, this use of local generation offers significant economic advantages. Not surprisingly, there were several cases in which large utility customers, or local utilities purchasing from generation and transmission (G&T) wholesale suppliers, sought to employ distributed generation to reduce energy costs and secure other local benefits.

The use of distributed capacity as an alternative to constrained transmission capacity, by a utility not involved in any of our case studies, stands in stark contrast to utility response in other cases. The Orange and Rockland Utilities, Inc., now a subsidiary of New York's Consolidated Edison, Inc., used a capacity payment tariff to recognize the value of distributed capacity in meeting system shortages. This specifically designed tariff established deaveraged capacity payments payable during summer months at specified locations to secure additional needed capacity during peak months. The utility reported the tariff worked effectively for more than ten years to supply needed capacity in the outlying portion of the service territory. Over the ten years, capacity payments ranged from \$3/kW-month to \$11/kW-month for the four summer months. The higher capacity payments brought on capacity in a transmission-constrained area for many years. The ease of implementation and effectiveness of the Orange and Rockland capacity tariff reveals the potential of the untapped distributed power market and the widespread absence of any regulatory principles governing its emergence. For instance, the United Kingdom uses a demand credit to encourage generation in areas where transmission congestion is a recurring problem.

Where existing tariff structures have encouraged or allowed customers to use distributed power investments to mitigate peak demand charges, some utilities sought to modify the tariffs to prevent customers from capturing these savings. Or, a shift to high peak demand charges on the standby service was used to shift the equivalent revenue recovery to the backup peak demand. In one case, the utility shifted peak demand charges from the full service tariff to the standby tariff to capture additional revenues from the distributed generator. This standby-penalty approach was largely responsible for those cases in which commercial customers disconnected from the utility system altogether by providing both regular and standby energy service from distributed power facilities.

These cases with seemingly arbitrary and conflicting treatment of similar distributed power installations indicate the absence of coherent, consistent tariff principles governing the use of peak demand and backup demand charges. In many cases, these charges defined the market comparison between distributed power facilities and distribution utilities. Although multiple case studies provide examples of utilities using these charges to discourage distributed power, cases such as the Orange and Rockland utility using peak demand charges to encourage distributed power are rare. We found no record of utility regulators focusing on the relationship between such charges and their effects on the development of distributed power. Proceedings in California and New York, however, are looking at the underlying cost and tariff issues and may begin to address these potentially market-defining principles.

Several case study respondents also noted the marked difference between how a utility accustomed to a regulated monopoly approaches its projects and how a competitive business must approach its projects. For example, one utility objected to scheduling overtime or additional contracting expense to meet an interconnection deadline even when the developer offered to pay for the costs. Conversely, vendors in several instances claimed that the utility was using 'gold plating' practices, in which unnecessarily costly mandates were imposed. In one instance, the utility proposed a three million dollar substation instead of co-location and interconnection at the existing substation.[32] In other cases the utility contractually limited the project's ability to sell back to the grid.[33] These "cultural" differences between traditional regulated utility practice and competitive practice were cited as barriers in several cases.

In the case cited above, the substation interconnection requested by the developer would have offered direct distribution access to industrial and urban customers in a future restructured market, without additional transmission line reservation and fees. As ultimately configured by the utility, the interconnection enters at the transmission system and eliminates direct distribution access.[34]

Negotiable Charges

We define negotiable charges to include instances where the utility initially quoted fees, tariffs, equipment, or testing, but dropped these charges or demands after negotiation or pursuit of legal remedies. Because the cost of pursuing legal remedies is very high, the cost of challenging proposed charges impose a substantial cost for distributed generators, even if they prevail in having the fees and charges dismissed. More often, these charges simply stop projects or force the very small projects to proceed as "pirates," operating without notifying the utility. Case study respondents in all size categories reported having to confront such charges, and in several cases the cost of effectively challenging the charges simply led to abandonment of the project.

[32] Case #3.

[33] 1.2-MW Cogeneration System in Illinois

[34] Case #3.

The assessment of charges that later were abandoned was particularly prevalent with small customers (60-kW or less). In fact, among the case studies, one-third of small customers were presented with charges that they ultimately did not pay. Charges initially sought by the utility were dropped or reduced in at least ten cases, as shown in Table 2-2. This high incidence of rescinded demands for smaller customers may result from such customers being more adamant about not paying extraordinary fees. Or, such assessments may have proven particularly effective in discouraging grid connection. In any case, the burden of the charges the utilities originally demanded relative to total project costs is much higher in residential and small commercial cases, which may account for these owners reporting these charges as extraordinary or unreasonable for the project size. Unfortunately for smaller sized generation facilities, however, there are genuine safety concerns even for small projects.

2.4 Regulatory Barriers

Seven projects documented in this study were abandoned or are still pending with little hope of completion due to regulatory barriers. The barriers included outright prohibition; what appeared to the distributed power developers as arbitrary tariff rates for access and backup power; and selective discount pricing designed to discourage customer use of distributed power. Case-by-case procedural review and legal remedies, where they exist, are not so much the solution as just a final barrier where the scale of the project can justify no effort beyond a simple and inexpensive way of asserting those rights.

The case studies document the following types of regulatory barriers:

- Direct utility prohibition
- Tariff barriers
  - Demand charges and backup tariffs
  - Buy-back rates
  - Exit fees
  - Uplift tariffs
  - Regional transmission procedures and costs
- Selective discounting
- Environmental permitting.

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Table 2-2
Negotiable Charges

Case	Charges
10-kW Wind Turbine in Texas	Equipment requirements for metering, transformers, and relays were initially assessed but eventually dropped. The utility originally refused to buy back any power and eventually purchased power back at S1.5 cents/-kWh (avoided cost).
10-kW Wind Turbine in Oklahoma	The customer was initially asked to pay for unnecessary metering and an isolation transformer. This requirement was eliminated after six months. In addition, the initial demand for a one-million-dollar liability insurance policy was relaxed.
2.4-kW PV System in New Hampshire	The utility initially asked for a S250,000 comprehensive general liability policy and S1,000 for a site. The insurance demand was reduced to a certificate of insurance, and the site inspection fee was ultimately dropped.
20-kW Hybrid Wind/PV System in Midwest	The utility initially requested the project owner to pay for the power pole, meter, and transformer for a new house he was building because of the renewable energy installation. The utility backed down after being reminded that they would not have asked a regular customer to pay for this basic initial hardware installation.
17.5-kW Wind Turbine in Illinois	The utility initially requested expensive manual and automatic disconnects, synchronizing relays, voltage transformers, over/under voltage relays, and over/under frequency relays. Most of these demands disappeared after the wind turbine supplier spoke with the utility.
7.5-kW PV and Propane System in California	The customer disputed interconnection fees of S776.80 but eventually paid in order to facilitate progress. The customer contacted the CEC for assistance and, as a result of the CEC's efforts, the utility returned the payment of fees.
40 Sites of 60-kW NG IC Systems in California	The equipment supplier successfully challenged standby and demand charges imposed by two separate utilities, so no charges were ultimately applied.
120-kW Propane Gas Reciprocating Engine For Hospital	The utility requested a S40,000 redundant circuit breaker—that was no longer being manufactured because it was only used where extremely high-quality grade equipment with reliability ratings are required such as nuclear facilities. The utility also sought standby charges of S1,200/kW/year that were disapproved by the PUC.
140-kW Natural-Gas Fired Reciprocating Engines in Colorado	The utility initially asked for an extra S23,000 worth of equipment for power factor correction and neutral circuit protection out rescinded the request after negotiation.
132-kW PV System in California	The interconnecting utility requested a separate package of protective relays duplicating the electronic protection already integrated into the design. The cost was between S25,000 and S35,000 extra, although the utility eventually dropped the request.

Direct Utility Prohibition

In several cases, as shown in Table 2-3, the utility simply prohibited distributed power systems from operating in parallel with the grid; that is, the utility simply refused to interconnect with these systems. In two cases the customers finally decided to operate independently of the grid. Two others eventually decided to abandon their projects. In one case, the utility claimed there was no legal requirement to force it to interconnect and declined to do so.[35] In other instances, the wholesale generation and transmission utility supplying the distribution utility with power invoked "all requirements contracts" to prevent the member distribution utility from allowing interconnection.[36] Even projects installed on the customer side of the meter face prohibitions, some directly and others in the form of requirements to disconnect before operation or other utility limitations of on-site generation.

There were several cases where utilities attempted to block distributed-power facilities, which were allowed under regulations in force at that time, by changing regulations to prohibit future installations. In one case that was particularly egregious, a truck-stop casino proposed a peak-shaving and backup generation system as part of the casino expansion. The municipal utility granted initial approval. Site preparation commenced and equipment was delivered on site. Before installation was completed, the G&T wholesaler approached the city urging it to prohibit the installation. The city reversed its initial approval and immediately adopted a city ordinance to prohibit parallel operation. The ordinance also raised the municipal utility's backup tariff, making the installation uneconomic for non-parallel operation. The installation was abandoned with losses borne by the owner and developer.[37]

In another case, a city responded to a wind power project with a zoning ordinance regulating construction of wind turbines within the city limits, making it very difficult or impossible to get a permit to construct a wind turbine. Since the original site had obtained its construction permit before the ordinance, however, the project proceeded.[38]

Table 2-3
Projects Stopped or Not Interconnected because of Direct Utility Prohibition

Case	Status at Report Date	Technology (Fuel)
75-kW NG Microturbine in California	Pending	Natural Gas (NG)
260-kW NG Recip in Louisiana	Abandoned	NG
500-kW Cogeneration in New England	Abandoned	NG
1-MW Diesel IC Generator in Colorado	Decision to Operate Independent of Utility Grid when Peak Shaving Unit is Operating	Diesel
26-MW Gas Turbine in Louisiana	Decision to Operate Independent of the Utility Grid	NG

[35] Case #15.
[36] Case #6.
[37] Case #10.
[38] 10-kW Wind Turbine in Oklahoma (B).

Tariff Barriers

Among the project owners and developers interviewed, tariffs were most often seen as discouraging distributed power, rather than encouraging it. These tariffs included the following:

- Demand charges and backup tariffs
- Buy-back rates
- Exit fees
- Uplift tariffs (charges for distribution. ancillary services, capacity and losses)
- Regional transmission procedures and costs.

The distributed-generation projects typically offered benefits to the distribution grid in terms of peak shaving, reduced need for distribution system upgrades, and capital cost reductions. These benefits have been well documented in other reports. Nonetheless, the tariffs and rate designs encountered in this study did not account for either the provision of distribution services to the system or the particular benefits to the customer from distributed power.[39] These rate design issues exist in both vertically integrated and restructured utilities.

In some cases, rapidly adopted increases in fees and charges were used to stop development of distributed power projects.

Demand Charges and Backup Tariffs

Supplemental, backup, and standby tariffs—referred to collectively in this report as "backup tariffs" critically impact distributed power markets, because they can determine the economics of distributed power and grid supply in combination. Although every distributed power site could provide its own redundant backup power, the proposed facilities in this study generally sought access to both the grid and distributed power to optimize the combination.

As seen in Figure 2-3, backup charges can pose a significant barrier for both small and large distributed generators. High backup charges can very effectively discourage distributed power by overriding any system or customer benefits with substantial locked-in payments to the utility. Figure 2-3 also shows that standby charges levied by utilities on distributed generation projects can vary over a considerable range. The case studies demonstrate a lack of consistency and the absence of regulatory oversight of backup tariffs.

In deregulated states, backup supply can be obtained from competitive suppliers in the market, where options are transparent. However, unrealistic demand charges included in the distribution and transmission tariff to access the competitively provided backup supply can be as equally detrimental as excessive backup tariffs and render a project economically unfeasible.

In one case, high demand charges with continuing-demand billing ratchets were put in place on the grounds that the system must maintain capacity equal to the annual peak. For example, when the 200-kW fuel cell project is down, the owner is assessed a demand charge of $19.20/kW-month for that time and for the next 12 months thereafter. If the unit is down during a peak demand period, the total cost for one outage could result in an annual demand charge of $46,080. In this case, there was also no recognition given for peak shaving and other system benefits of distributed power.[40]

In another case, a 5-MW cogeneration project was cancelled because the utility assessed the standby charge at $1 million per year.[41] The host facility (a hospital) provided a backup power system, but the utility refused to offer a partial credit for capacity provided by the backup system.[42] In the state of New York, the annual standby charges range from $52.34/kW-year to $200/kW-year—a variance factor of almost four. From the utility/regulatory

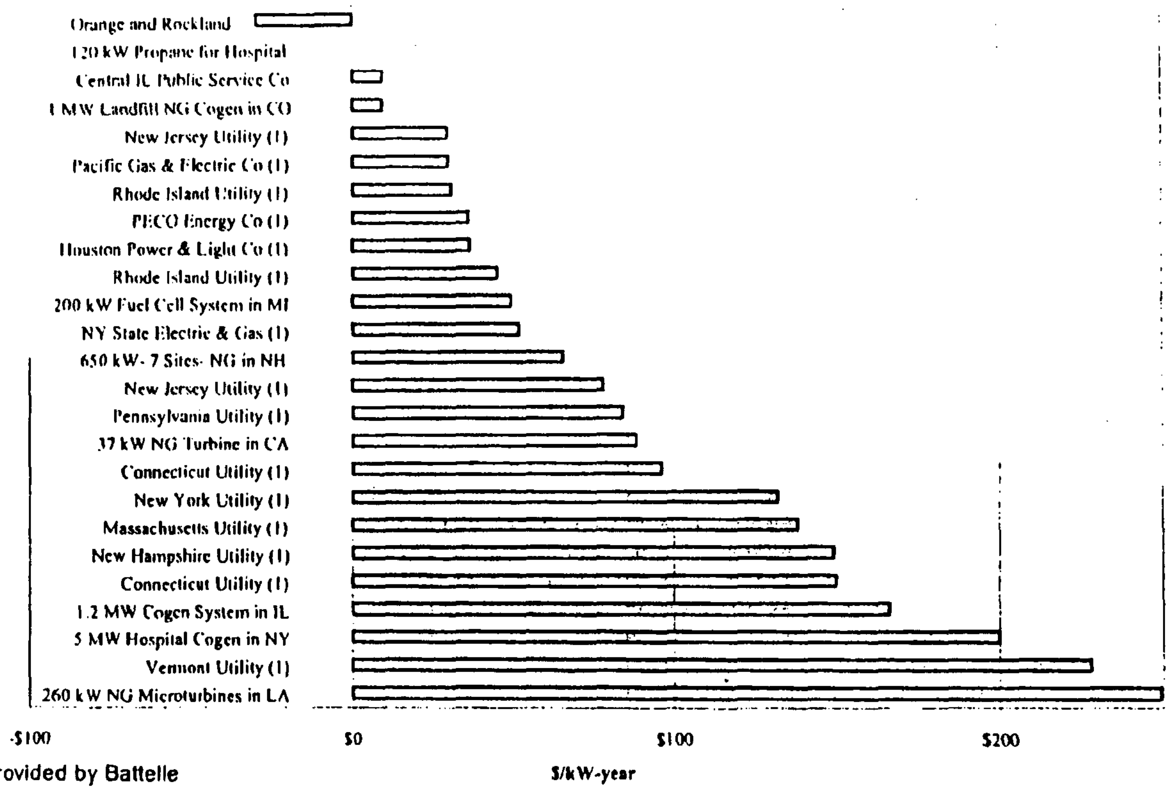
[39] The narrow exceptions that prove the rule are instances like the regional de-averaged capacity purchase tariffs implemented by Orange & Rockland Utility in New York State to utilize customer-sited generation in place of new transmission lines for many years.

[40] Case #11.

[41] Case #5.

[42] The same backup power system would allow the hospital to run independently from the grid during local utility power outages.

Figure 2-3
Annual Back-up Charges for Selected Utilities and Case Studies($/kW-year)



(1) Provided by Battelle

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perspective the type of generation employed to provide backup power can account for different tariffs, but nonetheless this variance has a large effect on the market.

At their inception, some utilities appear to have utilized backup charges to discourage interconnection of self-generation by industrial firms and other commercial customers. The conference report of the Public Utility Regulatory Policies Act of 1978 (PURPA)[43] suggests that some electric utilities purposely priced backup or standby service at a level that made it uneconomical for the customer to implement an on-site generation project. PURPA made this illegal and required utilities to implement reasonably priced backup charges. Nonetheless, regulatory policy and utility practice continue to use standby charges to discourage distributed power that would result in non-economic bypass. This is illustrated by a "Standby Service" document that states as its purpose, "To discourage bypass of the Company's services and charges where such bypass[44] is not economic from society's standpoint and to prevent the shifting of the Company's Competitive Transition Cost (CTC) to other stakeholders that would occur in such circumstances."[45]

The conditions under which backup tariffs are applied also vary. For example, some tariffs apply demand charges as well as backup service rates.[46] In one case, the municipal utility created a new standby tariff specifically designed to stop a distributed power project. The city calculated a charge for 25,000-kWh of supplemental power at $5,400 under the newly adopted tariff, as compared to the total previous standard bill for 80,000-kWh at $6,000. It appears that the utility established the tariff to dissuade the customer from proceeding with the distributed-power facility, since the new tariff is triggered by the existence of "installed equipment" independent of the customer's load profile. A customer with the same energy usage and load profile without such equipment on-site would presumably continue to receive bills under the more favorable standard tariff. In short, the purpose appeared to be solely to discourage on-site power installations. See the discussion of the 260-kW natural gas generation system in Louisiana in the case studies.[47]

Another case involved a utility's attempt to obtain a backup tariff that would have assessed a 120-kW facility a $1,200/kW-per-annum charge, or approximately $144,000 annually. Even if the facility operated constantly (as a baseload plant), it would only generate approximately $100,000 worth of electricity annually. The PUC rejected the tariff, stating that if the facility was shut down the utility would not notice.[48]

[43] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, page 89, 95th Cong., 2d sess. (1978).

[44] There is a difference in regulatory treatment of what is termed "economic" versus "non-economic" bypass. Economic bypass might occur where a new technology serves increased load in the territory at a cost less than the marginal cost to the utility of serving such a load. Non-economic bypass, however, is a concept that essentially admits that a particular customer has been asked by the regulatory regime to pay more than the utility's marginal cost to serve it as a result of policy considerations, and that unless the tariff rate is reduced to something below the cost to self generate, but above the marginal cost of service, the customer can save money by self generating even though it is paying more than the utility's marginal cost. The regulatory reasoning is thus that it is better to have the customer make some contribution to the fixed costs of the utility by paying something over marginal costs rather than leaving the system, which could incur the fixed costs increase for all. For example, one statement of the regulatory position states: "Non-economic bypass and the inappropriate shifting of the fixed cost of the electrical system between or among customers are not fair and efficient competition, are contrary to the public interest, and should be avoided. Customers of continuing monopoly service should benefit, or at least not be harmed, by choices made by customers with competitive options." Washington Public Utility Commission Interim Policy Statement Guiding Principles for an Evolving Electricity Industry, August 14, 1995. See http://www.energy online.com/Restructuring/models/washing1.html.

[45] 2-kW PV System in New York

[46] 40 sites-60-kW NG IC Systems in California

[47] Case #10.

[48] Case #14.

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capacity shortages in a manner that benefits all parties. (See discussion at page 17.)

Exit Fees

As more states adopt stranded cost charges as part of restructuring, exit fees have emerged as a major barrier to new distributed-power technologies, in some cases a long-term barrier. The potential amount of the charges—up to 2¢/kWh or more—is having a significant impact on incentives for customer load management in general.

As with other barriers, the variations in exit fees and related charges and in utility collection practices from state to state make the development of national markets for distributed power more difficult. For example, New Jersey exempted customer on-site generation and load management from exit fees unless and until a utility's combined loads drop to 92.5 percent of current levels. Neighboring Pennsylvania, which is within the same ISO region, retains exit fees through 2010 for some utilities at rates in excess of 2¢ /kWh. Some California utilities have threatened collection of exit fees for customers considering on-site combined heat-and-power options. Especially in areas of load growth and supply shortages, the rationale for tying exit fees to historical use with its intentional dampening effect on customer-side supply-and-demand options needs to be reviewed by regulators and other policymakers. The recent Texas rules confirm the system benefits provided by distributed generation in such instances. The New Jersey approach of allowing distributed power to grow in step with current market demand also formally recognizes the benefits of providing distributed power access to the market. Similarly, Connecticut is assessing the applicability of exit fees to combined heat and power and other Qualifying Facilities under FERC regulations, as well as considering whether there would be enough cogeneration activity for exit fees to be a significant issue.

Uplift Tariffs

In competitive electricity markets, the distribution utility does not define the market for power from distributed facilities. Instead, the newly opened competitive market for wholesale and retail supply defines the market. The utility's buy-back rate is therefore not the critical issue in competitive markets that it is when the utility constitutes the sole potential buyer. Rather, the competitive issue shifts to the rate to be charged by the distribution utility for transmission of the power to the market. Many of the metering and technical interconnection issues are technically the same, but competitive markets have given rise to additional charges for "distribution wheeling," which includes distribution capacity and ancillary services, up to the transmission level (uplift tariffs) as well as additional tariffs, procedures, accounting and scheduling at the regional transmission level.

In the projects studied for this report, utilities proposed a variety of uplift tariffs, charges, and penalties. In several cases the per-kWh charges were dropped after lengthy negotiations. The cases in this study encountering uplift tariffs were renewable energy facilities intending to supply "green market" power to the regional grid system. In one case, the tariff proposed was based on peak production at $5 per kW-month for the uplift, which amounted to about 0.7 ¢/kWh for high capacity factor generation units (about 1.5¢ per kWh for lower capacity factors as occurs with wind generation). This tariff resulted from application of the distribution company's open access (or wholesale) tariff applicable to large generation—applied in full—despite the fact that the power was to be generated and used locally, without ever reaching the utility's transmission facilities.[53]

The absence of any commonly accepted ratemaking principles for these distribution charges is a significant issue, particularly given the potential system and market benefits of

[53] Case #7.

distributed power. Using common rate-making principles, as distributed power typically reduces loads on the distribution (and transmission) systems, distributed power should under some circumstances be entitled to a credit rather than a charge.

Regional Transmission Procedures and Costs

In today's competitive wholesale electricity markets, delivery of power into the regional transmission market, is governed by rules that have been designed by and for large-scale generation. Like the rates and rules developed for the central station model at the distribution level, these rules are often inappropriate or prohibitively expensive for smaller-scale distributed power. With the creation of independent system operators (ISOs) to manage regional transmission markets, the access issues have become even more complicated for smaller distributed generation projects. Regional transmission organizations (RTOs) and ISOs frequently fail to recognize or account for capacity less than one megawatt, which may thus require aggregation of systems to participate at the RTO/ISO level, another barrier to competitive markets.

In one case study, the project developer determined that under existing rules in California, distribution-level generators have no way to wheel power to the ISO responsible for coordination and dispatch of power under retail competition in California. This apparent absence of any market path was reflected in the original utility proposal, which specified that the utility would not wheel power on behalf of the project. The project developer understood that the California ISO might itself be looking at solutions to this problem, but at the time of this review the issue remained unresolved.[54]

In the New England ISO region, application of the full regional transmission tariffs, including ancillary service and loss rules were the pivotal barrier to a proposed 1-MW landfill gas project, which was abandoned as a result. The regional transmission charges were to be assessed even though the proposed project would serve only local loads within a single distribution area. Alternative "point-to-point" transmission tariffs, which required interval metering and telemetering of data to the system operator were more expensive than local distribution system service.[55]

Another case involved a similar experience with an ISO. The ISO sent a letter that turned the matter over to the local distribution company. A wind developer planning a 130-kW market pilot facility completed lengthy negotiations with technical and legal personnel of the distribution utility over proposed interconnection engineering fees. These fees were in excess of the projected first year gross revenue from the project. The proposed fees included payment of the utility's legal fees to prepare an agreement covering all items included by other utilities in a tariff. As initially presented, the agreement included a specific distribution line loss number to six decimal places (just over 2.5 percent), in addition to any ISO loss assignments. As the facility was prohibited from generating more than one-third of the minimum load on the distribution system, its actual impact was to reduce supply losses for the utility. The distribution loss charge was eventually dropped. After several months of negotiation with the distribution utility, the ISO informed the developer that a separate interconnection service agreement with the ISO would also be required.[56]

A standard regional transmission and ISO approach is to assign losses of five to nine percent to all retail loads on the assumption that they are being served from the pooled transmission facilities. That approach requires five to nine percent more generation delivered than load served. One of the core competitive advantages of distributed generation is its intentional placement in close proximity to the loads served, precisely in order to reduce transmission and distribution costs such as line losses. The application of the same rule-of-

[54] Case #13.

[55] Case #7.

[56] 130-kW Wind Turbines in Pennsylvania.

thumb line loss charges applied to bulk power is both illogical and anti-competitive vis-à-vis distributed power. In one of our cases, a landfill facility intended to serve local loads would not, in fact, have used a transmission path (contract or actual), but nonetheless was charged for transmission losses. Even where the distributed power is sold into the transmission grid, in most cases, by virtue of its location on the distribution system, distributed generation has the actual physical effect of reducing system losses.

Distribution utility responses to requests to market "wholesale" distributed power are widely inconsistent. Certain aspects of the typical proposal to a distributed generation interconnection are troublesome from the viewpoint of distributed utility developers. First, there are no provisions for credit or value for reduced losses on the distribution and transmission system and reduced power import as a result of distributed power. Second, some utilities have attempted to add additional loss adjustments and distribution charges on top of assigned transmission losses.

There was one proposal for ISO accounting treatment of small (under 1-MW) distributed power sources as "negative loads," which resulted in a credit at the wholesale transmission level for metered generation plus nine percent. While this latter approach is more consistent with system benefits produced by distributed power, this treatment is the exception rather than the rule, and is the inadvertent result of ISO accounting rules. This ISO, however, is reported to be reconsidering this treatment.[57]

Selective Discounting

Like the concept of uneconomic bypass, undisclosed selective discounts run counter to efforts to increase transparent competitive markets and innovation as supplements to regulation. From this perspective, state-sanctioned price discounting under public utility commission-enforced secrecy can be an absolute barrier to the creation of viable markets for on-site distributed power. Case study respondents reported economic development tariff discounting as one of the utilities' most commonly used tools to keep large electric customers from pursuing more economic distributed power alternatives. Combined heat-and-power (CHP) projects, gas turbines, and other larger distributed technologies were offered multiple rounds of discounted pricing, to the point where several vendors report utility discounts as the most common customer benefit arising in the market for these innovative technologies.[58]

In one case, a CHP project was abandoned when the utility offered the customer a seven-year guaranteed price incentive. The utility made 25 progressively better proposals to the customer before the final offer was made, even though the CHP project would have actually produced power more efficiently, with lower actual production costs and environmental emissions,

[57] Case #7.

[58] One of the fundamental principles of monopoly tariffs is "the obligation to furnish service and to charge rates that will avoid undue or unjust discrimination among customers," which results in similar customers within a rate class paying the same rates [See: *Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R Kamerschen, PUR, Inc. Second Edition, 1988, at p. 515]. Before the advent of competitive utility services and the emergence of advanced distributed power technologies, utilities and regulators developed an exception to this principle that permitted special discount rates for those few large customers who had a genuine self-generation alternative and threatened to leave the system. Some times the customers' choice of on-site generation was thought by the regulators to be an inappropriate option in terms of the whole system. This was because the actual cost of the power exceeded the regulated utility's variable cost. Thus if an amount equal to the self-generation cost was paid to the utility the amount would cover variable costs and make some contribution to fixed costs. The potential self generation alternative was termed "uneconomic bypass." To avoid the lost contribution to fixed costs associated with uneconomic bypass, many states permitted utilities to reduce rates down to marginal costs to keep large customers from leaving the system.

than the traditional generation provided by the utility.[59]

During the bidding process the customer used this leverage to pit the utility and the distributed power supplier against one another to negotiate a discounted deal for its power. In the final hours of contract negotiation between the equipment supplier and the customer, the utility presented the combined offer it had brokered with the regulatory authority to persuade the customer to abandon the cogeneration project.[60]

In a case not included in this study, the project developer reported that the utility successfully negotiated a deal with the big three automakers to reduce their rates by three percent to five percent in exchange for a long term agreement to not install local generation systems.

Obviously, discounted utility power is advantageous for customers who can get it, at least for the term of the discount. But access to these discounted rates is unpredictable. Even where customer discounts are made available, they are often limited in duration. In one case where a customer was considering cogeneration, the utility offered the customer a better rate, but delayed its implementation for almost two years. Some discounted rates only last for a short period such as a year or two then revert to previous higher levels.[61] Finally, the requirements for obtaining the discount sometimes require expenditure of funds to show serious intent to leave the system. An expenditure of several thousand dollars for engineering demonstrating a combined heat and power facility supported a reduction by 11.77 percent discount, approved by one state's PUC.[62]

Environmental Permitting Requirements As Market Barriers

Environmental permitting requirements can be a significant barrier in many regions of the country, especially for smaller projects. For many projects covered in this report, environmental testing and emissions requirements were as stringent for small projects as for larger projects. As with custom engineering requirements and other similar costs, smaller projects cannot bear the same cost of emissions testing as larger projects and remain feasible. In one case, for a 60-kW installation of natural-gas fired power supply, projected initial costs were $2,500 for testing and $200/month for inspections.[63]

Unfortunately, distributed generators as well as larger merchant plants are treated as new sources even when they displace older, inefficient, and polluting sources.[64] Worse, in the projects reviewed in this report, cogeneration facilities were assessed for environmental permit purposes based on combustion efficiency and not overall energy output efficiency and thus are not given credit for the added thermal energy used.

While beyond the scope of this study, environmental permitting issues will need to be addressed by the appropriate agencies, as most current siting processes were designed for large power plants, thus posing barriers to distributed power analogous to those more fully discussed in this report.

[59] Case #4.

[60] The utility further blocked this cogeneration project by assessing transport rates for natural gas to the proposed cogeneration facility (through its distribution pipes at a cost that was nine times higher than the rate the utility charged itself). Case #4.

[61] 560-kW Cogeneration System in New York

[62] Case #14.

[63] 40 sites-60-kW NG IC Systems in California

[64] One project owner attempted to install cogeneration to replace oil fired boilers; however, the local air board would not allow emissions credit. The air board requested 99 percent improvement, not just 90 percent. Similar situations were reported in several other cases. 8-MW Cogeneration System in New England.

2.5 Barrier-Related Costs of Interconnection

To attempt to quantify the various categories of barriers to market entry for distributed generators, the customer or developer was asked in each case to estimate the "barrier-related" costs arising in each case study. Costs defined as "barrier-related costs of interconnection" included the customer's or developer's estimate of the costs of the various barriers discussed in this report.

These cost estimates do not include extra time spent by project developers or customers, nor do these cost estimates include lost savings because of utility delays, annual fees, or other tariffs (except exit fees). Backup charges were only included as a one-time charge if they stopped the project. These estimates are thus strictly "out of pocket costs" that exceeded the project developer's necessarily subjective determination of appropriate, anticipated, interconnection costs.

Table 2-4 provides a summary of the barrier-related costs by project for the 25 cases for which costs above normal were reported. Figure 2-4 provides the costs in $/kW.

Figure 2-5 shows the interconnection costs above normal for renewable projects, whereas Figure 2-6 quantifies the costs for fossil fuel projects. These lists do not include 16 projects where no barrier-related costs were reported.[65] In addition, six projects are not included in these data because they did not interconnect. Cost estimates were not known for another 18 of the projects.

As can be seen in Figure 2-4, barrier related interconnection costs in one state ranged from $5.81/kW to $1,333/kW. Smaller projects were affected more than larger projects.

[65] Some of these 16 projects reported "excessive" annual backup charges which were not included because the project interconnected and the backup charge was an annual charge.

For illustrative purposes, the expected costs to interconnect a 43-kW commercial PV system in Pennsylvania were included even though this facility did not attempt to interconnect. Interconnection was prohibited because the project developer estimated that it would cost between $30,000 to $40,000 ($698/kW-$930/kW) in consulting and engineering fees.

2.6 Findings

By interviewing proponents of distributed generation projects about problems encountered in seeking utility grid interconnection, this study identifies a variety of barriers to the interconnection of distributed generation projects. The anecdotal nature of this study presents the barriers from the perspective of the proponents and does not assess their prevalence. The study does, however, show that the barriers are very real, that they can block what otherwise appear to be valuable projects, and that they are independent of technology or location.

More than half of the case studies identified barriers in each of the categories: technical, business practice, and regulatory. Technical barriers principally center around equipment or testing required by utilities for safety, reliability, and power quality. Project proponents often felt that these requirements were unnecessarily costly because their generating equipment and related facilities already included adequate safety, reliability, and power quality features.

Many developers indicated that the utilities' interconnection-related business practices were among the most significant barriers they encountered. A common problem is the difficulty and length of the interconnection approval process, often resulting from a simple lack of a designated utility contact person or established procedure. Other business practices seen as unnecessary barriers by project proponents—particularly for smaller projects—included application and interconnection fees and insurance requirements.

Table 2-4
Barrier Related Interconnection Costs- Costs Above Normal ($)

Case	Technology	Costs Above Normal
2.4-kW PV System in NH	PV	$ 200
17.5-kW Wind Turbine in IL	W	$ 300
300-W PV System in PA	PV	$ 400
0.9-kW PV System in New England	PV	$ 1,200
3.3-kW Wind/PV System in AZ	PV/W	$ 4,000
140-kW NG IC System in CO	NG	$ 5,000
10-kW Wind Turbine in TX	W	$ 6,000
20-kW Wind/PV System in Midwest	PV/W	$ 6,500
120-kW Propane Gas Reciprocating Engine in HI	Propane	$ 7,000
37-kW Gas Turbine in CA	NG	$ 9,000
90-kW Wind Turbine in IA	W	$ 15,000
132-kW PV System in CA	PV	$ 25,000
43-kW PV System in PA	PV	$ 35,000
2100-kW Wind Turbines in CA	W	$ 40,000
40 sites of 60-kW NG IC Systems in CA	NG	$ 50,000
50-kW Cogeneration System in New England	CG	$ 50,000
75-kW NG Microturbine in CA	NG	$ 50,000
260-kW NG Microturbines in LA	NG	$ 65,000
703-kW Steam turbine in MD	CG	$ 88,000
Seven sites of 650-kW IC NG System in NH	NG	$ 300,000
500-kW Cogeneration System in New England	CG	$ 500,000
21-MW NG Cogeneration System in TX	CG	$ 1,000,000
15-MW Cogeneration System in MO	CG	$ 1,940,000
26-MW Gas Turbine in LA	NG	$ 2,000,000
3 to 4-MW NG IC System in KS	NG	$ 7,000,000

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Figure 2-4
Barrier Related Interconnection Costs Above Normal ($/kW)

Costs are estimated by Owners/Project Developers as the costs above normally

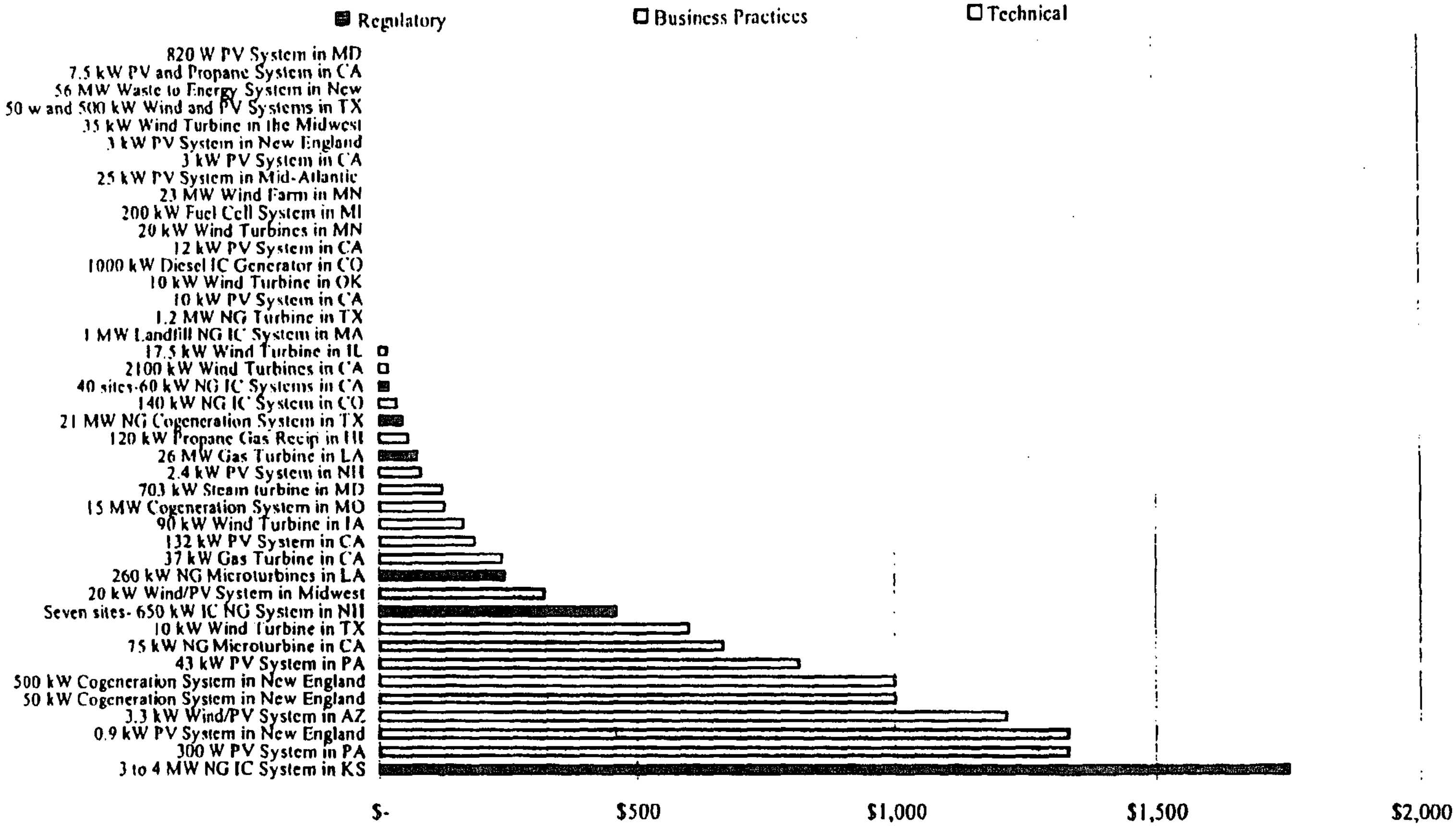

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Figure 2-5
Barrier Related Interconnection Costs for Renewable Projects ($/kW)

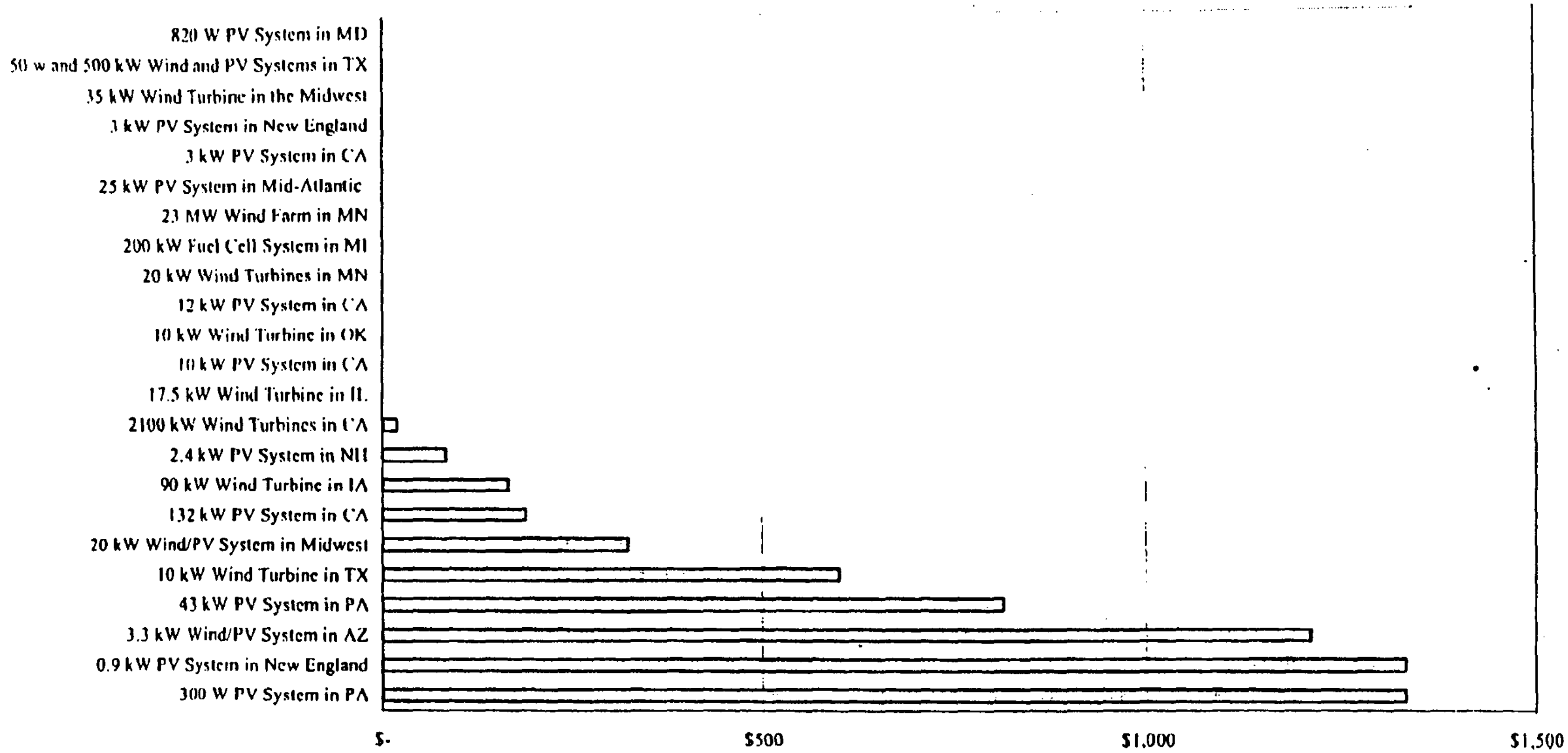
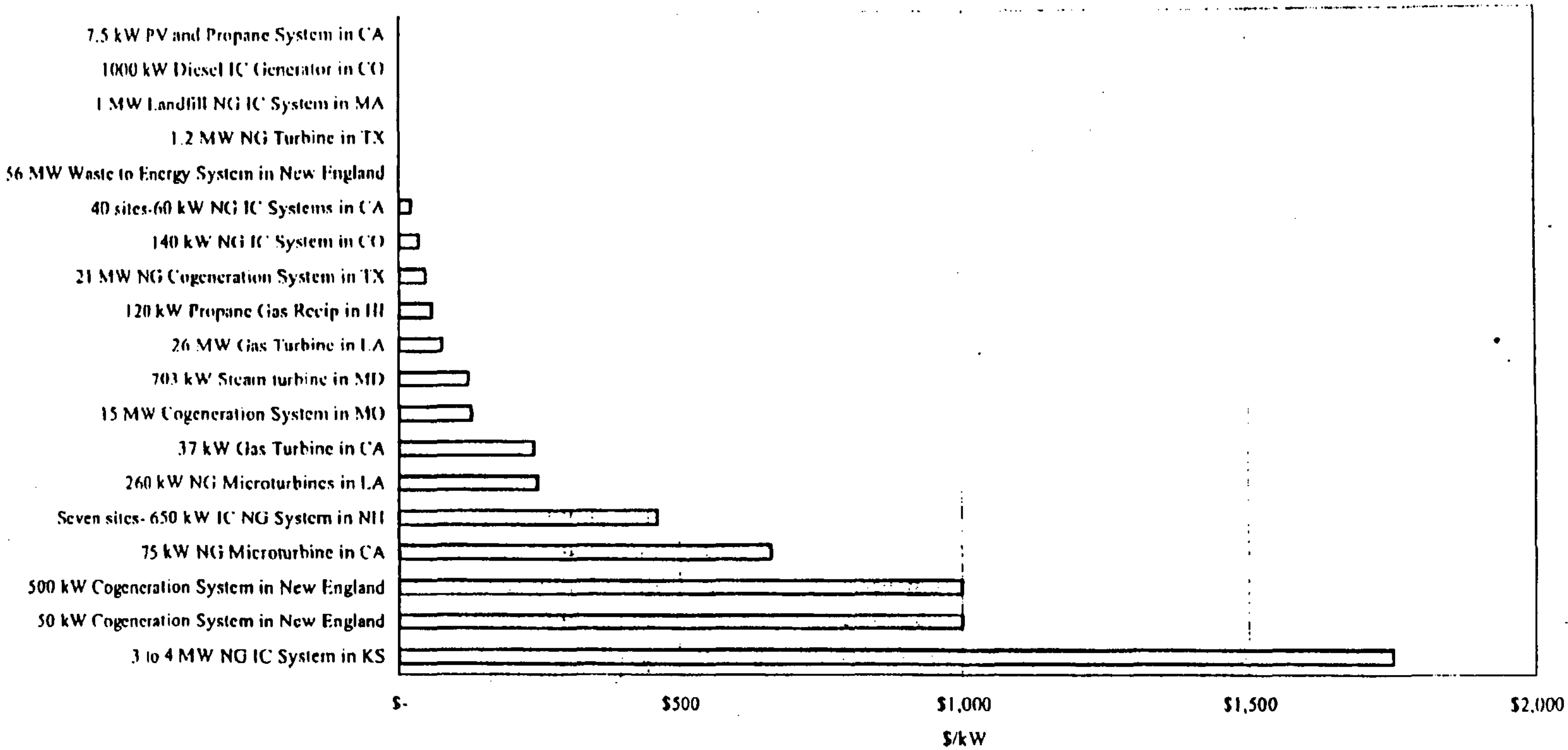


Figure 2-6
Barrier Related Interconnection Costs for Fossil Fuel Projects $/kW



The regulatory scheme under which distribution utilities operate presents formidable barriers for distributed power technologies. These barriers go beyond the problems of technical interconnection requirements or utility delay, which are more readily apparent to the market. They grow out of long-standing regulatory policies and incentives designed to support monopoly supply and average system costs for all ratepayers. Today, the customer's desire for onsite generation is the driver for distributed power markets. The regulatory regime for distribution utilities is least prepared for this customer-driven market, and significant barriers arise as a result. In the present regulatory environment, utilities have little or no incentive to encourage distributed power even in cases when it provides benefits to the distribution system. To the contrary, regulatory incentives understandably drive the utility to defend itself against market entry of distributed generation. Revenues based on throughput and system averaged pricing are optimized by keeping maximum loads and highest revenue customers on the system.

Among the barriers identified in the case studies as sources of contention capable of blocking projects were excessive charges for supplemental utility power, for utility capacity needed in case the customer needs replacement utility power (backup charges), for transmitting the customer-generated power to other customers (wheeling charges), and for leaving the utility system (exit fees because of stranded costs), as well as rates paid by the utility for the customer-generated power which did not fully credit its benefit to the grid. Additional distribution and transmission charges for selling power from the customer site to either the utility or the wholesale market are raising new tariff issues with widely divergent results from one utility territory to another, leading to Federal Regulatory Commission interest in the area. While some utilities, regulatory commissions, and independent system operators have implemented tariff structures specifically dealing with distributed generation, there is not yet an accepted set of regulatory principles to be applied in an efficient national framework to accommodate distributed generation.

The Barriers

Several common patterns emerge from review of the 65 case studies in this report (with 26 representative examples presented in detail in the next section).

- There are a variety of technical, business practice, and regulatory barriers to interconnection in the US domestic market.
- These barriers discourage and sometimes prevent distributed generation projects from being developed.
- The barriers exist for all distributed-generation technologies and in all parts of the country.
- The impacts of lengthy approval processes, project-specific equipment requirements, and high standard fees are particularly severe for smaller distributed generation projects.
- Many barriers being encountered in today's marketplace appear to derive from or are more significant because of the fact that utilities have not previously dealt with many small-project or customer-generator interconnection requests.
- Many barriers also derive from or are more significant because there is not yet a national consensus on technical standards for connecting equipment, necessary insurance, reasonable charges for activities related to connection, or agreement on appropriate charges or payments for distributed generation.
- Utilities often have the flexibility to remove or lessen barriers.
- Distributed generation project proponents faced with technical requirements, fees, or other barriers that they found too burdensome are often able to get those barriers removed or lessened by informally protesting to the utility, to the utility's regulatory agency, or to other public agencies. But, this usually requires considerable additional time, effort, and resources.
- Official judicial or regulatory appeals, however, were often seen as too costly for relatively small-scale distributed generation projects.

- Distributed generation project proponents frequently felt that existing rules did not give them appropriate credit for the contributions they make to meeting power demand, reducing transmission losses, or improving environmental quality.

Suggested Actions To Remove or Mitigate Barriers

The purpose of this study was to review examples of the barriers that non-utility generators of electricity encounter when attempting to interconnect to the electrical grid. In the course of the study, developers and utilities sometimes suggested solutions to these barriers. From these suggestions, the authors compiled a list of actions that could begin to eliminate unnecessary market barriers.

One of the key action items was the need to encourage collaborative action. Although regulatory proceedings and legal challenges eventually would resolve most of the barriers identified, collaborative efforts among all stakeholders are likely to resolve barriers more quickly and efficiently than potentially adversarial proceedings.

The other action items were divided into three categories: reducing technical barriers, reducing business practice barriers, and reducing regulatory barriers.

Reduce Technical Barriers

Adopt uniform technical standards for interconnecting distributed power to the grid — Standardized interconnection requirements, sometimes called "plug and play" standards, are key to opening markets for manufactured distributed power equipment. This equipment could have the necessary safety and power quality protection built in at the factory if national standards were in place. Industry and the U.S. Department of Energy have been working through the auspices of the IEEE to develop standards for the interconnection of distributed generation resources to electrical power systems, to meet safety, power quality, and reliability requirements. Uniform adoption of the resulting standards is necessary to eliminate the barrier posed by project-specific interconnection requirements.

Adopt testing and certification procedures for interconnection equipment — For the IEEE interconnection standards to be effectively implemented, testing and certification procedures must be in place to assure that generating equipment and the associated interconnection devices which provide the interface with the electric power grid meet the standards. Equipment that is "pre-certified" can be confidently approved by utilities as meeting their safety and power quality concerns without any further review. Equipment manufacturers will depend on being able to pre-certify equipment because the economics of distributed power requires mass production of equipment that can be installed and operated with minimal site-specific engineering. Stakeholders interested in promoting distributed power should expedite the task of pre-certification through appropriate testing and certification organizations and should fully support the adoption and use of pre-certified equipment.

Accelerate development of distributed power control technology and systems — If the use of distributed power is to grow beyond isolated installations, grid operators need access to control and system integration technologies that allow optimal use and delivery of the power. These technology needs cover a broad range of systems operation research and development issues addressing open architecture, real time monitoring, control, command, communications, quality, reliability, and safety.

Reduce Business Practice Barriers

Adopt standard commercial practices for any required utility review of interconnection — Delays and expense arising from the lack of standard utility procedures for dealing with distributed power was one of the most frequently cited complaints of distributed power project proponents. Specific complaints included the absence of any utility contact person to handle interconnection requests, or unpredictable and open-ended initial price quotes from the utility for processing interconnection requests. Recent regulatory attention in some states, notably Texas

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and New York, promises to help by setting uniform statewide procedures. Utilities, vendors, developers, regulators, and their associations can adopt standard business practices for handling interconnection requests.

Establish standard business terms for interconnection agreements — The terms and conditions of utility interconnection agreements (often modeled on agreements applicable to much larger facilities) were cited as barriers by many surveyed distributed power project proponents. Fees, studies, insurance and indemnification requirements, and operating limitations appropriate for large utility generators may not be necessary for smaller facilities and act as significant impediments to distributed power installations. These requirements also vary tremendously from utility to utility, which deters commercial scale marketing. Some states have adopted simple "one page" agreements and reasonable insurance limits for residential- and small commercial-scale systems. Other states have begun to address standard terms and fees for industrial-scale distributed power. Using a collaborative process of the type used in connection with the Texas regulations, distributed power stakeholders can develop standard business terms and provisions for uniform adoption by utilities and regulators.

Develop tools for utilities to assess the value and impact of distributed power at any point on the grid — Distributed power can offer significant system benefits for utilities and grid customers as a whole. These benefits include reducing transmission and distribution losses, leveling out demand profiles, saving higher cost distribution investment, and avoiding new central generation or transmission lines, among others. Transmission system planners are accustomed to monitoring networks and their operating instabilities and to analyzing investment tradeoffs. Prior to the recent growth in distributed generation, however, there has been little need for that kind of analysis for distribution systems. Accordingly, case study respondents reported that having the means to quickly assess the impacts and benefits, technical and economic, of a proposed distributed power project at a particular location would assist in more accurate utility response and price signals to optimize deployment of these new distribution system resources. Utilities, regulators, and distributed generation proponents need to collaboratively develop these tools in time to support the new markets for distributed power.

Reduce Regulatory Barriers

Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets — "Anti-bypass" provisions under traditional regulatory principles allow utilities to discourage distributed power, particularly larger customer-sited projects, by offering customers discounts to stay with the utility. Other traditional regulatory requirements create financial incentives for utilities to discourage loss of load or to add charges to distributed power facilities for use of the distribution system. New principles are needed to balance the interests of various customer classes, and to address market efficiencies and environmental benefits. A national policy dialogue among traditional utility stakeholders and the newer market entrants should develop consensus on new principles governing the new markets.

Adopt regulatory tariffs and utility incentives to fit the new distributed power model — For many of the case studies, the primary barrier was a utility tariff rate specifically applied to onsite generation. For example, utilities sometimes assessed backup tariffs near or even exceeding the prices previously charged for full electrical service. Also, back-haul or uplift tariffs arise under state and federal jurisdiction. These tariffs can create what were in several cases insurmountable barriers to delivering locally generated power to wholesale markets. In some states, customers are charged exit fees for disconnecting from the grid—forgoing the interconnection benefits of backup power and access to wholesale markets. Tariffs balancing customer, utility and market interests need to be developed consistent with appropriate applicable regulatory principles. Likewise, new mechanisms under which the utilities can earn financial rewards, rather than incur financial penalties, for optimizing the use of distributed power must be part of the new regulatory approach to these markets.

Establish expedited dispute resolution processes for distributed generation project proposals — Relief delayed in many cases was relief denied for new distributed power entrants attempting to enter the market. The case studies in this report showed a strong pattern of reduced interconnection barriers when distributed power project proponents contested them. Official regulatory agency challenges, however, were typically seen as too difficult and costly, especially for smaller projects, and many proponents did not or could not economically pursue such challenges. Regulatory bodies and distributed generation stakeholders should develop expedited dispute resolution processes for distributed generation projects.

Define the conditions necessary for a right to interconnect — The combination of acceptable technical standards, business practices, and regulatory principles implies a right to interconnect to the public network under those defined conditions. But unlike the public telecommunications network, where the right to interconnect customer-owned equipment is established under similar standards imposed by both the states and the Federal Communications Commission, there is not now any established underlying right to connect to the electric grid. There were several case-study examples of distributed power proponents being denied interconnection and parallel operation by either investor owned or publicly owned utilities. For the potential benefits of competitive markets and distributed power to the nation's energy system to be realized, the conditions under which distributed power facilities have the right to interconnect should be explicitly addressed rather than left to case-by-case determination. For example, new customer-sited protective equipment can prevent exports of power to the grid and safely disconnect from the grid when necessary, allowing customers the freedom to generate for their own load while assuring safety for other grid customers. These "no export" customer-sited options, subject to certification under approved standards, are one category that should universally be allowed to interconnect. Defining the conditions that support a universal right to interconnect is key to unlocking the national market and customer investment in these promising distributed power technologies.

A Ten-Point Action Plan For Reducing Barriers to Distributed Generation

Reduce Technical Barriers

(1) Adopt uniform technical standards for interconnecting distributed power to the grid.

(2) Adopt testing and certification procedures for interconnection equipment.

(3) Accelerate development of distributed power control technology and systems.

Reduce Business Practice Barriers

(4) Adopt standard commercial practices for any required utility review of interconnection.

(5) Establish standard business terms for interconnection agreements.

(6) Develop tools for utilities to assess the value and impact of distributed power at any point on the grid.

Reduce Regulatory Barriers

(7) Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets.

(8) Adopt regulatory tariffs and utility incentives to fit the new distributed power model.

(9) Establish expedited dispute resolution processes for distributed generation project proposals.

(10) Define the conditions necessary for a right to interconnect.

SECTION 3 CASE STUDIES

In this section we provide narrative descriptions of 26 case studies included in this project. We chose the 26 case studies as a representative cross section of the 65 cases studied. These case studies were also the ones for which the most detailed and reliable information was available. Our intent was to represent large and small projects alike. Initially, we equally represented each size category; however, the 25-kW to 1-MW size range had several cases that were worthy of detailed representation. Specific case studies could be segregated either by technology (i.e., wind, solar, gas turbine) or by size of the facility. Some utilities with interconnection procedures evaluate projects by size. Thus, our report adopts this protocol, and we address three size ranges of distributed power projects, as follows:

- 1 MW and Greater
- 25 kW to 1 MW
- Up to 25 kW.

Each case study is organized to report the background of the project (with confidential information deleted), benefits of the project, barriers to market entry, costs associated with the barriers, and the utility's stance when available. In each case study, we classify the barriers to market entry as follows:

- Technical interconnection barriers
- Business practice barriers
- Regulatory barriers.

The factual information in these case studies is derived principally from interviews with the developers and owners of these distributed power facilities. Although we made efforts to confirm key facts with other stakeholders, particularly the interconnecting utilities, these narratives remain in effect the distributed generators' narratives. Not all the information provided could be independently verified. Thus, these case studies primarily represent the developers' view of the situations they encountered in seeking to interconnect their facilities. We viewed our task as reporting the barriers they described, not assessing the legitimacy of their concerns. Therefore, the case studies reported here may not reflect what might be a very different utility position with respect to some of the cases.

3.1 Individual Case Study Narratives for Large Distributed Power Projects (One MW and Greater)

This section provides a detailed description of eight larger distributed power installations. Barriers to entry into the market place changed as the facilities installed increased in size. Developers and vendors installing larger projects tended to be different than those installing smaller projects, as did the customers. Larger distributed power facilities (one MW and larger) can be installed for a variety of different types of organizations that might include:

- Large commercial users
- Large industrial users
- Generation companies
- Distribution companies
- Municipalities
- Cooperatives.

In our study, we interviewed 16 organizations that installed, are planning to install, or attempted to install distributed power between one and 10 MW in size. We also interviewed six organizations with generation greater than 10 MW.[66] Of these projects, 13 are for municipalities, city/community facilities, or utilities.

Larger projects tend to serve specific types of applications such as CHP[67] projects. CHP projects are typically primarily connected as baseload facilities because many times the need for heat or steam cannot be supplied from another source. In those cases, the electricity is generated independent of system peak.

[66] We did not seek out distributed power projects larger than 100 megawatts because the issues of customer access or transmission access invoke different technical and other considerations.

[67] Cogeneration is the production of steam in conjunction with electricity. The steam is used for an alternative source such as hot water heating or processes. This is also referred to as CHP or combined heat and power.

Ten of the sixteen projects from 1 MW to 10 MW are CHP, and four are methane gas-to-energy projects.

Eight of the 22 larger distributed power examples are summarized below as a cross section of the barriers encountered. The case studies organized by size are as follows:

- 26-MW Gas Turbines in Louisiana
- 21-MW Cogeneration System in Texas
- 15-MW Cogeneration System in Missouri
- 10-MW Industrial Cogeneration System in New York
- 5-MW Hospital Cogeneration System in New York
- 1.2-MW Natural Gas Turbine in Texas
- 1-MW Landfill Gas-to-Energy System in Massachusetts
- 750-kW and 1-MW Diesel Generators in Colorado.

Case #1 — 26 MW Gas Turbine Cogeneration Project in Louisiana

Technology/size	Natural Gas Turbines—Cogeneration/Six 5.2-MW units
Interconnected	No
Major Barrier	Regulatory—Discount Tariff
Barrier Related Costs	$2.000.000
Back-up Power Costs	Not Known

Background

The industrial customer had contracted with a distributed generation developer to build a 26-MW gas turbine cogeneration plant at its production facility. The plant was scheduled to be on-line in November 1999. at which point the industrial customer planned to disconnect from the utility distribution grid. The project includes six 5.2 MW turbines with synchronous generators. five of which would run continuously. and one of which would be reserved for duty during planned and unplanned outages of the primary units. Each of these units had 100.000 lb/hr boilers on heat recovery to achieve 92 percent thermal efficiency.

Once the installation is completed, the industrial customer's primary benefits will be on-site generation of electricity and steam. The new gas turbines will provide a dramatic reduction in carbon dioxide and nitrogen oxides emissions by replacing the old, less efficient, boilers. The industrial customer will enjoy much higher power reliability than from the utility grid.

Regulatory Barriers

Discount Tariffs

The greatest barrier to building this cogeneration facility was the utility's existing and regulatory-agency-approved steam user subsidy. This subsidy allows the utility to offer discount rates to customers who use steam; the more steam they use the greater the discount available.

The utility invoked this subsidy, offering seven- to ten-year long discount rate contracts to retain customers who were intending to build their own cogeneration facilities. The utility's annual lost revenue from this cogeneration project would be approximately $8.8 million for electric loads alone.

Environmental Permitting

Another hurdle in the approval process for this plant was the air emissions permit. The state air regulatory board appears inconsistent from case to case and area to area. In this case, the old boilers being replaced were fired on #6 diesel. The developer proposed to burn much cleaner natural gas, but the state air regulatory board position was that as a "new" source the facility must meet 99 percent improved efficiency. Ninety-percent improved efficiency was not sufficient. No credit was given to the industrial customer for taking out the old, less efficient boilers.

Estimated Costs

The industrial customer's cost to overcome these barriers was estimated at $2 million.

Distributed Generator's Proposed Solutions

The distributed power equipment supplier suggested that the process would be improved significantly if regulators could develop a national air standard for

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these sources to reduce the confusion and difficulty inherent in the current approval process. In addition, larger project developers consistently recommended that uniform standby rates be approved. Another benefit of distributed generation is the ability to reduce peak demands on utility systems; yet, distributed generators do not receive credit in standby rates for this benefit.

Case #2 — 21-MW Cogenerating Gas Turbine Project in Texas

Technology/size	Natural Gas Cogeneration Four 5.2-MW units
Interconnected	Yes
Major Barrier	Regulatory—Discount Tariffs
Barrier Related Costs	$1,000,000
Back-up Power Costs	Not Known

Background

An industrial customer contracted with a distributed generation developer to build a 20.8-MW gas turbine cogeneration plant at its Texas production facility. Two of the 5.2-MW gas turbines were started in August 1999, and two more were brought on-line in September 1999. Each unit had a synchronous generator and a 100,000-lb/hr boiler on heat recovery to achieve 92 percent thermal efficiency. The turbines run continuously to reduce the plant's peak demand and energy use. The customer decided to interconnect the turbines in parallel operation to the grid to provide voltage stability while starting up 1,000 hp motors and other large plant loads.

The developer believed the local utility tried to stop the installation at every turn with delay tactics and reduced rate incentives. The industrial customer signed a reduced rate contract in 1996 or 1997 because of short-term financial savings, but recently bought itself out of the contract at a cost of approximately $1 million to proceed with the cogeneration plant installation. The industrial customer's financial priorities shifted as its demand for steam increased over time. The customer also hoped to avoid the low voltage problems and outages it experienced on the utility grid during the peaks of summer. It finally elected to proceed with building the cogeneration plant without the utility's approval, ending what had been a ten-year delay since the inception of the project.

Next year, as its operating load changes, the industrial customer will be a net producer of energy and plans to sell it back to the grid. The utility plans to pay the industrial customer its avoided generation cost of about 2¢/kWh (fluctuating), which is lower than the customer's generation cost.

The industrial customer's primary benefits will be on-site generation of electricity and steam. However, the new gas turbines will provide a dramatic reduction in carbon dioxide and nitrogen oxides emissions by replacing the old, less-efficient and more polluting boilers. In addition, the industrial customer will enjoy higher power reliability than that provided by the utility grid.

Regulatory Barriers

Discount Tariffs

The greatest barrier to building this cogeneration facility was the utility's use of undisclosed discounts. The utility invoked this subsidy, offering confidential seven- to ten-year discount rate contracts to retain the customer who was intending to build its own cogeneration facilities. The utility's annual lost revenue from this cogeneration project will be in the millions for electric loads alone. This was the principal hurdle in this case. The industrial customer and the vendor were able to clear the air emissions hurdle easily because the air control board credited them for removing the old, less efficient boilers.

Case #3 — 15 MW Cogeneration Project in Missouri

Technology/size	Natural Gas Turbines—Cogeneration/15 MW
Interconnected	Yes
Major Barrier	Business Practices—Utility Delays
Barrier-Related Costs	$1,240,000 for Additional Equipment to Avoid Further Delays
Back-up Power Costs	Not Known

Background

This new 15-MW steam and electric combined-heat-and-power plant is located on the site of one of the first electric plants in the country—the source of

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power for the first electrified Worlds Fair held in St. Louis in 1904. The plant later added steam recovery to supply district steam heating to the city.

Through the 1980s the plant operated as a 70-MW peaking facility before its shutdown and sale by the utility. The current owner bought the site and installed two synchronous generators, each powered by a backpressure steam turbine and a new gas turbine.

The system achieves approximately 70 percent energy efficiency by combining steam production for district heating with electricity production. The steam turbines recover excess steam pressure from the steam system to power each generator to about 2.5 MW of capacity, and the gas turbines power the remaining 5 MW for a total of 15 MW of generation. In the winter with higher turbine efficiencies and more steam use the capacity rises to about 17 MW.

The project owner first approached the utility in June 1998 with a requested start date for the project of June 1, 1999. The utility required the same technical and operating requirements that it would apply to large utility-owned generation facilities 10 to 100 times the size, including the right to operate it as part of the utility system. The utility requested system upgrades the developer believed not appropriate or feasible for a small merchant plant. Similarly, requests for operating control of the units from the utility control center failed to recognize competitive market operation and relative size of the unit.

Although relatively large in terms of distributed power, the 15-MW combined heat-and-power facility here did not rise to the level of the one-percent metering error of the 2,000-MW coal plant operated by the utility forty miles away. When repeatedly confronted on the inappropriateness of the interconnection demands, the utility dropped some of the requirements to allow the project to proceed. Nonetheless, the technical interconnection requirements ultimately imposed added more than one million dollars to the cost of the project and delayed approval.

The developer also pointed out its perception of the differences between the utility project approach and a competitive market approach. For example, the utility was not amenable to overtime or additional expense to meet the interconnection deadline — even when the developer offered to pay for it. On the other hand, with respect to capital investment the utility many times proposed a higher-priced technical approach such as building a three-million-dollar substation, rather than looking at more effective lower cost options such as co-location and interconnection at the existing substation.

Further, the ability of the utility to recover its expenses in developing its interconnection policies was also felt to be unfair. In this case the nearby available substation requested by the developer for interconnection would have given any new generator direct distribution access to industrial and urban customers in a restructured market, without resort to transmission line reservation and fees. As ultimately configured, the interconnection steps the generation up to the transmission system and eliminates direct distribution access to such potential competitors of the utility.

Business Practice Barriers

Procedural Requirements for Interconnection

The interconnection approval was punctuated with cumulative procedural delays. For example, it was reported that the utility volunteered to take minutes of the meetings and then produced none over the course of many meetings. The developer eventually took over the responsibility for minutes after noting the delays. Telephone calls to the utility were reportedly met with repeated responses of "call next week." In what we found to be a common experience, midway through the process the utility changed representatives, resulting in weeks of no response, and ultimately direct dealings with operating line personnel were required to circumvent the impasse.

The developer also reported that several months before the June 1999 projected start date, the utility gave notice that a transmission line pole interconnection was near its yield point. A new, specific pole was required, which would take six months for delivery. The developer believed that the additional load of a short slack interconnection line was minimal compared to multiple spans of heavy transmission cable already on the pole. When asked for the new pole specifications for justification, the utility allowed interconnection with reinforcement to the existing pole. Similarly, with respect to what breakers would be required, the utility did not provide specifications. When presented with a breaker from another location, the utility claimed that it could not be used at the proposed site. When the developer presented the manufacturer's certification, the breaker was allowed.

The utility did not commence work until the last week of May 1999, far too late for completion by June 1, 1999. The utility's initial position was that no transmission hook-up could occur during the high-demand summer months, and thus interconnection would need to wait until fall. However, as capacity limits appeared as the summer peak approached, the utility agreed to interconnect, which it did by July 14, 1999. The utility accepted the power immediately at the PURPA buyback rate of 1.5¢/kWh, but restricted sales into the market to other buyers until remote reading meters were in place to allow the utility to monitor the owner's generation remotely. Those remote signaling meters were installed by July 23, 1999, at which time market sales began. The system has been in operation since that time.

Contractual Requirements for Interconnection

The developer asked for a draft contract at the start of the negotiations in June 1998. The first draft was provided in April 1999. Among the utility control provisions included in the draft contract was the right to take over remote operation of the plant when system conditions demanded. This and similar provisions, which had been common under the natural monopoly regulatory environment, were the principal subjects of negotiations, rather than one including the needs of merchant plant operation and market response.

The contract provisions required redrafting to recognize the shift away from utility ownership and control to market operation. For example, the utility cited its need for control of supply grid operations under an ISO, overriding competitive interests in the developer in meeting that supply need. The language that was ultimately adopted allowed dispatch of the plant in a system emergency, not otherwise defined, with the owner reimbursed for costs. The market value and payment for this generation are not otherwise defined. As indicated above, the utility's request for direct digital remote control of the merchant plant was ultimately negotiated down to remote meter access.

Technical Barriers

The developer believed that the technical requirements were also imposed to discourage the installation. The developer initially proposed tying into the utility substation located three blocks away from the project site. The nearby substation had existing duct banks already in place for underground interconnection, operated at the 13.8-kV generation voltage, and directly served downtown and industrial loads. For two months, the utility attempted to direct the project to a more distant substation through old feeder lines operating under a river flood plain not suitable for reliable access and operation. Moreover, the developer was concerned that the condition of the aging equipment at that substation would entail higher operation and maintenance costs for the life of the project.

When the developer refused the distant interconnection, the utility estimated a cost of $2.5 million to modify the nearby substation, claiming all breakers would need to be replaced to handle the capacity. The developer proposed co-location of new transformers at the same site to make use of interconnection and 13.8 kV access, but was refused. As a consequence, the developer was required to build a new substation with underground access and transformers to enter at the transmission level.

The utility quoted a cost of $3 million and two years to build the substation. The developer chose to build the new substation in six months, keeping to the June 1999 projected schedule, at a cost of $1.7 million — more than $1 million less than the utility quote and $0.8 million less than the utility estimate for direct interconnection at the nearby substation. However, the required cost was $1 million dollars more than the preferred nearby 13.8-kV access that the developer believed would have been acceptable with new transformers.

Finally, after completion of the substation, the utility tied in the three-phase feeder lines with system protection relays on each end with costs to be billed to the developer based on a good-faith estimate of $240,000.

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Utility Position

The utility representative stated that the utility currently had distributed power as well as independent power producer projects in its service territory. The representative stated that the utility had established contact procedures and personnel to process distributed power applications. The utility accepted Underwriters Laboratories (UL) and Institute of Electrical Engineers & Electronics (IEEE) certified equipment for interconnection, but also test trips verification relays as well. The utility also required installation of their own remote disconnection control and the customer was responsible for all safety testing expenses.

The utility did not have any rate reduction programs for customers who sought rate relief, but did have an experimental tariff in place to shave peak loads on high load days. The experimental tariff can reduce the demand charges for the customer reduction of peak loads.

The utility charged no exit fees or Competitive Transition Charges (CTCs) in Missouri, but did have a standby service charge for customers who chose to self-generate to reduce their demand and energy use. Customers who chose to generate excess capacity and sell it back to the market, must either sell this power directly to the utility at a standard buy back rate or pay an uplift charge to move the power to the transmission system, as well as transmission charges.

Case #4 — 10-MW Industrial Cogeneration Project in New York

Technology/size	Dual Fuel Combustion Turbine (CT) and Reciprocating Engines (Recip)—Cogeneration 3 MW CT: 3-2.2 MW Recip
Interconnected	No
Major Barrier	Regulatory—Discount Tariff
Barrier Related Costs	Not Known
Back-up Power Costs	Not Known

Background

A distributed-power equipment supplier in New York sought to install a cogeneration facility for an industrial client. The client wanted to operate this 10-MW plant on a continuous basis, fully disconnected from the grid with a full back-up power system. This facility included a 3-MW duel fuel combustion turbine with a 200-kW back-pressure turbine. It also had three 2.2-MW duel-fuel reciprocating engines that supplied 20,000 lbs/ hour of 400-psig superheated steam for heat recovery. The distributed power equipment supplier worked with the client for two years to develop plans for the proposed cogeneration facility.

The local electric distribution company was aware of the negotiations between the customer and the equipment supplier and wanted to retain the customer and its $6-7 million per year revenue stream. The utility made a total of 25 separate proposals over the two-year period to undercut the offers of the distributed power equipment supplier. The local regulatory agency also became involved in the effort to keep this customer on the grid. The special discount rate contract the utility and regulatory agency finally offered the customer undercut the rate of return and guaranteed savings offered by the distributed power equipment supplier, causing the customer to abandon the project.

Project Benefits

The industrial customer would have benefited from the proposed cogeneration plant by using the electricity and steam produced on site for its entire load, heating, preheating hot water, and other industrial processes. It would have been able to produce its own electricity and steam at a much lower cost than its pre-discount avoided purchase price. The environmental benefit of using cogeneration at this facility would have been a combination of replacing the old high-NO_x output boilers with highly efficient gas turbines and displacing the fossil-fired electric load and associated transmission losses. The developer noted that the loss of these benefits will be compounded over time as the current system continues to pay for less efficient higher-pollutant technology in place of the cleaner combined-cycle generation technology.

Regulatory Barriers

Discount Tariffs

The primary barrier to the success of this project was the combined effort between the local power distribution company and the power transmission company to undercut the 20-year power rate guaranteed by the distributed power equipment supplier. It was reported that the utility had initially tried unsuccessfully to dissuade the customer from building the cogeneration plant on its own for at least a year before involving the regulatory agency. The utility was able to use its discount tariff to offer a deeply discounted three-year rate incentive to the customer. This tariff allowed the utility to offer lower rates to retain an electric customer under the "Power for Jobs" program approved by the New York State Legislature. This program provides lower cost electricity to businesses and not-for-profit organizations that agree to retain or create jobs in New York State.

During the bidding process, the customer became aware of the utility's determination to retain its load. The customer then used this leverage to bid the utility and the distributed power supplier against one another to negotiate the best possible deal for its power. In the final hours of contract negotiation between the equipment supplier and the customer, the utility presented the combined offer it had arranged with the regulatory agency to persuade the customer to abandon the cogeneration project.

The regulatory agency further blocked the co-generation project by approving transport rates for natural gas to the proposed cogeneration facility (through its gas distribution system) that were nine times higher than the utility charged itself.

Distributed Generator's Proposed Solutions

The developer recognized that, for some customers, this case scenario provides them special benefits—discounts not ordinarily available in a monopoly market. They enjoy long-term discounted electric rates with the utility until the incentive plans expire, then they either renegotiate a better contract or reawaken the cogeneration facility plans. The competitive supplier, however, felt that it had to confront monopoly market power in collaboration with the regulatory authority in a kind of public subsidy of the status quo.

Utility Position

The utility was contacted and answered several questions regarding its position on distributed power and related issues. The following information was as related by the utility representative.

The utility was concerned that no acceptable national interconnection standard currently exists and expects a national standard to simplify matters. At this time, the utility used Appendix A of NY state requirements. The utility stated that complications existed because the grid and all protection systems were initially designed for unidirectional power flow, not bi-directional or multiple outlying sources.

For installations under 300 kW, the utility was most concerned with anti-islanding—ensuring that the system would auto disconnect during periods of instability and fluctuations. For systems larger than 300 kW, especially above 1 MW, the utility was concerned about having control over the distributed power source so that it could remotely monitor all facets of customer generation and load. The utility believed that it must be able to disconnect the generator, if necessary, or change the operating characteristics during frequency and voltage fluctuations.

The utility required an engineering review for interconnected distributed power systems and type testing of the components involved. The utility had standard interconnection agreements for both large and small generators.

Case #5 — 5-MW Hospital Cogeneration Project in New York

Technology/size	Natural Gas Cogeneration/ 5 MW
Interconnected	No
Major Barrier	Regulatory—Backup Tariff
Barrier-Related Costs	Not Known
Back-up Power Costs	$200/kW-year.

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Background

A distributed power equipment supplier in the Northeast sought to install a cogeneration facility for a hospital client. The client wanted to operate this 5-MW plant on a continuous basis to provide base-load generation and cover foreseeable demand peaks. The facility was to include a 5-MW dual-fuel combustion turbine. This turbine was to supply a heat-recovery steam generator producing 70,000 lbs/hour of 200-psig superheated steam. The hospital intended to retire several old boilers by installing the new cogeneration plant, as well as use the low-grade steam for absorption chilling. The small plant size and reliability needs of the hospital required parallel operation to the grid. Ultimately, the high charges levied by the utility for backing up the full plant capacity caused the hospital to abandon this project. The utility would have lost an estimated $850,000 per year in revenue from the customer.

This hospital would have benefited from the proposed cogeneration plant by using all the electricity and steam produced on site for base load, heating, preheating hot water, and driving absorption chillers. It would have been able to produce its own electricity and steam at a much lower cost than its avoided purchase price had the high standby charges not been levied. Finally, there would have been a significant environmental benefit from the increased efficiency of using cogeneration at this facility, resulting from a combination of replacing the old heating boilers with highly efficient gas turbines, using the otherwise wasted low-grade heat, and displacing other fossil-fired electric load and associated transmission losses.

Regulatory Barriers

Back-up Tariff

The primary barrier to the success of this project was the back-up tariff imposed by the local utility. The utility required a reservation of the full 5 to 6 MW of plant capacity for the entire year at a cost of $1 million, even though the hospital would have provided a benefit to the utility system in the form of back-up capacity for use by the utility. (The power system design would have allowed the hospital to run independently from the grid during local power outages or capacity limits.) The utility was unwilling to offer a partial credit for the back-up power system in place at the hospital.

Environmental Permitting

The cogeneration plant at this hospital would have been classified as a "major source" of environmental pollutants. The air permitting process for a "minor source" cogeneration facility can last six to nine months, and for a "major source" the process can last up to two years. Many customers and vendors seeking to self-generate are not willing to invest the time and financial resources in the permitting process itself and the resulting regulations for the installation at their facilities.

Estimated Costs

The annual back-up tariff was to be $1 million dollars, which was expensive for this project and expensive on a capacity basis (~$16/kW-month). The costs of the environmental testing and permitting process were also expected to be quite high—although more difficult to estimate because the cost is primarily the time spent to address the requirements.

Distributed Generator's Proposed Solutions

The equipment supplier that we interviewed for this case study suggested that the industry regulators adopt output-based emission standards to recognize the benefit of cogeneration in combining generation process efficiency and utility as well as reducing fuel consumption and displacing the pollutants of inefficient boilers. Such an approach would not only recognize the efficient production of electricity from the turbine generator, but also the utility of the combustion waste heat as it is applied and conserved in its facility. Without this evaluation system, the customer is evaluated on the basis of total NO_x emissions for the year and emissions at short test intervals to the power produced, without crediting for high efficiency provided by the steam and heat recovery processes.

Utility Position

The utility was contacted and answered several questions regarding its position on distributed power and related issues. The following information is as related by the utility representative.

The customer is not prohibited from producing power as long as it passes emission standards and meets safety requirements. The utility's Distribution Engineering Department must approve the system plans. The utility is only concerned with the safety and reliability of the interconnection and the grid itself.

Case #6 — 1.2-MW Gas Turbine in Texas

Technology/size	Natural Gas Aero derivative Turbine/ 1.2 MW
Interconnected	Yes
Major Barrier	Business Practice—Full Requirements Contract
Barrier-Related Costs	None
Back-up Power Costs	None

Background

The customer in this case was a distribution co-op that was provided wholesale power from two G&T utilities. The co-op had not previously owned any generating assets. The cost of generation and transmission was $6.54/kW-month for demand and 3.4¢/ kWh for energy from the G&T contracts. In addition, there was a 65 percent demand ratchet for 12 months. Its typical summer peak demand was 170 MW; thus, its peak demand for the next 12 months was 110 MW (65 percent of 170 MW) even though its base load was 40-50MW.

In areas of relatively flat demand, this would not be a problem; however, this distribution utility experienced its peak load only during a six- to twelve-week irrigation season. Load could change very rapidly as heavy rains moved through the area because the majority of the load was from irrigation pumps and equipment. Thus, 90 MW of demand could disappear within one hour on a system with a 40- to 50-MW base load and a 170-MW peak.

As a result, the distribution utility began to consider ways to reduce the peak load in the summer months. In addition, voltage regulation was an issue because of the nature of its customer load. The distribution utility must maintain a 95-percent power factor, although it strives for 100 percent. The distribution utility believed that adding generation to its grid would help keep its power factor closer to unity and would increase grid stability.

The utility was under a Full Requirements contract with its G & T's, which did not allow it to generate power as a wholesaler. It had PURPA (the Public Utility Regulatory Policies Act of 1978) qualified facility (QF) status, but it would have preferred independent power producer (IPP) status where the distribution company would be able to produce and provide power back to the G&T at more acceptable buy back rates than allowed for QFs. Thus, the distribution utility chose to become a partial requirements wholesale customer by year's end. The distribution utility will combine several power supply contracts, exercise a load management program, and purchase some peaking requirements from the market. Meanwhile, it is studying how distributed power could augment or enhance its load management program and control risk management.

The distribution utility did have a demand peak shaving program, including any-time-of-day interruption and every-other-day interruption. This allowed the farmers to select interruption schedules for specific days of the week. Typical savings of around 10 percent were provided to customers as rebates at the end of the year. However, the savings varied from year to year. Exact customer rebate amounts were not specified when a customer joined the program. The G&T utility allocated a specified amount to be rebated to customers each year. If more customers entered the program, the rebate might be lower.

To begin efforts to install its own generation, the distribution utility experimented with 130-kW installations independent from the grid. The installations were able to produce the distributed power cheaper than the generation and transmission costs at 3.3¢/kWh, even with natural gas generation. These projects were separate from the specific 1.2-MW project discussed in this case study, but it is noteworthy that the distribution utility installed other projects as well.

To increase these efforts, the distribution utility started a project that was funded by the Gas Research Institute with assistance from its gas supplier and Texas Tech University. This project was a skid-mounted natural-gas turbine based on a helicopter engine with a capacity of 1.2 MW. The engine was said to have excellent dynamic capability from full load to zero to full load again in a very short period of time (about a minute).

The generation was synchronous with solid-state controls specifically designed for distributed applications. The controls were provided as a package for $55,000, including a 3000-amp bus, buses to control the breakers, and relays, which communicate with both the unit and the distribution utility. The unit side relays allowed for a soft load (slower ramp up and cool down) and the relays on the utility side provided for protection of single-phase faults, phase-to-phase faults, and the identification of zone faults. It also allows remote operation by the distribution utility. In addition, software provided by the control supplier as part of the package monitors the kW, kWh, KVA, power factor failures, and reasons for power failures. With these controls, the size of the unit could be increased to 2 MW without any additional modifications.

The unit was interconnected parallel to the grid two-thirds of the way out on a radial distribution line serving homes and farms in the region. There were 250 meters on the line, mostly three-phase, and 20 percent of the customers were residential. This particular distribution substation could experience daily loads as high as 10 MW during irrigation season and as low as 1 MW other times.

The project started operation in September 1999. The unit will initially be operated for 2,000 hours for testing purposes and then would be able to operate when needed in the summer

From a technical standpoint, the installation went smoothly under very detailed technical specifications from the utility for installation of the generator. The distribution utility was required to provide a protective breaker at the 69 kV line to feed the 12 kV distribution line from the G&T.

Project Benefits

In addition to reduced peak demand, the distribution utility installation also stabilized the grid and improved the power factor with this project. The unit was installed to maximize the stability of the grid. From a global standpoint, there were avoided transmission and distribution costs, especially when considering the varying load on the circuit.

In addition, the project can generate power at a cost of 4.5¢/kWh (1.5¢/kWh for operations and maintenance costs and 3.0¢/kWh for fuel). Power costs to the distribution utility were higher when supplied by the G&T.

During the irrigation off-season, some of the power flows back to the substation from the distributed power installation and out the other three distribution lines on that substation. As discussed above, the distribution utility was interested in supplying part of its own generation. The utility was operating under the philosophy that its generating assets should be as liquid as possible in order to be flexible and allow for change in the future as the customers needs change. The distribution utility expected to invest $80 million over the next 10 years to improve and build a flexible distribution system.

Business Practice Barriers

Contractual Barriers to Interconnection

The key barrier for the distribution utility is that it is currently under a Full Requirements contract as discussed above and cannot become a wholesale power producer under this contract. Selling to the G&T utility produced only 1.7¢/kWh for energy as against a cost to generate of 4.5¢/kWh. The Public Utility Commission (PUC) was aware of the situation, and as a result of PUC involvement, the G&T utility is considering a potential incentive rate instead of the 1.7¢/kWh rate that will apply only to this project. The unit started up in September, although a higher rate had not yet been negotiated and the project would only be allowed to sell to the G&T at the 1.7¢/kWh. The 1.7¢/kWh buyback rate was a historical rate based on wind projects that have been installed in the past.

Fortunately, because the distributed power developer was the distribution company, there were no standby charges associated with the project. However, if the unit was not allowed to generate revenue by selling power back into the grid at a reasonable rate during non-irrigation peak times, further projects would not be economic. Since the distribution utility would like to install at least 10 MW of generation at a weak point in its grid system, this becomes a critical issue.

Distributed Generator's Proposed Solutions

The key solution would be for the distribution utility to be allowed to become a wholesale generator that can sell its power on the wholesale market. The distribution utility is taking a local and flexible approach to resolving grid stability problems and would prefer to continue to install distributed power locally. However, the contractual and tariff issues must be resolved before the effort to install distributed power can continue.

Case #7 — 1-MW Landfill Gas Project in Massachusetts

Technology/size	Landfill Gas Reciprocating Engine/ 1 MW
Interconnected	No
Major Barrier	Regulatory—Transmission and Distribution Tariffs
Barrier-Related Costs	Not Applicable
Back-up Power Costs	Not Known

Background

A city in Massachusetts contracted with a developer to investigate operation of a 1-MW reciprocating engine and generator on recovered landfill methane (currently being flared from the community landfill) to supply part of the 2 MW local municipal load. The municipal load delivery points were between zero and eight miles from the landfill generation site, connected by a distribution line operating at 13 kV. The proposed project had not been installed yet.

With this installation, the community would be able to meet half of its electrical needs by utilizing a currently wasted resource. The power would be generated at or very near the point of use, would be low cost, would provide stability to the distribution line, would reduce the losses in the transmission and distribution (T&D) network, and would provide enhanced capacity on the regional transmission grid.

Regulatory Barriers

Independent System Operators (ISO) Requirements and T&D Tariffs

The most significant barriers to installation of this project were the tariffs for transmission and distribution. Even though the proposed project would be serving local loads within a single distribution area, it would still be subject to the following tariffs under the following current regulatory structure:

- Local distribution tariffs
- Full regional transmission costs
- Penalties for losses
- Operating charges under ISO rules.

An "uplift tariff" charge for wheeling the power through the local distribution and transmission system to the regional pooled facilities was assessed. The uplift tariff applied was the transmission company's non-ISO tariff: "Open Access Transmission Tariff for Transmission and Ancillary Services Not Provided Under the New England Power Pool (NEPOOL) Open Access Transmission Tariff." It was to be assessed regardless of the fact that the power was generated and used locally. For this project, the transmission company might make an exception and the tariff might not be assessed. However, for future projects these issues have not been addressed and other similar projects could be assessed an uplift tariff. In years past, this tariff was approximately $5/kW-month plus losses of eight percent or more (discussed below).

The transmission company also had an alternative "point-to-point" transmission tariff, which required interval metering and telemetering of data to NEPOOL, which made it more expensive than local distribution system service. The "point-to-point" transmission service was $1.79/kW-month for both firm and non-firm service.

Losses were assigned to the retail load on the assumption that they were being served from the Pool Transmission Facility (PTF) level, and required five to nine percent more generation delivered than load served depending on the local distribution company and interconnection voltage of the customer served (the higher the service voltage, the lower the losses applied). Local loads served by local generation (within the same distribution system) were assessed the same level of losses as loads served by generation connected to the NEPOOL pooled transmission facilities—even though part of their competitive advantage was reduction or elimination of such losses. In other words, capacity on the distribution system serving local loads, which reduced transmission loads into that system from NEPOOL were assumed to experience the same losses as capacity actually being carried from outside the distribution system. There were no provisions for credit or value for reduced losses on the distribution or transmission systems and reduced power import as a result of distributed power.

Estimated Costs

For the specific case considered here, where most of the customers were small- to medium-sized municipal end-users, the losses assessment equaled nine percent of the load served.

In addition, distributed power was charged additional "assumed" losses from two to eight percent depending on the interconnection voltage. In this case, the calculated loss would be around five percent, thus the total charged losses for the project would be 14 percent.

Distributed Generator's Proposed Solutions

Currently in the ISO-NE settlement system, distributed power less than 1 MW in capacity cannot be readily accounted for. As a result, the local supplier would need to attach the accounting to the current system supplier (or a system supplier) and treat this size class of distributed resources as a "negative load," or adjustment to the main account. As a result of this negative load treatment, a distributed resource actually receives credit at the PTF level for metered generation plus losses (i.e., a 900-kW facility receives credit for an extra 54 kW for losses avoided). This treatment is very much the exception rather than the rule, and ISO-NE is apparently considering whether to retain this treatment of small resources as it moves forward. The situation has not been resolved.

The state and PUC need to address the procedures and charges by which distributed power can enter the wholesale T&D market consistent with the smaller size and more local system impacts.

Utility Position

We contacted the utility several times to obtain its position on distributed power and related issues. We were directed to other individuals with each phone call, and the correct individual was never identified.

Case #8 — 750-kW and 1-MW Diesel Generators in Colorado

Technology/size	Diesel Reciprocating Engines for Standby Service/ 1 MW
Interconnected	No
Major Barrier	Business Practices—Not Allowed to Interconnect and Operate Equipment
Barrier-Related Costs	Not Known
Back-up Power Costs	None

Background

Certain regions in the Rocky Mountains are known for rugged terrain and remote access, as well as proximity to national forests and wilderness areas. In recent years, the population and recreational use of these areas has increased and, as a result, the amount of energy and capacity required for the region has increased. In the winter, the community in this case study required 26 MW of peak capacity, projected to increase to 40-46 MW by 2019. Summer peak was half that amount.

A large industrial user and a commercial user, at the request of their local distribution utility, sought to reduce their peak load by installing peak-shaving capacity and by backing down power during peak periods. These customers were prompted to investigate peak shaving by virtue of a "Three-Phase" incentive rate structure from the distribution utility. The tariff included a coincident peak demand charge of approximately $14.00/kW-month and a non-coincident peak demand charge of approximately $7.00/kW-month. The charge for energy was reduced to $0.033/kWh under this demand charge tariff.

The standard customer tariff from the distribution utility with demand metering is $9/kW-month for all kW over 20 kW per month. The standard tariff for energy was $0.047/kWh. Under this arrangement peak shaving with on-site generation could significantly reduce demand charges.

Initially, the industrial user was approached by the distribution utility to install back-up and peak-shaving capacity at its facility. The facility already had a small back-up generator. The utility was instituting a peak-shaving incentive program that would allow it to reduce its overall peak wholesale purchases under its all requirements contract with the G&T. A letter from the distribution utility to the customer outlining the rate tariff for the pilot program initially described a rate tariff of $3.50/kW-month for non-coincident peak, $14.62/kW-month for coincident peak, and $0.048/kWh for energy. In November 1995, the customer purchased and installed a 1-MW diesel generator in accordance with the distribution utility program.

The utility imposed control requirements. The generator was equipped with an automatic transfer switch, allowing the generator to be started and transferred from a remote location. The distribution utility notified the plant 15 minutes before each peak shaving event. The utility starts and stops the generator remotely via a signal sent directly over the power lines. The generator was operated a maximum of 10 hours per month, and only during times requested by the utility. The transfer switch does not allow parallel operation.

The commercial user was also approached by the utility to enter the incentive program. The incentive program was already in place at the other industrial facility described above and the rate tariff was published. The commercial facility typically had a peak load of 1.2 MW but could reduce that load to 700 kW at any given time using load shedding and scheduling techniques (primarily for large chiller units).

Business Practice Barriers

Procedural Impediments to Interconnection

The agreement between the industrial facility and the utility began as an informal verbal agreement. At the time, an incentive rate tariff was not actually published by the utility. In exchange for installation of the generator, the utility's letter offer stated the industrial facility would be eligible for the $3.50/kW-month incentive rate during non-coincident peak demand hours. Based on that representation, the customer purchased a generator in November 1995 at a cost of $350,000. The customer never entered a more formal contract with the utility. In March 1996, another utility representative approached the customer with a second proposal and a non-coincident peak rate of $6.72/kW-month. The reason offered for the rate change was the settlement of the distribution utility's rate case that included less favorable rates. Notwithstanding the substantial investment based on the lower represented rate, the utility instituted the higher demand charge incentive tariff.

Even so, there was a delay in implementing the less advantageous tariff, which took effect in June 1996, six months after the customer's capital investment. The savings for the first period from June 18 to August 6, 1996, was $5,783.

Not Allowed to Operate in Parallel

The industrial customer made an investment in a 1-MW generator on a site with a monthly peak demand typically between 250 to 350 kW. Even with planned expansions, the monthly peak demand of this customer will not exceed 500 kW. The customer sought to operate the generator in parallel with the utility system to provide capacity during critical peak periods. This was not allowed by the utility. The commercial customer likewise had a 750-kW back-up generator. It also sought to operate the unit in parallel to the utility system. However, the utility did not allow for parallel operation and prevented use of either generator for peak shaving capability, except as controlled to operate by the utility.

Reduced Peak Shaving Under Utility Control

Changes in the program reduced savings several times. The distribution utility uses remote control to shed the customer load when it elects to do so. The savings to the customer result only when the load shedding coincides with the G&T system peak, which the distribution utility does not know until after the fact. The utility has control over the decision to shed peak demand from both the industrial and commercial customers. It is not obligated to reduce the load; therefore, these customers are billed higher coincident peak demand charges if the utility elects not to shave the peak. The choice is the utility's, thus these customers are not able to maximize their investment return.

Originally, the commercial customer was saving as much as $7,000 per month. After several months of

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operation the savings decreased until the bill reflected only a $2,500 per month savings. The customer approached the utility about this change. The explanation offered was that the G&T changed its peak shaving policy to the distribution utility to require a 21-MW peak before it allowed peak shaving. The change implemented by the G&T significantly reduced the benefits of peak shaving to the distributed utility, which in turn adjusted its peak shaving control to reduce peak shavings to the customer.

Distributed Generator's Proposed Solutions

The ability to operate in parallel within fairly (to the utility and the customer-owned facility) designed tariffs would allow the customers to maximize the benefit of the generating capacity in the region. The modifications required to allow parallel operation of the industrial on-site generation in this example would cost approximately $40,000 and would provide the ability to reduce the utility's peak load by another 0.75 MW, a modest price for this order of capacity addition.

Properly operated to reduce peak-demand charges, the full amount of peak-shaving generation could often pay for itself with only a few hundred hours of operation at times of peak demand. The utility's preliminary steps toward peak-shaving generation at several key facilities in this case study, and the proposed incentive through reduced demand charges, appear to confirm its conceptual agreement with such potential benefits.

3.2 Individual Case Study Narratives for Mid-Size Distributed Power Projects (25 kW to 1 MW)

Several new distributed power technologies have entered the market in the 25-kW to 1-MW system size in the last decade, including fuel cells, mini- and micro-turbines, small wind-turbines, and utility-scale solar projects. Twenty-four of the 65 case studies conducted were in this range. These systems have begun to open commercial markets for the mass production of distributed power systems to serve specialized customer applications. The "green" demand emerging within competitive markets for cleaner, renewable, and combined heat-and-power options often falls within this size range. However, the distributed power solutions for uninterruptible back-up supply, peak shaving, and commercial energy account management also face barriers that some argue hit hardest in this size range.

Large enough to compete for key commercial energy accounts, distributed power systems in this size range and larger must compete against traditional one-size-fits-all utility service. These systems now offer power choices that can be cleaner than the grid, cheaper than the grid, and more reliable than the grid in particular applications. As a result, increasing numbers of vendors and customers are approaching distribution utilities for interconnection.

Unfortunately, our study suggested that the current environment can be unpredictable, uncertain, and in many cases hostile to the new customer choices offered by these technologies. Such a business and regulatory environment can create significant barriers for particular projects. We believe that these barriers are unnecessarily blocking the emergence of a more substantial commercial market for these distributed power technologies.

These 10 cases were chosen from the 24 mid-sized distributed power examples as a representative cross section of the barriers encountered. The selected case studies organized by their size are as follows:

- 703-kW Tri-Generation System in Maryland.
- 260-kW Natural Gas Generators in Louisiana
- 200-kW Fuel Cell Demonstration Project in Michigan
- 140-kW Reciprocating Natural Gas Engine-Generator in Colorado
- 132-kW Solar Array in California
- 120-kW Propane Gas Reciprocating Engine for Base Load Service at Hospital
- 75-kW Natural Gas Microturbine in California
- 50-Watt to 500 kW Wind and PV Systems in Texas
- 43-kW Commercial Photovoltaic System in Pennsylvania
- 35-kW Wind Turbine in Minnesota

Case #9 — 703-kW System in Maryland

Technology/size	Backpressure Steam Turbine Supplied by Waste to Energy Facility/ 703 kW
Interconnected	Not connected as of the Fall of 1999.
Major Barrier	Business Practices—Utility Delays
Barrier-Related Costs	$88,000
Back-up Power Costs	Not Known

Background

This 703-kW generator was installed in a downtown office building to supply building electric loads and air conditioning. The generating unit operates on steam purchased under a long-term contract from a waste-to-energy facility located at the municipal waste site one mile away. Since the mid-1980s the steam has supplied the building heating and hot water loads. The back pressure steam turbine is driven by the high steam pressure otherwise lost in the heat recovery process at the site.

This innovative commercial-scale configuration thus operates on renewable waste energy at low cost, with exemplary operating efficiency. By supplying hot water, cooling, and electric loads from the same steam supply, the system achieves more than 88 percent efficiency. Frictional and mechanical losses account for most of the remainder.

The generation is synchronous and intended for parallel operation behind local distribution system protection at a more than 90 percent capacity factor of about 8,000 hours per year. The back pressure electric turbine is sized to supply most of the building electric and chiller load, with supplemental electricity purchased from the utility, and no export or sale of electricity to the grid. Two electric-driven coolers installed in the building in March 1998, originally intended to run off the on-site co-generation unit, have been running on utility-supplied power.

The generator is installed and has been ready for operation since September 1998. After significant expense, the original technical interconnection requirements were met. The initial technical requirements were followed, however, by unanticipated additional demands for operational control by the utility. To minimize further delays, the project owner agreed to the Consolidated Edison guidelines, which required the installation of additional system modifications, monitoring equipment, switchgear, back-up systems, and safety equipment. These new changes were completed by the spring of 1999; however, the unit was still not operational as of September 1999. As a result, 703 kW of available installed capacity remained unused, even during record power demand and power shortages in the summer of 1999.

Business Practice Barriers

Processing Requests

The project owner first contacted the utility in late 1997, and negotiations have been underway for nearly two years without resolution of interconnection issues. As soon as the development contract was in place, the developer provided the utility with notice and requested information, cost estimates, requirements, specifications, and schedules. It also provided equipment specifications and building specifications. The project owner started this process early with the goal of avoiding operating delays.

From the project owner's perspective, the delays are attributable to the absence of utility procedures for handling interconnection requests, and from the absence of any established approach for resolving interconnection disagreements. The parties had meetings scheduled every few weeks, but little progress was made. Large numbers of utility representatives, often ten to twelve at a time, made it difficult to schedule meetings and to determine who was responsible at the utility. There was apparently no viable remedy available from the PUC to handle delays.

Operational Requirements for Interconnection

After the project owner complied with the initial technical requirements for interconnection, the utility imposed a set of operational requirements not previously raised. This imposed restrictions on the project owner's ability to decide when and how to operate the generating facility. For example, one operating parameter required that the system be shut down if a feeder to the building goes out and gave the utility further control over the operation of the system. Utility control of this small system was contrary to the primary purpose of the system to optimize energy production for the customer location. Shutting the system down when part of the grid is out eliminates the secondary customer value of reliable back-up power. The additional operating demands were unexpected. The expenditures for interconnection and safety equipment were incorporated for the purpose of allowing the building system to operate independently of the grid when such operation was beneficial to the utility. There are at present no standards or references for determining standard practice or reasonable operating parameters. The utility requested the right to control how and when to run the equipment, as it might for a much larger, utility-owned resource.

Technical Barriers

Network Protection Requirements

Electric service to the building is provided by a network distribution system, which serves the City of Baltimore. Rather than a radial feed from a local distribution substation, the building is served by three 13.8-kV distribution feeders. Accordingly, the system requires protection for the network rather than protection for a single radial feeder.

Perhaps because this was the first distributed-power system of its type in Baltimore, the utility appeared to be unfamiliar with network interconnection issues and expressed concern that reverse flows within the network could create system outages over a broader area. The utility requested a custom engineering design to protect the network from the installation. In a network distribution system, protective measures seek to isolate one feeder at a time to allow the network to continue to operate through the remaining feeders. The project owner paid for $44,000 in fees incurred by consultants for the utility to design the requested network protection. Upon completion, the utility expressed dissatisfaction with the result, and the effort started anew.

The consultants then suggested that the project adopt existing guidelines developed by Consolidated Edison in New York City, which also uses a network distribution system. These guidelines were burdensome and expensive given the size of the installation, but were presented by the utility consultants as a way to speed up the interconnection process. To minimize further delays, the project owner agreed to the Consolidated Edison guidelines, which required the installation of additional system modifications, monitoring equipment, switchgear, back-up systems, and safety equipment.

Estimated Costs

The direct costs incurred in meeting the interconnection standards were $88,000. These costs do not include costs associated with the delays, including the loss of energy savings and return on investment.

Utility Position

The utility was contacted and answered several questions regarding its position on distributed power and related issues. The following information is as related by the utility representative.

The utility currently has established contacts and standard procedures in place to deal with distributed power applications, but wishes to improve on these procedures and be proactive rather than reactive on this issue. The utility anticipates growing interest in distributed power.

The utility recognizes and accepts the UL label, but will test at the customer's expense any "custom" packages, which vary from its preferred packages. The utility has engineers who are involved in ongoing IEEE activities to develop national standards.

The utility noted that distributed power issues are currently being reviewed by the state regulatory commission, and changes to its program are likely as a result of these discussions. For example any customer (with an installation smaller than 80 MW) who has a contract in place by September 1999 can avoid any stranded-cost charges in the future. Future customers will likely be charged for stranded-cost recovery, although the utility does not know at this time what these stranded costs will be. Legislation may result in individual contracts with applicable fees or customer specific cases to recover recent equipment upgrades that would no longer be recoverable in the rate base.

conditions for "Customers who have installed equipment and self generate their own primary electric services." The ordinance prohibited parallel operation altogether and established a Standby Service tariff not previously in existence, which included demand and energy charges. The demand charges equaled $10.00 per kilowatt-month for the first 15 kW and $8.00 per kilowatt-month above 15 kW with a twelve-month ratchet at 75 percent of that charge. The ordinance included a flat monthly fee for transformers installed, based on the size calculated at $2.00 per KVA. Finally the ordinance included power-factor minimums for any customer taking service and included rate increases for lagging power factors within the minimum acceptable range.

When contacted regarding the proposed installation, the city provided an "Example Standby Customer's Monthly Bill" to illustrate the bill amounts that would result to the facility for supplemental and standby power following installation of the on-site generation. The standby rate resulted in a supplemental bill, for one-third the power previously consumed, roughly equal to the current bill for full use. The standby rate applied to full supply during a month in which the generators were not operated. It was about double the current bill and added continuing monthly demand charge for the next 11 months.

The new standby service ordinance resulted in the project being abandoned, with losses borne by the vendors.

Regulatory Barriers

Ordinance Prohibiting Parallel Operation

The developer's investigation into the origin of the new ordinance prohibiting parallel connection of self-generation revealed that the city's wholesale supplier instructed the city to block the proposed customer self-generation. The wholesale supplier, a local G&T Cooperative, reportedly informed the city that self-generation threatens the future of the utility and would result in higher wholesale rates to the City. The G&T apparently drafted the new standby service ordinance to block the proposed self-generation, and the City passed it to stop the project, which it did. At the same time, the city's consulting engineer was given notice that he could no longer serve as the city engineer if he provided any private consulting to the project.

Standby Tariff

Using the demand and energy charges contained in the new Standby Tariff, the city calculated the truck stop's utility bill for 25,000 kWh of supplemental power under the newly enacted tariff at $5,400, as compared to a standard bill for 80,000 kWh of $6,000. The increase resulted from calculation of demand and energy charges imposed by the standby service tariff. The higher tariff is applied to the load based on the existence of "installed equipment," independent of load profile. A customer with equivalent energy usage and profile without such equipment on-site would presumably continue to receive bills under the standard tariff.

The stand-by tariff adopted resulted in a significant addition to the projected cost of electricity. This offset the energy savings from on-site generation, and thus rendered the project uneconomic.

Estimated Costs

The actions taken by the city after its initial approval resulted in project losses being borne by the vendors, which included the engine supplier, the gas supplier, the operations control vendor, and the project contractor. The time of each, valued at $50 per hour, amounts to losses in excess of $10,000. Also, based on initial city approval, the project contractor had purchased two new engine-generator combinations, one of which was already on site. The contractor expended more than $100,000 in purchasing the equipment, some portion of which will be recovered by reassembling the systems for other installations.

In addition, the customer lost the energy savings that could have been realized with self-generation. A comparison of energy costs from on-site generation with the retail utility price indicates a loss on the order of $5,000 per month.

Utility Position

The utility was contacted regarding their position on distributed power and the proposed project. The utility representative responded that the utility was not interested in answering questions.

Case #11 — 200-kW Fuel Cell Demonstration Project in Michigan

Technology/size	Fuel Cell/ 200 kW
Interconnected	No
Major Barrier	Regulatory—Backup Tariff
Barrier-Related Costs	No
Back-up Power Costs	$50/kW-year

Background

A federal automobile testing facility in Michigan had large electricity loads created by 30 air-handling units and 3 large chiller units. Its peak demand was 1.6 MW during the summer and its power factor was very low. The lab was in a utility service territory with tariffs that included a $19.20/kW-month demand charge with a 12-month ratchet. In addition, a power factor penalty was applied as follows:
A penalty of 1 percent of the total bill, for a power factor of 80-84.9%
A penalty of 2 percent of the total bill, for a power factor of 75-79.9%
A penalty of 3 percent of the total bill, for a power factor of 70-74.9%
A penalty of 25 percent of the total bill, for a power factor under 74.9 percent for two consecutive months.

The lab had reached the 25-percent penalty on several occasions.

The lab began significant efforts to reduce its energy bill. The goal was to reduce its peak load from 1.6 MW to 800 kW. The primary change made was conversion of the three electric chillers to natural gas. The air handler motors were also being replaced with variable frequency drives. Under this same project, the lab desired to install a 200-kW fuel cell. The fuel cell was a showcase project and cost $800,000 to install after a $200,000 rebate being funded by the DOE's Energy Savings Performance Contract Program. The fuel cell cost, otherwise prohibitive, could be combined with the cost savings from the other measures to demonstrate an innovative energy system with an overall 10-year payback. The installation was to be completed in March 2000.

The 200-kW fuel cell would be connected to the distribution system at 480 volts and would operate as a base load unit. On the property was a substation with a 480 Volt to 40 kV transformer. The fuel cell had a transfer switch that allowed the unit to automatically disconnect if there was a fault on either side (lab or utility) of the system. In addition, a reverse power disconnect was installed even though the lab load profile was always above 200 kW of load. The fuel cell had an independent power connection that synchronized the fuel cell to the grid. With regard to the reverse power disconnects, the system was set up so that it could be turned on manually following a power grid failure to supply power to the facility during the length of the failure. The manual turn-on requirement was part of the utility requirements in case the reverse power disconnect failed to work.

Regulatory Barriers

Backup Tariff

The primary barrier to the project was a proposed back-up charge of $50/kW per year or $10,000 per year. At the time, the lab owned and operated a 375-kW diesel emergency back-up unit for which it did not pay back-up charges. The lab requested the utility to consider the new fuel cell project as a replacement for the older and less-efficient diesel with higher emissions. The lab had not been assessed back-up charges for the older diesel and expected the same treatment for the new fuel cell project. The project developer attempted to negotiate with the utility but did not obtain any reduction to the tariff.

Estimated Costs

The utility offered a 5 percent rate reduction for 10 years as an incentive to the customer to abandon this project. The tariff charges would add approximately $10,000 annually to the cost of the project. The contract for the fuel cell has not yet been written and approved, and negotiations continue.

Distributed Generator's Proposed Solutions

Although the back-up charge alone could not stop the project, the project developer argued that the penalty is incongruous with the need for peak reduction in the utility territory. During the summer of 1999, the utility contacted the lab to request that it reduce load to assist in meeting the summer system peak. It paid the lab $0.50/kWh to operate its back-up generator for two days.

Utility Position

The utility was contacted and answered several questions regarding its position on distributed power and related issues. The following information was related by the utility representative.

The utility is concerned with reverse power flow and standby services. The utility believes its procedures and processes for customers wishing to install distributed power is well organized. The utility has a detailed interconnection procedure that addresses most situations including protective equipment schematics.

The utility provides metering for customers who wish to sell power back into the grid. All "sellback" contracts are individually negotiated, although the utility admitted that this is sometimes a lengthy process. Customers are required to execute two tariff riders showing commitment to the process.

Customers must pay standby charges equal to the amount of the generation being installed. The utility does not allow non-Qualified Facilities to sell to the grid at any time, but it does allow interconnection of non-QFs. During peak summer months the utility requests customers with emergency generation to operate to shave load; however, the customer is not allowed to generate more power than they use.

Customers are required to pay for maintenance and calibration "periodically" (period not specified). Customers are required to pay for all equipment upgrades necessary to the utility's system as well as Supervisory Control and Data Acquisition (SCADA) remote control and monitoring equipment.

Case # 12 — 140-kW Reciprocating Natural Gas Engine-Generator in Colorado

Technology/size	Natural Gas Reciprocating Engines— 2-70 kW (derated for altitude)
Interconnected	Yes
Major Barrier	Technical Issues Associated with Additional Equipment
Barrier-Related Costs	$5,000 for Extra Equipment
Back-up Power Costs	None

Background

A customer installed a demonstration and testing facility at its headquarters building. This prototype installation provided the customer an opportunity to test natural gas engines for installation at remote locations along the company's natural gas transmission lines around the country. The installation consisted of two V8 reciprocating engines outfitted with 100-kW custom generation capability. The system output was reduced to a rated 70 kW each at altitude (5,600 feet).

The engines were installed in July 1998 after a one-month delay caused by mechanical installation issues. The generators were installed near the building service entrance and were connected to the building supply. The facility was tied to and dependent upon the grid for primary power supply. The engines did not produce enough energy to feed back to the grid.

The customer benefited directly from being able to test this equipment and software package on site. Further, the electricity generated reduced base load energy and peak demand from the grid during demonstrations and testing runs.

Technical Barriers

Interconnection Protective Equipment

The customer believed that the local utility presented opposition to the project through its business practices, although particular individuals within the utility expressed interest in its success. The utility demanded extensive redundancy in safety systems to protect the grid from these test engines. The customer found the expressed concerns for engineering quality and safety to be excessive considering the small size of the installation, including unreasonable demands for technical interconnection hardware and re-testing of proven equipment. For example, the utility initially requested that the customer place a relay in the generators' neutral circuit to protect against over-voltage. The length of the neutral conductor between the engines and the building (300 feet) was long enough to satisfy the utility's request for neutral impedance protection.

Power Factor[68]

This utility's practice with respect to power factor requirements varied widely from site to site. In some instances power factor standards were applied but not enforced. In other instances the utility metered the reactive power and charged the customer for it as part of the tariff or rate agreement. This could be an advantage to a distributed power operator who can set up the equipment to export VARs[69], although in most cases the utility does not compensate the project for reactive power benefits.

In this case, power factor requirements were a topic of long debate. The utility initially required the customer to bring the total facility power factor up to 0.9 from an average of 0.86 — this would have required the customer to install capacitor banks, or capacitors on many of its inductive loads in the building to correct the power factor. Although the power factor standard was contained in an existing tariff that applies to all customers, the utility was not requiring compliance from any other customers subject to the tariff, even though most large commercial facilities violated the 0.9 power factor standard. The utility nonetheless proposed to charge the customer for VAR demand and VAR-hours at a high rate specifically developed for this project and not on file with the Public Utility Commission. The developer attributed the attempt to force a high VAR arrangement on this project, and not on other customers, to a utility goal to establish a tough precedent for distributed power in preparation for future interconnection requests.

Distributed Generator's Proposed Solutions

The project managers believed that no interconnection agreement should be required for peak shaving systems, given that it is indistinguishable from any other load reduction measure. The project manager argued that a distributed power system configured to prevent power export to the distribution system should not undergo the additional scrutiny and cost of redundant switchgear and other protective equipment that may be appropriate for systems exporting power.

Further, it was argued that the technical interconnection requirements for distributed power can be tailored in advance to certain applications, e.g., peak shaving, base load, etc. Ideally, common interconnect standards and requirements should be in place for each application to allow mass produced, lower-cost system components. Development of standard system components to satisfy utility concerns in particular applications would not only markedly lower the cost of the installation, but would result in products that maximize system and operational efficiencies over the life of the system components. In the opinion of the project manager, the requirement should be for the generators to supply their fair share of the VARs, and no more.

Cost Estimate

The installation ultimately resulted in an additional charge of $3,000 for equipment that was considered redundant and a $2,000 equipment testing charge that was considered unnecessary.

Utility Position

The utility was contacted and answered several questions regarding its position on distributed power and related issues. The following information is as related by the utility representative.

The utility noted that if a distributed power project is large enough, it may have to bid into the utility's resource solicitations under a competitive bidding process. The utility promotes distributed power and is assisting the development of the proposed IEEE national guidelines.

The utility's concerns with distributed power installations involve protection for the grid, including: safety, harmonics, over and under voltage protection, etc. It requires specified utility-grade relays for large generators and type testing of components for small generators.

The utility allows resale back to the grid, even by non-qualified facilities. In small solar cases, a pilot net metering tariff applies. All customers generating in parallel to the grid are required to sign contracts. In

[68] Power factor is the ratio of real power (kW) to the apparent power (kVA).
[69] Volt-amperes reactive (VAR) is the apparent reactive power delivered to the grid.

addition, all facilities must install appropriate technical equipment for selling power back to the grid, even if it does not intend to generate enough power to sell back into the grid.

The demand charge structure does not change if a customer elects to self-generate to reduce their demand and energy use. The utility energy charge for power supplied by the utility varies and it may change with a "buy all-sell all" contract in place. The utility stated that most customers sell power directly to the utility itself, but transport on its distribution system would be allowed at the customer's request with the associated uplift and transmission charges.

Case #13 — 132-kW Solar Array in Hopland, California

Technology/size	Solar/ 132 kW
Interconnected	Yes
Major Barrier	Regulatory—Wholesale Distribution Tariff
Barrier-Related Costs	$25,000 (Eventually Dropped)
Back-up Power Costs	None

Background

The Real Goods Solar Living Center (the Center) was built as a demonstration site for sustainable living. Recently the center issued the following press release announcing the installation of this project. Because of this press release, we make the exception in revealing the location and developers associated with this project.

Real Goods Trading Corporation and the Institute for Solar Living announced the official launch of the brand new 132 kW solar power array.

The Solar 2000 Mendocino array is the nation's first independent commercial solar power plant directly resulting from customer choice. The array will be owned and operated by GPU Solar, Inc. (actually AstroPower which is a subsidiary of GPU Solar) and the electricity sold under a long term contract to Greenmountain.com.

Real Goods Chairman and founder, John Schaeffer, said, "Not only is this project a great boom for the environment in its own right, it is also a very important demonstration effort. We expect other commercial developments to follow our example. This beautiful array, which is clearly visible from Highway 101, will become another magnet for travelers. Already 150,000 people a year visit our Solar Living Center, we expect many more next year. Further, it solidifies the community of Hopland's undisputed status as the Solar Capital of the World."

This project is providing power to the grid. Most of the power generated by the project will actually be used by the Center; however, it will be connected to the utility 12-kilovolt (kV) distribution system, thus allowing the sale of the power to Green Mountain.

The site installed a 132-kW DC peak (105 kW AC rating at standard test conditions) solar-crystalline, ground-mounted PV system.

Regulatory Barriers

Wholesale Distribution Tariff Agreement

The most significant barriers were regulatory. Since this project was a test case for the utility, the California ISO, and the Automated Power Exchange (APX), procedures were developed for the first time. Thus, negotiating the Wholesale Distribution Tariff Agreement with the utility became a complex process. This tariff, sometimes referred to as an uplift tariff, was necessary to complete a contract path into the California ISO for scheduling. Once the power is scheduled into the California ISO, power can find its way to the retail market it was designed to serve. The wholesale distribution tariff was "temporary" and subject to FERC review. As of October 1999, there were no charges associated with the actual distribution of power on the utility's system.

Technical Barriers

This installation was breaking new ground in California. The developer believed that as a result, the utility was not prepared to address such a small installation as a generation provider. The utility did have a conventional interconnection agreement; however, it was designed for projects over 10 MW. To interconnect with the grid, the utility required an interconnection study that is still ongoing. In addition, the project developer paid for the service drop, meter, and the step-up transformer (480 Volt/ 12 kV).

A major technical interconnection issue was the requirement for additional protective relays. The inverter equipment already supplied protective relays including ground fault protection relays, under/over voltage protection, and under/over frequency protection. Thus, if there were any kind of fault on either the utility side or the solar site side, the inverter could ensure that the site would automatically shut down.

The utility initially requested installation of additional protective relay equipment that cost between $25,000 and $35,000. This additional protective relay equipment was redundant to the protective relays already provided with the inverter. After negotiations, the utility ultimately agreed that this additional equipment was not needed.

Distributed Generator's Proposed Solutions

The project developer was working closely with the utility to resolve the technical and procedural interconnect issues. The developer was still hoping to negotiate a reasonable solution to the request for redundant relays.

In the project developer's opinion, identifying the right person at the utility was critical and maintaining contact with the individual was also important. If the project developer and the utility had not worked together, the project would have been more difficult and could have been delayed.

Case #14 — 120-kW Propane Gas Reciprocating Engine for Base Load Service at Hospital

Technology/size	Propane Gas Recip Cogen for Absorption Chiller and Hot Water Heating/ 120 kW
Interconnected	No
Major Barrier	Technical—Safety Equipment Business Practices—Discount Tariffs
Barrier-Related Costs	$7,000
Back-up Power Costs	None

Background

A developer was installing a 120-kW propane gas reciprocating engine in a remote area where natural gas was not available and the cost of demand and energy quite high. The project was being installed on the low voltage side of a hospital's own 12.4-kV to 120/2080-volt step-down transformer. This facility was being charged an energy charge of 8.69 cents/kWh and a demand charge of $5.75/kW-month. In addition, because the hospital had a high hot-water bill, it was a good candidate for a cogeneration project. The hospital's monthly electric bill was typically around $12,500/month and the gas bill was $4,700/month. Part of the electric load included chillers that needed to be replaced.
The project was intended to operate as a base load unit. In addition to supplying 120 kW of electric power, the project will also supply hot water to a new absorption chiller and for hot water heating. The project allows for the elimination of a 5-ton heat pump that has been used for heating the swimming pool. With the new installation, the swimming pool can be heated at night when the absorption chiller is not needed. The proposed project will maintain this temperature with only 3 hours of recovered heat a day transferred to the pool.

Technical Barriers

Many of the barriers associated with the project have been technical issues that required resolution between the utility and the developer. The project was scheduled for completion on May 1, 1999. As of September 27, 1999, even though the inspection was complete, the developer had not received a letter from the utility allowing the unit to run for purposes other than testing. These technical barriers include the following:

- The utility requested a lightening arrestor that costs $20,000. The developer is still negotiating with the utility and the issue has not yet been resolved. The lightening arrestor is for the underground 12.4-KV primary voltage line. No other location in the state has this equipment installed at this time.

- The utility requested that a breaker rated for 2000 amps be installed on the low voltage side of the transformer. The building already had 2 separate 1600-amp breakers (for two separate feeders). The equipment specified has not been made since 1982, and GE quoted a cost of $40,000 and six months lead time. This was pointed out to the utility, and the requirement was dropped.

- The utility stated that the high voltage feed was not grounded, and an inspection was required to prove that a high-voltage ground existed. Scheduling the inspection took one month.

The utility requested a reverse power relay, even though this installation is an induction generator that requires an outside source of voltage to operate. The original relay specified by the utility was not appropriate for the installation, and General Electric (supplier of the relay) would not warranty it in the application. The utility agreed to a different relay as specified by General Electric; however, this process took an additional eight weeks. The utility required synchronizing equipment and parallel operation monitoring for the induction generator that has a reverse power relay installed that shuts down the entire cogeneration plant. This cost was over $6,000 for equipment that the developer argued was unneeded.

Regulatory Barriers

Back-up Charges

When the project was proposed, the utility had no standby charges in their tariff. During the project development, the utility requested a $1,200/kW-year standby charge from the PUC. However, the request to the PUC was rejected on the basis that 120 kW could not affect the grid.

Business Practice Barriers

Discount Tariff and Anti-Cogeneration Campaign

The utility has openly discouraged its customers from installing cogeneration facilities and switching to cheaper more-efficient power. In a publication sent to all customers, the utility stated that cogeneration is inefficient and expensive. The publication points out "the heat produced by the cogeneration system cannot be fully utilized by the facility that it serves. Any wasted thermal energy is a lost opportunity for cogeneration units." The publication did not point out that without cogeneration (with the traditional generating station) all the thermal energy is lost.

The utility's publication specifically targeted the addition of absorption chillers to a cogeneration installation. A developer had recently been promoting this technology and had 20 installations in the utility's territory. The publication stated, "The absorption chiller is being added in an attempt to use more of the thermal energy available from the fuel to improve cogeneration system performance. In the past, absorption chillers have not been used because of their very high energy consumption and poor efficiency. For example, a typical absorption chiller requires 1 Btu of energy to create 1-1.2 Btu of cooling. In contrast, a high efficiency electric chiller, such as those qualifying for utility rebates, provides 7 Btu's of cooling energy for every Btu of energy supplied to the chiller." The publication again did not mention that the absorption chiller uses 1 Btu of energy from waste heat that would not be used except in the chiller application. On the other hand, the Btu's used for the electric chiller must be generated by the utility and paid for by the customer.

The utility also stated that the economics of cogeneration were difficult because of the lack of availability of natural gas. Yet, the utility was offering discounts to customers that did not install their own generation source. The utility had introduced a tariff reduction of 11.77 percent for customers who seriously considered cogeneration but opted to stay with the utility. The tariff required the customer to conduct economic analyses showing the savings associated with cogeneration. In addition, the customer must provide cost estimates from vendors showing the cost savings.

At the same time, the utility did have programs to support renewable energy. They had a rebate program for residential solar hot water heaters and an educational program to install photovoltaic systems (PV) in schools. These installations were installed on the customer's side of the meter; thus, the energy generated by the PV project would only be available to the school.

Estimated Costs

The costs associated with this project were primarily associated with the additional equipment required. The additional costs included $7,000 for what the developer believed to be unnecessary equipment and possibly another $20,000, still in negotiation with the utility.

Distributed Generator's Proposed Solutions

In this case, the PUC prohibited the utility from imposing a back-up tariff that would have stopped the project. This case shows that barriers can be removed with regulation. On the other hand, the PUC has also continued to allow incentive tariffs for customers that stayed with the utility instead of installing more efficient cogeneration. (See discussion of economic or uneconomic bypass at notes 44 and 58 on pages 23 and 28.)

The cogeneration plant developer believed that it had met or exceeded all interconnection requirements by the utility, but the utility had not yet allowed the unit to go on line at full output. The plant could operate 95-percent output for testing and documentation. The utility did not provide a schedule when the unit would be allowed to operate.

Case # 15 — 75-kW Natural Gas Microturbine in California

Technology/size	Natural Gas Microturbine/ 75 kW
Interconnected	No
Major Barrier	Regulatory—Utility Prohibition to Interconnection
Barrier-Related Costs	$50,000
Back-up Power Costs	Not Known

Background

In this case, an oil and gas producer with a well located at a public school in California sought to install a 75-kW microturbine and had been unable to interconnect the facility with the local utility under acceptable terms. The principal obstacle was a fundamental disagreement regarding the utility's legal obligation to interconnect a non-utility-owned generating facility, which did not meet the legal definition of a QF under the federal PURPA statute.

The project owner had a producing oil well located on the school property. The well also produced natural gas, which the school had been processing and delivering for sale into a natural gas pipeline. The producer hired a consultant to explore the possibility of capturing additional value from the natural gas by using it to fuel an on-site electric generating facility to power the oil derrick and to use residual heat from the generating facility for space and water heating at the school.

The energy project developer contracted with the school to install a 75-kW microturbine on the school property, in part to allow both the project developer and the manufacturer to gain operational experience with this relatively new product. The project developer planned to operate the facility, with the entire output of the microturbine going directly to meet the oil derrick's electrical loads. Because the derrick's electricity demand of approximately 1,000 kW is larger than the microturbine's 75-kW generating capacity, none of the electricity generated would be delivered to the utility. Assuming that the microturbine was operating at a 95-percent capacity factor, it would produce approximately 52,000 kWh per month, with a value (assuming retail prices of $0.10 per kWh) of approximately $5,200 per month.

The project was installed in July 1999 and operated briefly to ensure operational readiness. The project was then shut down because the project developer had been unable to negotiate an acceptable interconnection agreement with the local utility. As of September 1999, the project remained stalled because no agreement had been reached.

Regulatory Barriers

Utility Prohibition to Interconnection

The project developer stated that recent changes in California law opened the way for the interconnection of non-QF as well as QF generation and that the utility publicly had stated there was "no problem" with interconnecting to the utility. However, the utility refused to interconnect, arguing that it had no legal obligation to do so. The utility interpreted its obligations to interconnect non-utility-owned generating facilities as being limited under the federal PURPA statute to QFs, which included facilities powered by renewable resources such as sun, wind, and water and cogeneration facilities. Because this microturbine did not meet these criteria, the utility's position was that it had no obligation to interconnect the facility to operate in parallel with the utility.

The project developer's response to the threshold question of an obligation to interconnect was that PURPA QF requirements apply only to facilities that are exporting power to the utility and not to facilities that are merely offsetting on-site loads and will never produce excess power, for sale or otherwise. In effect, the project developer argued that the facility was a "load reduction device" that was functionally indistinguishable from any other variable loads on the customer's property, over which the utility has no control. Having met legitimate safety and power quality requirements, the customer argued it was legally entitled to interconnect a generating facility to manage its load and partially supply its own electricity needs.

Following the initial legal dispute on the right to connect, the utility offered to interconnect the project under a new version of its Rule regarding parallel generation by non-utility, non-QF facilities. The Rule required projects to purchase standby power under a Schedule S. When subsequent review of Schedule S showed that it also required the project to be a QF, the utility acknowledged the inconsistency and offered to approach interconnection through a simplified regulatory proceeding called an "advice letter filing."

When the project developer requested the advice letter, the utility responded that the project was determined to have substantial "revenue impacts." Management decided not to submit an advice letter filing until the revenue impacts could be resolved to its satisfaction.

Pressed by the project developer, the utility offered to interconnect under an "experimental" or "test" interconnection agreement, which allowed the parallel operation, but without compensation for electricity delivered to the utility. All of the electricity generated would be delivered to the utility without payment or other compensation, while the facility purchased all of its electricity from the utility at standard retail rates. This proposal would result in the project developer incurring all the capital and operating costs of operating the facility and none of the economic benefit.

Operational Requirements: Independent System Operator (ISO) Requirements

The project developer noted that under existing rules in California, distribution-level generators have no way to wheel power to the ISO responsible for coordination and dispatch of power under retail competition in California. This is reflected in the contracts that the utility proposed, which specified that the utility would not wheel power on behalf of the project. The project developer suggested that the California ISO may itself be looking at solutions to this issue, but that at this time there are none.

Business Practice Barriers

Interconnection Studies

During negotiations on interconnection, the utility also indicated that it would require the project developer to pay for a method of service study required for all non-utility generating facilities except those specifically exempt[70]. The utility did not provide a fixed price quote for conducting the study, which is to evaluate the impacts and modifications posed by the proposed interconnection. The minimum charge for the study is $500. This utility has charged as much as $50,000 for such studies in other cases, taking up to six months to complete. The project developer anticipated $50,000 as the cost of the study for a project of this size, but because the utility did not provide any further estimate, there was no way to plan for or challenge the cost. The utility informed the project developer that the cost of the study is non-negotiable, and that the project developer's only option, if unwilling to pay for the study, would be to abandon the project.

The project developer argued that a study intended to determine whether the distribution system could accommodate power being delivered by the generating facility was unnecessary and inappropriate for a generating facility designed merely to reduce or offset the customer's own loads. The system would never export any power to the utility system. The utility, nonetheless, declined to negotiate.

[70] Small solar and wind facilities qualify for interconnection under the California net metering law, which prohibits the pass-through of such costs.

Contractual Requirements for Interconnection

The utility's proposed contract to the project developer was a 43-page commercial contract that the project developer characterized as "onerous" and overly complex for a generating facility of the size and scope involved.

Processing Requests for Interconnection

The project developer complained about the utility's failure to designate a particular employee or a single office to act as the point of contact for the project. The project developer stated, "Wiggling your way through these rules and tariffs is a non-trivial exercise because the tariff office, the business office, and the billing office all have different interpretations regarding the requirements."

Technical Barriers

Safety and Power Quality Requirements

The turbine manufacturer provided the utility with written documentation of the results from tests of the protective functions of its microturbine, including safety and power quality features. The utility declined to accept the tests and indicated that it would perform its own tests of the equipment at the project developer's expense.

In addition, the utility indicated that it would not accept its own testing of a single microturbine as a "type test" for prequalification and acceptance of other microturbines of the same make and model from the manufacturer. Instead, the utility indicated that it would require individual testing of each unit.

The project developer characterized the utility as more accepting of the protective equipment used for synchronous and inductive generators, because these requirements were well defined under rules for PURPA QFs. The project developer noted that the utilities were less comfortable with generators (such as the microturbine in this case) that connect through an inverter. According to the project developer, inverters have the protective functionality to disconnect in response to abnormal utility conditions. For instance, a short circuit in the distribution system can be exacerbated by a synchronous generator, but not by an inverter-coupled generator that automatically shuts down under short-circuit conditions. The project developer noted that this "inherent functionality" was not yet generally accepted by utilities, except where national standards have been developed—such as in small PV installations. The developer argued that incorporation of the built-in protective functions was part of the competitive economics of the facility, and the project could not economically justify the cost of additional, redundant protective equipment.

Distributed Generator's Proposed Solutions

The project developer and microturbine manufacturer suggested several solutions to overcoming the barriers encountered in this project.

The project developer favored the development of national standards to address legitimate safety and power-quality issues. Once "everyone agrees that IEEE/UL has the ability to define, test, and approve equipment" the utility could not require additional testing of certified models, much less testing of individual units.

The project developer favored quick connection for generating facilities that do not export power to the utility system. Facilities studies, such as the Method of Service Study in this case, are not necessary and should be prohibited as a delaying tactic for systems that merely reduce the customer's demand. These systems can have no adverse effect on distribution system capacity.

Moreover, for cases where power is exported and a facilities study may be appropriate, there should be some way to categorize and standardize the approach based on generation size, voltage level, etc., so as to avoid the expense, time, and inconsistency of custom engineering studies. As the project developer noted, "every distribution engineer has a different perspective and they consider it more of an art than a science." The case-by-case approach does not allow for standardized systems and prevents the emergence of commercial markets for customer-owned equipment.

The microturbine manufacturer argued for the need to "take the interconnection decision out of the hands of the monopoly utility, who sees this customer as a competitor." The manufacturer favored legislation to create a fair market, perhaps by requiring the appointment of an independent arbiter to decide what facilities can be interconnected and under what terms and conditions. The manufacturer described the process as "fighting a huge machine — with thousands of engineers, thousands of lawyers — with the burden on the applicant's [project developer's] side." According to the manufacturer, "the utility shouldn't be involved at the level of having discretion over the terms and conditions of the project."

The manufacturer argued that the PUC is not an adequate or efficient arbiter for these projects, because regulatory and judicial burdens are unworkable as a long-term solution; the costs are prohibitive and unsustainable for project developers. Even if the PUC were adequately responsive, the costs of filing complaints and the delays associated with hearing disputes are unacceptably long for project developers. The result will be the abandonment of otherwise viable projects.

Case #16 — 50-Watt to 500-kW Wind and PV Systems in Texas

Technology/size	Wind and Photovoltaic 50-50 Watt to 500 kW
Interconnected	Yes
Major Barrier	None
Barrier-Related Costs	None
Back-up Power Costs	None

Background

In this case, a state university in Texas sought to install 50 PV and wind systems in sizes varying from 50 Watts up to 500 kW (from multiple manufacturers) from 1974 through 1999. The university experienced no problems working with their local utility.

The projects were primarily for research and development (R&D) purposes. Some were intended for irrigation and stripper wells. Most were grid-connected.

Both the project developer and the utility attributed the ease of interconnection to several factors, including:

The utility's interest in the data gathered from the R&D process. The utility was particularly interested in understanding the technology and the locally available solar and wind resources.

The R&D nature of the project failed to raise commercial concerns.

The fact that the university was involved brought a great deal of technical knowledge, financial resources, and staffing to the projects.

The fact that the State government was involved limited the utility's concerns regarding liability issues.

The utility was interested in being a good neighbor to the state government institution.

The utility's only expressed concern was with the safely of utility workers. The University's technical expertise and the State's liability self-insurance allayed these concerns. The utility did require a separate disconnect switch on each of the generating facilities.

The utility also stated that separate metering and computation (as the alternative to net metering the facilities) was "not worth the paperwork," so each of the facilities was net metered (even though Texas requires that utilities offer net metering only for facilities 50 kW or smaller). The utility donated the engineering time required to review and assist with the interconnections because the utility "wanted to contribute to the community."

The extraordinary ease of interconnection and operation of this wide range of facilities in the university R&D setting suggests that the interconnection barriers can be expeditiously addressed where there is a common will to do so.

Case #17 — 43-kW and 300-kW Commercial Photovoltaic Systems in Pennsylvania

Technology/size	Commercial Photovoltaic/ 43 kW
Interconnected	No
Major Barrier	Business Practices—Lack of Procedures and Appropriate Interconnect Agreements
Barrier-Related Costs	$35,000 to Interconnect
Back-up Power Costs	Not Known

Background

A developer of solar projects installed a 43-kW solar photovoltaic project that was brought on line on April 22, 1999. It was connected to the customer's side of the utility grid. The solar panels were a flat-roof design and were grid connected without battery storage. The purpose of the project was to sell power into the grid to be marketed as green energy.

The project only supplied one to two percent of the customer's energy; however, the customer's goal was to install similar projects at all facilities, making a significant addition to the amount of installed solar capacity on the grid. In addition, the customer expected a capacity benefit because it was a commercial account and hopes to reduce the peak demand charges.

Another solar project, not yet installed, will provide 300 kW of green power to customers in the region. This project will be unique in that it will be installed at a landfill site where methane gas will be used to power a gas turbine that currently provides power to the utility distribution system. The solar panels will be installed on land that is no longer in use by the landfill site; an added benefit of the project is the productive use of the landfill site.

This solar project will be connected to the grid using the electrical interconnection capability of the landfill's existing gas-to-electricity project. Essentially, the solar project will piggyback on the existing landfill project to avoid new interconnection issues. The landfill project is operated under a PURPA contract with excess interconnection capability at this generation site. Using the existing connection, the new project will avoid several utility interconnection issues. Instead, this project has been delayed due to a lack of financing.

Business Practice Barriers

Procedural Requirements for Interconnection

The project developer initially intended to install the solar rooftop project so that power could be delivered to the utility grid. This would allow the marketing of green energy and the ability to provide more green energy through repeated installations. However, with the rooftop solar project, the costs to connect to the grid side of the utility meter would have been prohibitively expensive. The utility did not appear to be familiar with the idea of small generators selling back into the grid, and required engineering evaluation and consulting response. The developer calculated preliminary estimates on the cost to connect to the utility side of the grid at $30,000 to $40,000 (or $700 to 930/kw).

The developer decided that the size of the project did not warrant the paperwork, time and expense to proceed with the risks of a test case for the utility. Primarily, the cost would have been the employees' time, but the developer was also concerned that the process could have easily been stopped by expensive equipment requirements. This opinion was based on the developer's own experience and that of others in the industry with experience dealing with utilities in the region. The business decision was that the potential cost of interconnection procedures would be prohibitive. If the project were larger, the anticipated cost of the process may have been warranted.

Even without connecting to the utility grid, an interconnect agreement was required to install the unit on the customer side of the meter. The original interconnect agreement provided by the utility was written for generators larger than 1 MW. It was quite extensive and the developer refused to sign. After discussions with the utility for two months, the developer signed a streamlined and simplified interconnect agreement. The developer felt that most of the difficulty appeared to result from the utility's lack of experience in dealing with small generators.

Estimated Costs

The customer paid an interconnection application fee of $250, or $5.81/kW on the 43-kW project. The developer calculated preliminary estimates on the cost to connect the rooftop facility to the utility side of the grid at $30,000 to $40,000 ($698/kW to $930/kW) in custom engineering and consulting fees.

Distributed Generator's Proposed Solutions

To expedite interconnection, utilities must establish a simple procedure that allows for small generation projects to be connected to the grid—analogous to what has been done in the net-metering rules.[71] The interconnect agreement provided by Eastern Utilities in Rhode Island to meet the needs of smaller generators could be used as a template for other utilities.

Utility Position

The utility's basic concern with distributed power was that when its system trips, it wants to ensure that the distributed power installation also trips in order to ensure that islanding does not occur. If islanding does occur, the utility does not have control over the frequency and voltage that the distributed power installation would provide to the grid. Thus, the most important equipment is under/over frequency and under/over current protection. In addition, a grounded-Y source is also important. The utility does allow sale back into the grid if the unit is a Qualifying Facility under PURPA.

Case #18 — 35-kW Wind Turbine in Minnesota

Technology/size	Wind Turbine/35 kW
Interconnected	Yes
Major Barrier	Business Practices—Excessive Fees
Barrier-Related Costs	$50/month
Back-up Power Costs	Not Known

[71] A utility in Rhode Island has a one-page interconnect agreement that developers are providing to utilities as a template for small generator interconnect agreements. The Texas PUC has developed a simple five-page interconnection agreement for distributed generating facilities.

Background

In this case, a farmer in Minnesota interconnected a 35-kW wind turbine to his local utility (a rural electric cooperative) and has been obligated to pay a substantial monthly fee to the utility. The principal obstacle is the expense associated with the utility's "transformer fee" of $50 per month.

The project was installed and began operation in 1992. The purpose of the installation was to reduce the farmer's electricity bills by offsetting the farmer's energy purchases and selling any excess energy to the utility during several months of the year when the turbine produces more energy than the farm consumes.

The project owner believed that the utility had been extremely uncooperative. The customer further concluded that the utility's purpose was to avoid state-mandated interconnection if it could find a way to do so. He reported that the utility was slow to respond to requests and otherwise discouraging, with the apparent purpose of discouraging the project.

Business Practice Barriers

Transformer Fees

The utility charged farm customers a monthly "transformer fee" of $50, which was in effect, a minimum monthly bill. According to the farmer, other farm customers who do not self-generate electricity inevitably had more than $50 per month in electricity usage charges, so the $50 minimum "transformer fee" did not affect them. The farmer, however, indicated that he produced a net surplus of power during three or four months of the year and during those months the utility charged him the $50 fee. Thus, the farmer has no incentive to generate enough electricity to offset the last $50 worth of electricity he used, because he derives no economic benefit from doing so.

Interconnection Fees

The utility also required the customer to pay approximately $250 for an additional meter to separately track the energy delivered by his wind turbine to the utility. The utility requested the customer to install a load meter at the generator to be

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sure that the customer did not exceed the 40 kW cap on net metered facilities in his state. The customer refused to pay the cost of the additional meter, and the utility allowed the interconnection without the meter.

Distributed Generator's Proposed Solutions

The customer believed that effective operation of interconnection laws will require a specified contact at the PUC who knows the rules regarding interconnection and can drive utilities to abide by them. The laws must be very simple in order to prevent parties from manipulating the provisions. The customer believes that he had no one to turn to when the utility attempted to make interconnection difficult.

3.3 Individual Case Study Narratives for Small Distributed Power Projects (25 kW or Smaller)

The case studies included in this size category cover solar photovoltaic (PV) systems, wind turbine generating facilities, and one PV/propane system. They vary in size from 300 Watts (0.3 kW) to 25 kW. The distributed power facilities in this size range are residential, commercial, agricultural, and institutional customers. The only technologies readily available commercially are PV and wind systems[72], although some micro-cogeneration units are in limited use, and fuel cells in this size range are expected to be commercially available within a few years.

Because of the relatively small amounts of electricity being produced, small distributed power facilities are particularly vulnerable to interconnection requirements that increase the costs of interconnecting and operating their facilities, even if these costs seem modest. The following is a description of the issues most frequently identified by small distributed power projects as barriers to interconnection.

This section of the report provides the more significant case studies. These eight cases were chosen from the 19 cases as a representative cross section of the barriers encountered. The cases are organized by size as follows:

- 25-kW PV System in Mid-Atlantic Region.
- 18-kW Wind Turbine and 2 kW PV System in the Midwest
- 17.5-kW Wind Turbine in Illinois
- 10-kW PV System in California
- 3-kW PV System in New England
- 3-kW PV System in California
- 0.9-kW PV System in New England
- 300-Watt PV System in New England.

Case #19 — 25-kW PV System in Maryland

Technology/size	Photovoltaic (25 kW)
Interconnected	Yes
Major Barrier	Business Practices—Request Processing
Barrier-Related Costs	$5,000
Back-up Power Costs	Not Applicable

Background

In this case, a community college in Maryland decided to install a large PV system on the roof of a college building. The system included 25 kW of thin-film PV modules and eight series inverters. These inverters were UL listed and complied with the IEEE P929 standard. The college sought to interconnect the system to the local investor-owned utility. The pivotal barrier encountered was the utility's delays in processing of the customer's request for interconnection. The customer also had to deal with multiple utility representatives.

Business Practice Barriers

Processing Requests

According to the system integrator, the utility's response to the request for interconnection was "five different people asking the same questions at different points in time." The utility originally required a test of the inverter safety functions, at which utility engineers would be present. The test procedure was set up at a substantial expense to the system integrator. Then the utility reported that because the system would never produce excess

[72] Micro hydro or small biomass facilities are available, but utilized largely only in international markets.

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power for delivery to the utility grid, no test was necessary.

Moreover, the system integrator reported that the utility's "local representatives, front office people, and distribution engineers all ask the same questions regarding the same system, and all give conflicting answers to the installer's questions." When the system integrator moves on to another site in the same or a different utility's service territory, he states that it is "déjà vu all over again."

Estimated Costs

The system integrator spent approximately 100 hours working with various utility representatives negotiating and responding to interconnection requirements. The system integrator charged S50 per hour for his time, so the economic loss was approximately S5,000. The system integrator was unable to offer a reliable estimate of the time spent by the community college or the utility on the project, although he indicated that the time spent by these other parties also was substantial.

Distributed Generator's Proposed Solutions

The system integrator suggested that the customers should be able to say to the utility, "there's a law that says what the interconnection standard is. I am in compliance with that law and those standards. I therefore have a right to interconnect. I am not going to answer a dozen phone calls from five different people or conduct redundant and unnecessary tests for your benefit."

Case #20 — 18-kW Wind Turbine and 2-kW PV System in Ohio

Technology/size	Hybrid Wind (18 kW) and Photovoltaic (2 kW)
Interconnected	Yes
Major Barrier	Business Practices—Request Processing
Barrier-Related Costs	$6,500
Back-up Power Costs	Not Known

Background

In this case, a residential customer in Ohio sought to install an 18-kW wind turbine and a 2-kW PV system and encountered "resistance" from the local utility. Overcoming the utility's resistance and obtaining interconnection required approximately 200 hours of the customer's time and approximately $6,500 in attorney and expert fees. It also caused a delay of nearly 12 months.

Business Practice Barriers

Processing Requests

In August 1994, the customer met with the utility and was told that the utility had never heard of the idea of interconnecting such a system to the grid and that it did not think he should do so. An attorney, a consumer representative, an engineer, and a power plant engineer represented the utility at the meeting. The utility declined the customer's request to interconnect. The customer told the utility that Congress had said that he was allowed to interconnect [under PURPA]. The utility replied that it would not cooperate with him. The parties set a date for a future meeting.

Two months later, the customer went to the scheduled utility meeting with his attorney, an electrician, his installation contractors, and a zoning expert. They all supported the customer's plan. The customer also had support letters from the U.S. Environmental Protection Agency (EPA). The utility said it would draw up the paperwork to complete the interconnection.

Three months later (January 1995) the parties and their attorneys met again to discuss the contract. The customer was dissatisfied with the terms of the contract, particularly with respect to the terms for power purchase, but he agreed to the terms.

In March 1995, the customer broke ground on the house, and in May 1995 the contract was finalized.

The customer stated that during his negotiations with the utility, the utility changed personnel three times.

Fees and Charges

The utility offered to pay 1.2¢/kWh for the excess electricity generated by the customer. The parties negotiated on the price, and eventually settled at 1.9¢/kWh. The utility also imposed a monthly fee of S15 to read the customer's meter.

Technical Barriers

Safety and Power Quality Requirements

The utility wanted the customer to pay for a separate meter, transformer, and power pole. The customer responded that he was being penalized for installing the generating equipment and that if he were simply building the residence and business the utility would pay for this equipment. After continued negotiations, the utility agreed to provide these distribution facilities at no cost to the customer.

Distributed Generator's Proposed Solutions

The customer believed that the utility's attitude and the interconnection requirements it imposed encouraged people to interconnect systems to the utility grid without informing the utility.

The customer suggested that the utility should offer, "one-stop shopping" for distributed power. According to the customer, "They are in the business. They should make it easy and make money off of it. They should sell and install the equipment."

Case #21 — 17.5-kW Wind Turbine in Illinois

Technology/size	Wind (17.5 kW)
Interconnected	Yes
Major Barrier	Business Practices—Request Processing
Barrier-Related Costs	$300
Back-up Power Costs	Not Known

Background

In this case study, a residential customer in Illinois sought to install a 17.5-kW wind turbine and inverter. The customer encountered what he believed to be overly complicated interconnection requirements, extensive protective equipment requirements, expensive interconnection fees, and utility delays. The project was installed in 1993.

Business Practice Barriers

Interconnection Agreement

The utility's initial response to the customer's inquiry regarding interconnection was to send him information and a list of contacts of other customers who had experienced problems with wind technology. After 3 to 4 weeks, when it became clear that the customer still wanted to move forward, the utility sent the customer 37 pages of information including "Utility Requirements" that the customer and the customer's electrical engineer found incomprehensible. The package sent by the utility also included an electric service contract and a parallel operations contract.

Interconnection Fees; Other Charges

The utility required a $300 engineering service fee. The customer paid the $300 engineering fee, and sent a schematic for the inverter to the utility. The utility approved the application after a delay of three months.

The customer paid the utility 10.5¢/kWh for electricity, and was paid 1.1¢/kWh for the excess electricity the utility buys back. The customer complained about the failure of the utility to recognize the higher value of electricity generated from a renewable resource, and the higher value of electricity generated close to where it is needed (which avoids line losses).

The utility charges approximately $2.50/month for meter rental and a small additional fee for reading the meter.

Making Contact

The customer reported that it was very difficult to reach the utility engineer and the customer's phone calls often were not returned. As described by the customer, after the system was installed, the utility sent "three van loads of engineers and a car load of white-collars [managers] to inspect the installation." The customer stated that none of the utility personnel appeared to have the technical knowledge necessary to evaluate the system. The customer demonstrated the system to them. According to the customer, the utility engineers were curious, but the managers were "very difficult to deal with."

Processing Requests

The requirements put in place by the utility delayed installation of the project for approximately three months. The electricity generated by the wind turbine produced energy savings of approximately $120 per month. Therefore, the delays in installation caused an economic loss to the customer of approximately $360. The $300 engineering fee caused the customer to lose approximately 20 percent of the first year's energy savings. Since the installation was completed, the customer has had no problems with the utility.

Technical Barriers

Safety and Power Quality Requirements

The utility required expensive manual and automatic disconnect breakers, synchronizing relays, voltage transformers, an under/over voltage relay, and an under/over frequency relay.

The customer spoke with his wind turbine supplier, who had a representative contact the utility regarding the features and performance characteristics of the inverter. The utility then rescinded most of these requirements.

Distributed Generator's Proposed Solutions

The customer believed that the utility's negative attitude encouraged customers to interconnect without contacting their utility. He also believed that the utility mindset on these systems is resistance not cooperation. To facilitate the process in the future, the utility needs a staff person whose responsibility it is to understand and expedite requests for interconnection.

Case # 22 — 10-kW PV System in California

Technology/size	Photovoltaic (10 kW AC)
Interconnected	Yes
Major Barrier	None
Barrier-Related Costs	None
Back-up Power Costs	Not Applicable

Background

In this case, a residential customer in California purchased and installed a 10-kW PV system including 40 modules and 2 sine wave inverters. The inverters were UL listed and complied with the IEEE P929 standard. The local investor-owned utility cooperated with the customer, requiring only two things: (1) A "hold harmless" document from the customer's insurance company and (2) a visible, lockable disconnect switch. The customer provided both and proceeded with the installation of the system. The utility sent an engineer for the final utility inspection. The inspector had been involved with two previous PV inspections. He verified that the inverters were as specified, checked for the lockable disconnect, and approved the system for interconnection.

This case illustrates the extent to which the process can be streamlined and simplified with the full implementation of the California net metering law. As recently as six months before this customer sought to interconnect his system, other customers with similar generating facilities reported substantial difficulties in obtaining prompt, efficient interconnection with this same utility.

Moreover, it should be noted that eligibility for net metering in California is limited to residential and small commercial customers with solar and small wind generators under 10 kW. We found that distributed generators that are not eligible for net metering are still frequently encountering substantial problems in seeking prompt, efficient interconnection of their systems.

Nevertheless, cases like this one in which customers are reporting few, if any, problems in obtaining interconnection are becoming more common in this size subcategory of distributed generators. We are optimistic that substantial progress is possible in addressing and overcoming the problems identified by other distributed generators in different jurisdictions.

Distributed Generator's Proposed Solutions

No solutions are needed. The system integrator stated that the utility was cooperative and that the only problems seemed to be related to the utility's "learning curve."

Case #23 — 3-kW PV System in New England

Technology/size	Photovoltaic (3 kW)
Interconnected	Yes
Major Barrier	Business Practices—General
Barrier-Related Costs	None—Threatened Charges
Back-up Power Costs	Not Applicable

Background

This case involved a residential customer in New England who sought to install a 3-kW PV system, consisting of PV modules and three inverters, which were UL listed and complied with the IEEE P929 standard. The customer encountered a variety of technical, contractual, financial, and procedural barriers. The project was installed in 1999 after an eight-month delay.

In late 1997, the customer had received a flier in the mail from the utility stating that utility customers could interconnect renewable energy systems with a capacity of 10kW or less under the utility's net metering policy. The customer assumed that because the utility was advertising the service that interconnection would be straightforward.

Business Practice Barriers

Engineering Reviews; Insurance Requirements

When the customer contacted the utility, he was informed that the utility required the following: (1) an engineering study by utility engineers; (2) a detailed engineering plan; and (3) that the utility be listed as an additional insured on the homeowner's policy. The customer responded that these requirements were "ridiculous." He stated that residential customers who own combustion generators were not required to meet any of those requirements and asked why PV owners should be held to a different standard. The utility responded that it was because the utility was unable to keep track of residential customers that owned and operated combustion generators. The customer continued to argue against these requirements, and the utility rescinded the requirements.

Interconnection Fees

The customer was told that the utility required $1,000 to cover the costs of the customer's interconnection. The customer refused, again arguing that this was not a requirement placed on customers with generators. The utility rescinded its request.

Processing Requests for Interconnection and Conducting Inspections

The customer was informed that the utility required a site visit and a site review. Again the customer argued that this requirement was not imposed on homeowners that operate combustion generators. The utility dropped the requirements.

Technical Barriers

Safety Standards

The customer was also told that the utility required a disconnect switch for the entire house. The customer agreed to install the whole house disconnect switch. The customer has since re-wired the disconnect to isolate only the PV system. The utility inspected and approved the change, placing a lock on the disconnect switch.

In the end, the utility dropped all the requirements except the whole house disconnect. The customer reinstalled the system, and the utility inspected and approved it for free. The utility requested signage that identified the disconnect switch. The only cost to the customer (not-including the PV system) was the disconnect switch, the paperwork, and a $50 interconnection fee.

The customer stated that it took approximately 40 hours of his time over eight months to overcome the barriers he encountered. The customer was unable to generate approximately 2,500 kWh because of the delays in installing the system. At 14¢/kWh, the delays cost approximately $350.\

Distributed Generator's Proposed Solutions

The customer stated that, to his knowledge, his was the first renewable energy system that had been interconnected to his local utility.

The customer believed that the cumbersome interconnection procedures required by the utility was encouraging customers to install systems without utility notification or approval. This potentially could result in the installation of equipment that does not meet appropriate safety and power quality requirements.

The customer suggested that a superior solution would be to use a one-page interconnection agreement and a $50 fee to recover the utility's cost to review the agreement.

Case #24 — 3-kW PV System in California

Technology/size	Photovoltaic (3 kW)
Interconnected	Yes
Major Barrier	Business Practices—Request Processing and Fees
Barrier-Related Costs	None—Threatened Charges
Back-up Power Costs	Not Applicable

Background

In this case, a residential customer in California sought to install a 3-kW PV system and encountered numerous utility barriers. The principal obstacle was the utility's lack of familiarity with the state-mandated interconnection process established under the state's net metering law. This lack of familiarity resulted in the utility imposing requirements on the customer that it later had to rescind. The project was installed in the fall of 1998.

Business Practice Barriers

Making Contact; Processing Requests

The customer had difficulty locating the proper contact person at the utility. Once the customer found the correct utility contact person, it seemed that the utility had no experience with interconnection of systems eligible under the California net metering law, which had been in place since 1996. The customer also reported the utility to be uncooperative.

Negotiating interconnection with the utility ultimately took approximately 5 months.

Interconnection Fees

The utility initially requested an "installation fee" of $776.80. The customer suggested that the fees were excessive and perhaps even punitive (based on how the customer understood other California utilities to be handling interconnection of facilities eligible for net metering). On request, the utility itemized the fee as follows:

Materials	$344.96	Bare meter and purchasing and warehouse costs
Labor	$ 64.43	Meter installation
Equipment	$ 13.75	Transportation cost for service truck
Administrative	$143.87	Local engineering and administrative costs
Tax @37%	$209.79	The utility cites a tariff that states, "Any payments or contributions of facilities by applicant shall include an income tax component of contribution for state and federal income tax at the rate provided..."

The customer and utility negotiated these costs for approximately 10 days. The customer noted that the utility interconnection agreement stated that the utility could install dual meters at its own expense with the customer's consent. The customer requested that option and provided his consent. The utility stated that it was able to install a single bi-directional meter and that dual metering was not necessary to properly bill the customer, so the customer would be responsible for the bi-directional meter costs. The customer, wanting to move the process forward, sent the utility a check for the $776.80.

The customer contacted the California Energy Commission (CEC) for assistance. According to the customer, the utility's attitude appeared to change after it became clear that a staff person at the CEC was aware of the situation and was advising the customer. Approximately 15 days after the customer sent the check for the additional meter installation, the utility returned the check stating that the utility would not require a "meter installation fee." It also stated that the customer's existing meter was bi-directional and would be adequate for metering the customer's property including the PV system.

Contractual and Procedural Requirements for Interconnection

After the utility agreed that the customer's existing meter met the utility's requirements, the utility sent the customer an updated interconnection agreement and stated that the customer still needed an "Authorization to Interconnect and Operate in Parallel" after an "internal review" by the utility. The utility also stated that it was waiting to receive a copy of the inspection clearance from a jurisdictional authority (the local building inspector). The utility also stated that a utility representative must be present when the system was connected.

Insurance Requirements

The utility then requested to be named as an "additional insured party" on the customer's homeowner's insurance policy and stated that the interconnection could not take place until the customer provided written proof of the required insurance. The customer was then notified by a staff person at the CEC (who had been kept apprised of the negotiations) that the utility did not need to be listed as an additional insured party. Instead, the utility simply needed to be placed on the policy as a "notified party" in the event the policy is renewed or cancelled. The utility accepted this approach.

The customer then scheduled the interconnection, giving the utility the required notice.

Technical Barriers

Redundant Equipment Requirements

Four days later (and four days before the scheduled installation), the utility asked the customer to confirm a lockable, visible open disconnect switch between the inverter and the meter. The customer had installed a disconnect switch behind a junction box, and the utility did not accept this location. Initially the utility stated that the customer would need to pay for an additional disconnect. The customer complained to the CEC, which intervened on the customer's behalf.

The utility then offered to pay for the additional disconnect, provided that the customer gave the utility three estimates from licensed electrical contractors before the utility's approval of payment. The utility also stated that the new disconnect would need to be re-inspected by the county before the utility would approve the interconnect.

The customer responded by stating that he had informed the utility weeks earlier that he had installed a visible disconnect switch and that the utility had not responded until the "11th hour" regarding the need for something more than what the customer had already installed. The customer also complained that the utility had never before inquired as to what type of switch the customer had installed. The customer stated that he would accept the offer to have the utility pay for the special switch, but that he would not have the system bid by three contractors. He would simply have his existing contractor perform the work at a competitive price. The customer directed his contractor to fax the estimate to the utility. The customer postponed the interconnection, and again contacted the CEC for help. The utility accepted the contractor's bid and paid for the installation.

The customer responded, after discussions with the CEC, that under current law the interconnection agreement that had already been approved was all the customer needed, provided he gave the utility five working days notice prior to interconnection. The customer stated that under advice from the CEC, he would give the utility the five-day notice and would proceed without waiting for the utility's review process, or for additional approvals from the utility. The customer also noted that the inspection report from the local building inspector had been sent to the utility five to six weeks earlier.

Conducting Inspections

The customer then rescheduled the interconnection and notified the utility. The utility did not send a representative to attend the interconnection. Three or four months later, the utility inspected the system and apologized for the difficulties the customer had experienced, explaining that he was the first customer to interconnect in this fashion and that the utility was on a steep learning curve.

Business Practice Barriers

Insurance Requirements

The utility also imposed a requirement that the customer carry $200,000 in commercial liability insurance to cover potential liabilities from property damage or personal injury attributable to the PV system. The customer was a commercial farming operation that already carried commercial insurance in the required amount, so the utility's requirement did not impose any additional burden on this customer. The utility also required that it be listed as an "additional insured" on the customer's policy, which required the concurrence of the customer's insurer. The customer's insurer agreed to this condition.

During the course of the conversation with his insurer, however, the customer learned that the insurer does not provide commercial riders on standard homeowner policies and that it does not add "additional insured" to homeowner policies. Therefore, the enforcement of these insurance requirements could be a complete bar to the installation of PV systems on residential properties in this utility's service territory.

Finally, the customer reported that the utility had recently lifted the additional insured requirement for residential customers with homeowner's liability coverage. The $200,000 insurance requirement is still in effect.

Estimated Costs

The customer estimated that meeting utility interconnection requirements cost him $1,200 for the engineering study and the protective relays, plus $125 per year for the relay calibration. The customer further estimated that he had dedicated a total of approximately 200 hours over two separate six-month periods to meeting the utility's requirements and addressing the utility's concerns.

Moreover, the manufacturers of the customer's equipment were called on to provide wiring diagrams, engineering schematics, and other documentation to support the customer's efforts to resolve the utility's concerns. The customer was unable to estimate this time and expense.

Distributed Generator's Proposed Solutions

The customer suggested that inverter manufacturers design to a particular standard, with labels to indicate that the inverter meets that standard, which the utilities would be required to automatically accept.

The customer also suggested that part of the problem was the utility's lack of familiarity with small-scale, customer-owned generating facilities. Some of the problems he encountered would be resolved over time as utilities gained more experience with these facilities.

Case #26 — 300-Watt PV System in Pennsylvania

Technology/size	Photovoltaic (300 Watt)
Interconnected	No
Major Barrier	Business Practices
Barrier-Related Costs	$400
Back-up Power Costs	Not Known

Background

This simple case involved a resident of Pennsylvania whose PV contractor contacted the local utility about installing a 300-Watt integrated AC-solar-photovoltaic (PV) system (producing approximately 250 Watts AC). The principal barrier encountered by the customer was interconnection fees proposed by the utility that would have erased the equivalent of 10 years' energy savings from this small PV system.

The integrated AC PV system was one of several types of so-called "AC modules" that represent one of the most recent innovations in PV technology. Most PV systems consist of an array of multiple PV modules that are interconnected to the utility grid through a single inverter. Until recently, most inverters were sized to accommodate 2.5 kW to 5 kW of PV modules, roughly equivalent to the power needs of a standard residence. The price for complete systems of this size was approximately $25,000 to $40,000. Many potential customers interested in PV technology are unwilling or unable to afford these larger, whole-house systems.

An AC module, by contrast, consists of a single PV module with its own micro-inverter. These micro-inverters range in size from 100 Watts to 300 Watts.

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The attraction of AC modules is that they allow customers to invest in PV technology at prices starting as low as $900. Although the smallest systems will typically only offset a small percentage of a typical residential customer's electricity use (approximately two to four percent), they can be installed singly or in multiples to match the customer's budget and desired energy savings.

However, because the amount of electricity generated by an AC module is relatively modest, the potential market for these self-contained PV systems depends on simplified interconnection at a minimum cost. In this case, interconnection charges that would be insignificant for larger distributed generating facilities was prohibitive when imposed on these small-scale systems.

Business Practice Barriers

Interconnection Fees

This customer sought to install an integrated AC PV module in the service territory of an investor-owned utility. In accordance with the utility's rules, the customer was provided with an application form and asked to submit a $100 processing fee. In addition, the utility indicated that it would bill the customer for the actual costs "of processing the application and inspection of the facilities," although "in no event will the charge exceed $300."

These costs, which would be inconsequential for a larger generating facility, act as an effective bar to the commercialization of AC modules in the smaller installations for which they were designed. The AC module in this case, for example, is expected to produce approximately 400 kilowatt-hours (kWh) per year in a moderate solar energy environment, which represents approximately $40 per year in energy savings (assuming a retail price of 10¢/kWh). This means that the $100 application fee and the processing/inspection fee of up to $300 equals 2.5 years and 7.5 years of energy savings, respectively.

Another way of looking at these figures is that even if a 250-Watt PV system was given to a customer free of charge, the customer would have little incentive to install the system. The out-of-pocket cost to interconnect the system would require 10 years worth of electricity generation to break even, or much longer on a discounted present-value basis. In short, this case study suggests that for these small systems to become commercially viable interconnection must be essentially a "Plug & Play" proposition, which will enable these units to be installed, interconnected, and operated at a minimal cost.

Estimated Costs

The cost of the barriers was between $100 and $400, plus time spent by customer and manufacturer working with the utility on the application process and system inspection.

Distributed Generator's Proposed Solutions

The manufacturer noted that the integrated AC module and other micro-inverters now available on the market are fully compliant with safety and power quality standards developed for utility interconnection of PV systems, including the IEEE P929 and UL 1741 standards. The manufacturer's opinion was that compliance with these standards fully addresses legitimate safety and power quality concerns, and that no additional testing or inspection by the utility is necessary.

NEP4-14v8
14 pgs

Making Energy Efficiency a Priority to Reduce U.S. Energy Intensity

National Goals & Energy Intensity Tracking Components of Work Plan

NEP Implementation Focus Meeting
Prepared by Office of Planning, Analysis & Evaluation
August 10, 2001

Outline of Presentation

- **Products**
- **Process for implementing the recommendation**
  - Development of a system for tracking indicators of energy intensity
  - Development of national energy intensity goals
- **Framework for tracking changes in energy intensity**
  - Nested structure of energy intensity
  - Illustrative characteristics of indicators

Products

National energy intensity improvement goals for each energy sector	Web-based tracking system
• Industrial • Residential & Buildings • Transportation • Electricity • Identify technologies & rates of improvement to achieve the goals	• Provide an overall look at the energy efficiency picture • Information on energy intensity progress is available to all • Analytical effort to understand and trace key components of change in energy intensity trends

➢ **Credibility established with experts, private industry, and state and local governments**

- identify realistic intensity improvement goals
- identify technology opportunities & potential barriers in meeting goals
- gauge relative levels of expected contributions towards overall changes in national intensity trends

Recommendation Implementation Process 1

Intensity Indicators

- **Kickoff technical meeting with contractors, July 26 [EERE]**
- **5-pg. Context paper, Aug 2001 [PI prepare, EERE & OSTP review]**
  - Overview of national & sector intensity trends & key end-use components
  - Discussion of historical trends
  - Discussion of challenges to reducing energy intensity (e.g., modal transport shifts, lack of appreciable improvement in electricity generation efficiency since 1960)
- **Federal Register Notice, draft Oct. 15, 2001 [EERE prepare]**
  - Describe workshop & purpose

National Goals

- **Survey of goal statements, mid-October 2001**

  [EERE & Contractor, PI & OSTP review]
  - Review existing literature & current proposals on energy intensity improvement goals; also review available sector level studies of techno-economic potential

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Recommendation Implementation Process 2

Intensity Indicators

- **Methodology paper, Nov. 26, 2001 release on DOE web**
  [EERE & Contractors, OSTP & PI review]
  - Objectives, constraints, alternative methods & tradeoffs
  - Proposed methodology
- **Indicators Expert Workshop, Dec. 4, 2001 [EERE, with OSTP & PI involvement]**
  - e.g., experts from Harvard, RFF, Stanford, etc.
  - Potential users (e.g., DOE users, OSTP, OBM, NGOs & news media technical experts)
- **Analysis paper, Feb. 15, 2002 [EERE & Contractors, PI & OSTP review]**
  - from existing indicators studies, tease out autonomous intensity trends info

National Goals

- **Model technology implications different intensity levels, Nov. 30, 2001**
  [EERE & Contractors]
  - e.g., model different levels of intensity improvements for 2020 & 2050
  - assess implications for investment cost, VMT, roles of Govt. & private sector
- **Technology & Modeling Expert Workshop, Jan. 2002**
  [EERE, OSTO & PI involvement]

Recommendation Implementation Process 3

Intensity Indicators

- **Pilot tracking system, March 4, 2002 [EERE & Contractors, PI & OSTP review]**
  - Operated in a web environment
  - Assemble user group to test and validate, and report on experiences
- **Stakeholder Conference or other national forum, early March 2002 [EERE, PI & OSTP co-manage]**
  - Main objective: identify realistic national goals, link state & national goals, broader feedback on indicators tracking system & technology implications of different national goals
- **Report on conference, May 10, 2002 [EERE, PI, OSTP]**
- **Operational tracking system, July 2002 [EERE & Contractors]**

National Goals

- **Stakeholder Conference (or other national forum), early March 2002**

  [EERE, PI & OSTP co-manage]
  - Main objective: identify realistic national goals, link state & national goals, broader feedback from stakeholders on indicators tracking system and on technology implications of different national goals.

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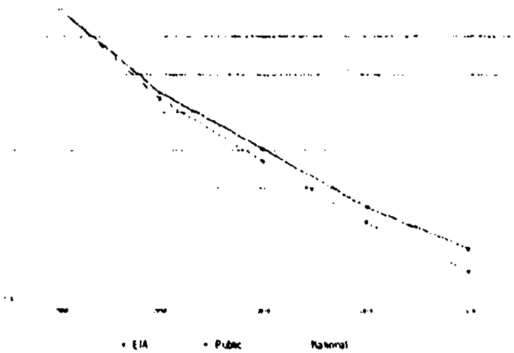
Elements of a National Energy Intensity Goal



- Builds on expected underlying improvements
- Based on private & public sector (federal, state, & local) contributions
- *DOE & EERE efficiency goals represent only a portion of the full national goal.*

Process for Implementing the Recommendation:

Working with State and Local Governments

- Identify potential markets by sector, by energy service demand, and by technology

- Identify efficiency gaps by technologies and by fuel types

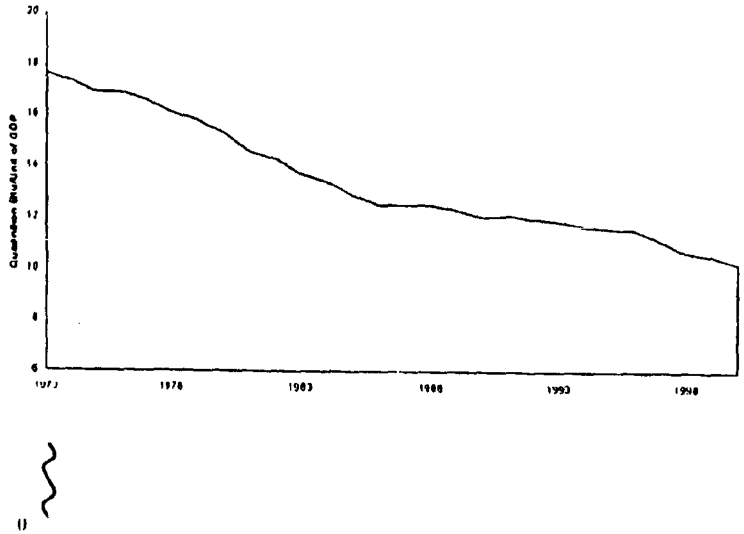
- Adopt a energy system approach to address energy intensity objectives in end-use sectors

- Evaluate potential economic and environmental benefits

- Analyze the level of program activities and efforts required to achieve goals

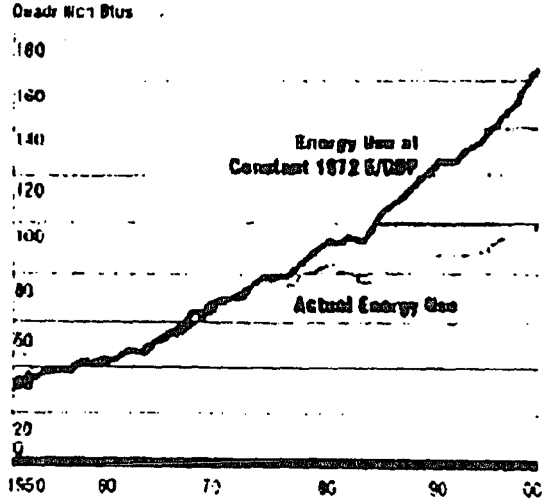
Energy Intensity & Savings

Aggregate Energy Intensity (Energy/GDP)



U.S. Economy is Less EnergyDependent

Figure 8-1
The U.S. Economy Is More Energy Efficient (Energy Intensity)
Primary Energy Use

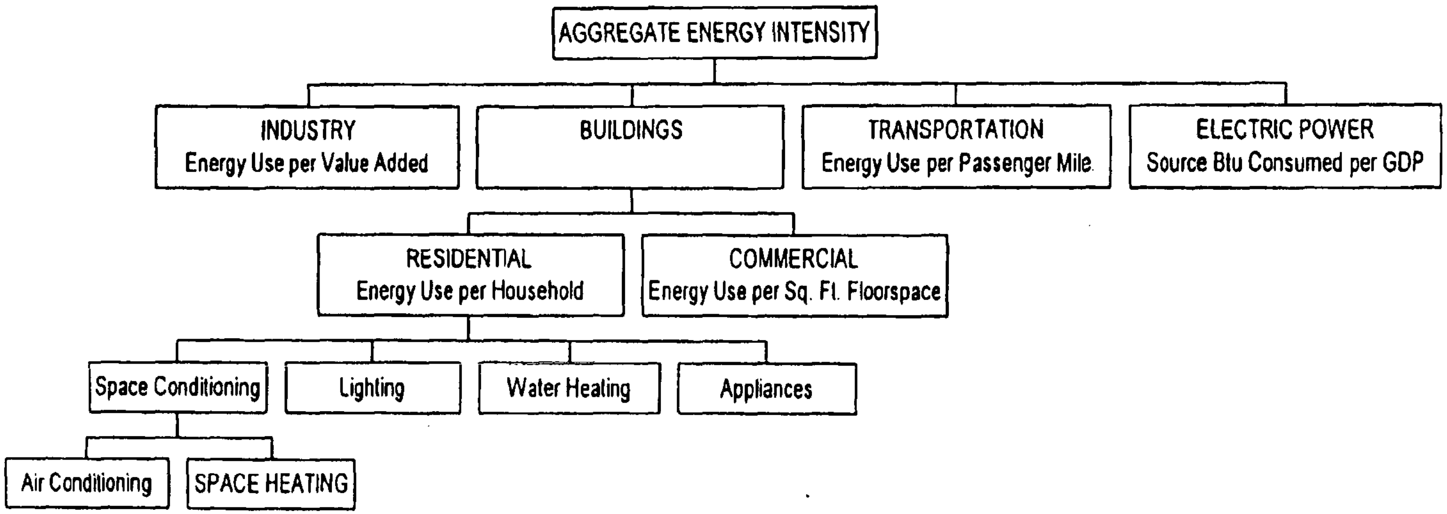


Example of Indicator Tracking

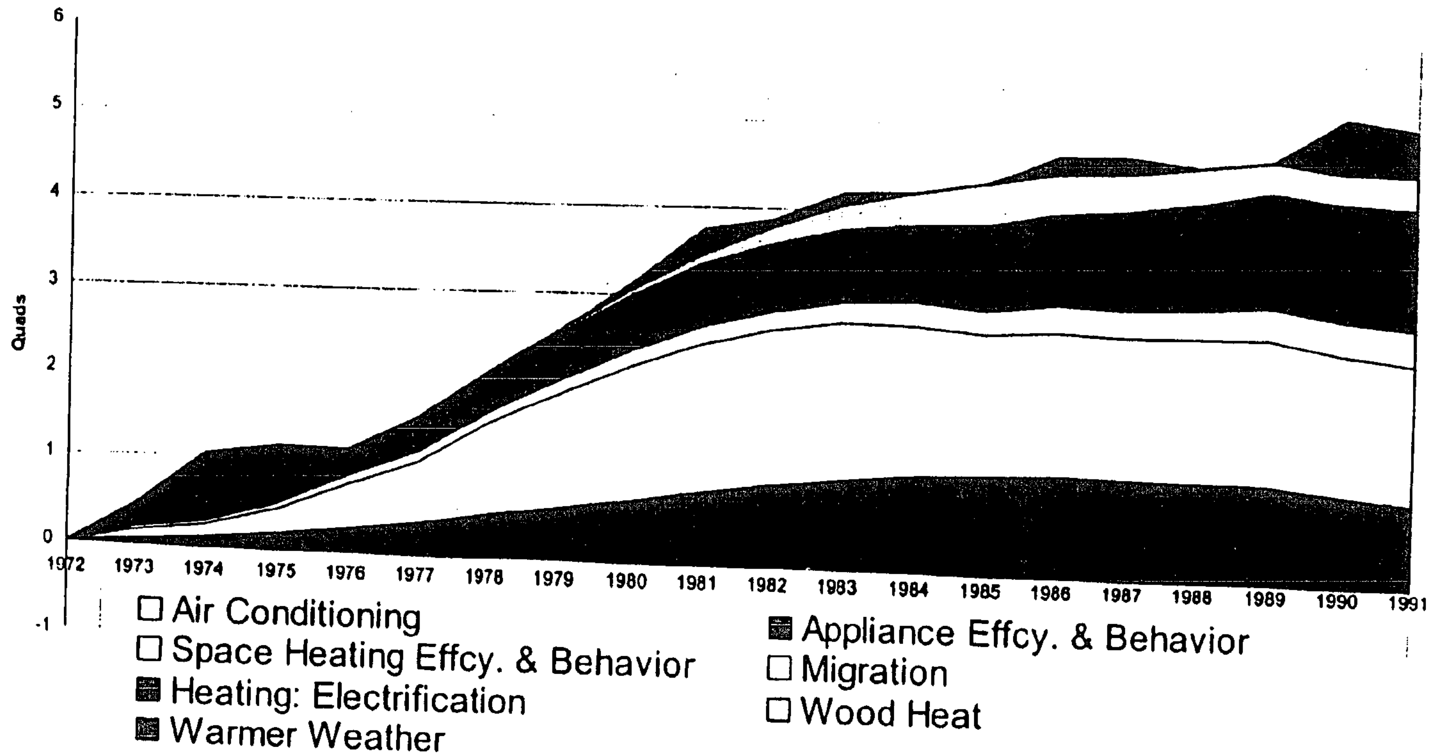
- For each sector, <u>Indicators Tracking</u> would report on
  - (1) changes in energy use and
  - (2) changes in the components of energy use (energy efficiency indicators per end-use breakdown, as well as contributions from activity, structure and weather effects)

- <u>Example</u>: Space-heat use & efficiency indicator (space heat energy per unit home floor space) -- captures shell retrofits, energy efficiency in new homes, efficient space heating equipment, changes in energy conservation behavior

Energy Intensity Breakout



Components of Delivered Energy Savings: Residential Sector



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Factors Directly Affected by Energy Price and Policy vs. Those That are Less Likely to be Affected (e.g. Structural & Other Factors)

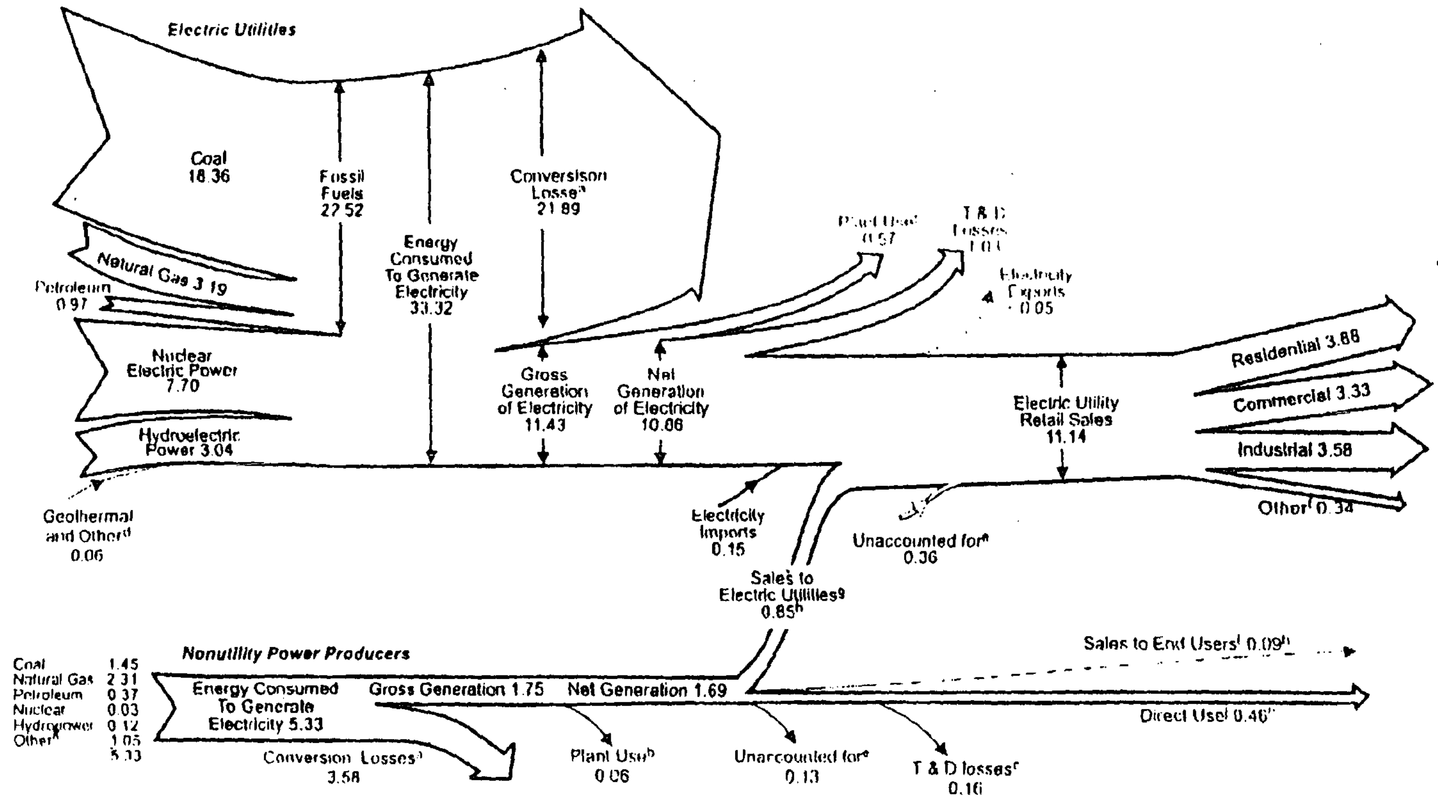
Sector	Energy Price & Policy Sensitive	Structural & Other Indirect Factors
Residential	Space heat use & efficiency Appliance use & efficiency	Size of homes Saturation of air-conditioned space in homes
Commercial	Efficiency of office equipment Shell retrofits	Geographic shift Building type shift
Industrial	Intensity change: heat & power Intensity change: materials	Compositional shift
Transportation	Vehicle efficiency	Shifts in mode of transport Vehicle load factors
Electric Power	Electricity generation & transmission efficiency	

Desirable Attributes of Indicators

- ✓ **Focus on tracking trends over time, with annual updates**
- ✓ **Credible**
  - represent what is being measured; credible primary & secondary data sources, be verifiable
- ✓ **Address user needs**
  - relates to national goals; attributable to EERE program actions (e.g., distinguish indicators that are price & policy sensitive from those associated with structural & other changes)
- ✓ **Understandable & transparent**
  - clearly defined & consistent; explainable; measurable; data consistency over time)
- ✓ **Practical (based on existing information sources)**
  - based on existing information sources; data consistency over time; can get timely data
- ✓ **Widely recognized**

Release.

Typical Electricity Losses



Source: U.S. DOE/EIA *Annual Energy Review 1999*

FOR TESTIMONY

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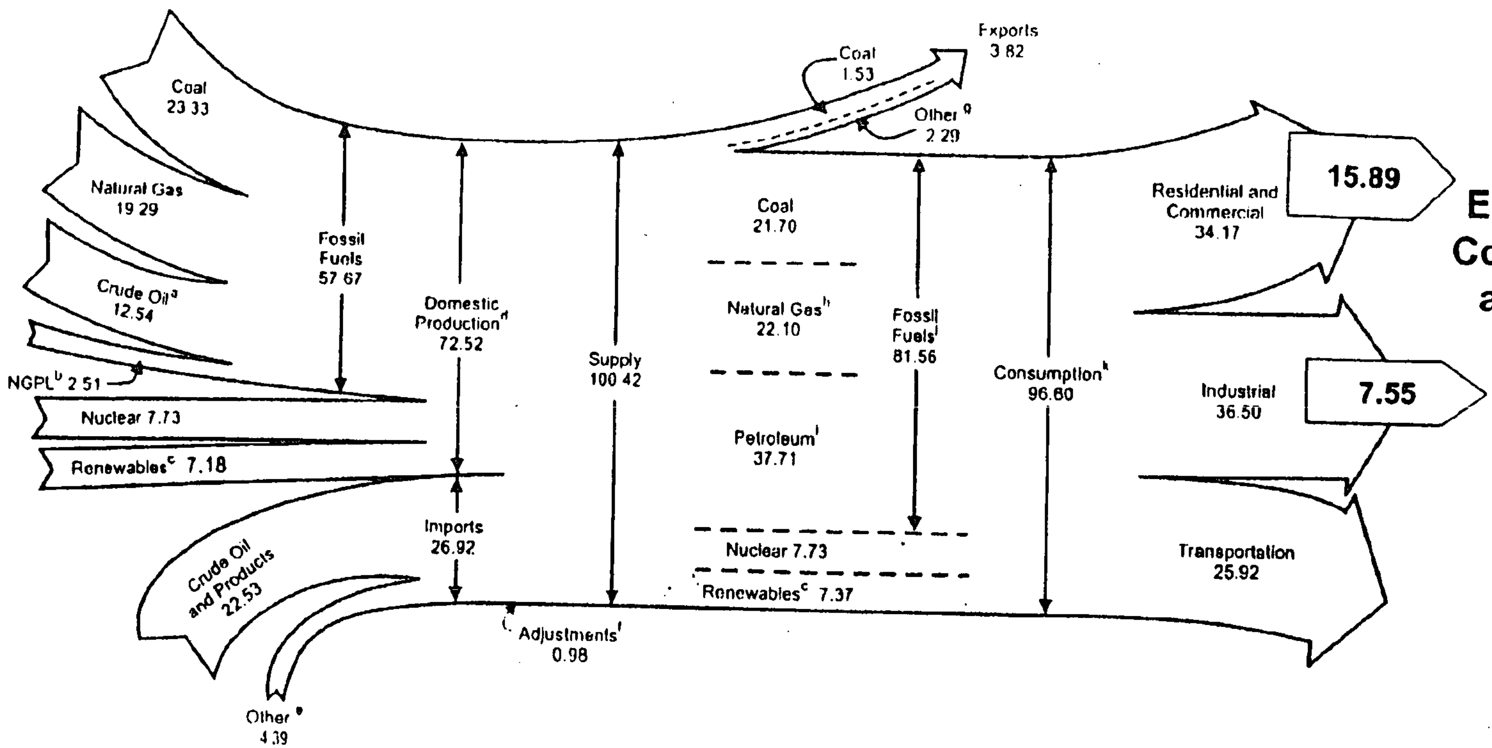
Typical Energy Flows in the U.S.



Source: U.S. DOE/EIA *Annual Energy Review 1999*

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release

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NEP Action - TPK. x/s

4??s Release

SELECTED PASSAGES FROM THE NATIONAL ENERGY POLICY			
COMMENT	PAGE	SECTOR	IMPLICATION
Americans share the goal of energy conservation. The best way of meeting this goal is to increase energy efficiency by applying new technology - raising productivity, reducing waste, and trimming costs. . . . Public policy can and should encourage energy conservation.	xi	OIT, OTT, BTS, FEMP	
We do not accept the false choice between environmental protection and energy production. An integrated approach to policy can yield a cleaner environment, a stronger economy, and a sufficient supply of energy for our future.	xiv	ALL	
An increased rate of improvement in energy efficiency can have a large impact on energy supply and infrastructure needs, reducing the need for new power plants and other energy resources, along with reduced stress on the energy supply infrastructure.	1.4	OIT, OTT, BTS, FEMP	
Load management is the ability to adjust energy loads to reflect immediate supply conditions. In the very short term, direct appeals for conservation can ease strained energy supply markets for a time. Over the longer run, the ability to adjust demand on an as-needed basis can be an important source of energy reserves, resulting in lower energy bills for participating customers.	1.4	OIT, OTT, BTS, FEMP	
Development of alternative fuels such as ethanol and other biofuels . . . , natural gas, and electricity, can help diversify the transportation sector that is so reliant on oil.	1.14	OPT, OTT	
Reforms to the federal alternative fuels program could promote alternative fuels use, such as expanding the development of an alternative fuels infrastructure.	1.14	OPT, OTT	
Improved energy efficiency strengthens energy security.	2.8	OIT, OTT, BTS, FEMP	
The federal government can promote energy efficiency and conservation by including the dissemination of timely and accurate information regarding the energy use of consumers' purchases, setting standards for more energy efficient products, and encouraging industry to develop more efficient products.	4.1	OIT, OTT, BTS	
The federal government can also promote energy efficiency and conservation through programs like the Energy Star program, and search for more innovative technologies that improve efficiency and conservation through research and development.	4.1	OIT, OTT, BTS	

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Unless consumers are informed about the price of energy, they may not have the incentive to select the most energy efficient product.	4.4	OIT, OTT, BTS	
Energy efficiency can also be improved by the establishment of minimum energy efficiency standards.	4.5	OIT, OTT, BTS, FEMP	
Because many manufacturing and farming operations are highly specialized, they need specific information on energy-saving opportunities to effectively respond to energy price signals and supply problems.	4.8	OIT	
Opportunities for reducing oil demand in the transportation sector include increasing conservation, vehicle efficiency, and alternative fuels.	4.10	OTT	
[A]n increase in the average fuel economy of the on-road vehicle fleet by three miles per gallon would save one million barrels of oil a day, or about half the global shortfall between supply and demand that triggered the oil price increases since 1998.	4.10	OTT	
A recent analysis indicates that the fuel economy of a typical automobile could be enhanced by 60 percent by increasing engine and transmission efficiency and reducing vehicle mass by about 15 percent.	4.10	OTT	
A sound national energy policy should encourage a clean and diverse portfolio of domestic energy supplies.	6.1	OPT	
Renewable energy can help provide for our future needs by harnessing abundant, naturally occurring sources of energy, such as the sun, the wind, geothermal heat, and biomass.	6.1	OPT	
Renewable and alternative energy supplies not only help diversify our energy portfolio; they do so with few adverse environmental impacts.	6.1	OPT	
Significant cost reductions must be achieved before fuel cells will be competitive with internal combustion engines, and the size and weight of fuel cell systems must be reduced even more to accommodate vehicle packaging requirements.	6.11	OPT, OTT	
[DER] are modular and can be constructed rapidly, adding an immediate source of new power in areas that otherwise might face a shortfall. Distributed renewable energy resources can enhance the reliability and quality of power.	6.14	OPT	
Renewable technologies can help provide insurance against price volatility. In addition, many renewable technologies can help industry achieve compliance with the Clean Air Act and other environmental regulations. In some cases, renewables can be more readily located in urban areas whose air quality does not meet regulatory requirements.	6.14	OPT, OIT	

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[T]he extent to which [non-hydropower renewables] are successfully tapped will depend in large part on continued technological development.	6.14	OPT	
For renewable and alternative energy to play a greater role in meeting our energy demands, these sources of generation must be able to integrate into our existing distribution system. The tools that form the necessary interface between distributed energy systems and the grid need to be less expensive, faster, more reliable, and more compact.	6.14	OPT	
Renewable and alternative energy technologies, such as wind energy and combined heat and power could be significantly expanded, given today's technologies. They could be further expanded with added investment in technology.	6.14	OPT	
[W]ind energy could be developed that could be adapted to sites with lower wind speeds than is feasible today.	6.14	OPT	
Combined heat and power in buildings offers great potential for increased system efficiencies and lower costs.	6.14	OPT	
New developments in microturbine and fuel cell technologies are also highly promising.	6.15	OPT	
Performance improvements of other technologies, such as photovoltaic systems, would facilitate much wider use.	6.15	OPT	
In addition to technological performance, attention to several key market and regulatory constraints would accelerate the development and use of renewable and alternative energy in the marketplace.	6.15	OPT	
Because many renewable and alternative energy technologies do not fit into traditional regulatory categories, they are often subject to competing regulatory requirements or to requirements that were never designed to address them. For example, much of the current Clean Air Act does not specifically address the use of new, more efficient renewable energy technologies. Consequently, the Act does not provide significant incentives for the development of such technologies.	6.15	OPT	
The lack of interconnection standards or guidelines for electricity supply and loads impedes the use of distributed energy technologies. As a result, developers of small, renewable energy projects must negotiate interconnection agreements on a site-by-site basis with local distribution companies that are often opposed to distributed energy projects because of the increased competition. Although a few states have established interconnection standards, there is no national standard to facilitate development of distributed energy.	6.15	OPT	

New combined heat and power facilities may face air permitting hurdles when they replace marginally dirty boilers. The Clean Air Act does not recognize the pollution prevention benefits of the increased efficiency of combined heat and power units. At the same time, these combined heat and power investments are taxed at the industry's tax rate, not at the rate they would receive if they were considered part of the utility sector for tax purposes.	6.15	OPT	
The lack of infrastructure for alternative fuels is a major obstacle to consumer acceptance of alternative fuels and the purchase of alternative fuel vehicles. It is also one of the main reasons why most alternative fuel vehicles actually operate on petroleum fuels, such as gasoline and diesel. In addition, a considerable enlargement of ethanol production and distribution capacity would be required to expand beyond their current base in the Midwest in order to increase use of ethanol-blended fuels.	6.16	OPT, OTT	
The use of natural gas or electricity for vehicles requires enhancements to these distribution systems, such as compression stations for natural gas. While many alternative fuels can be shipped by pipeline, they may require separation within the pipeline to avoid mixing different energy products. Geographically dispersed renewable energy plants often face significant transmission barriers, including unfavorable grid schedule policies and increased embedded costs.	6.16	OPT, OTT	
Uncertainty regarding the tax treatment of these technologies and energy sources can discourage long-term investment. Though existing tax credits provide an incentive for investing in some types of renewable energy, the limited scope of the credit and its frequent expiration discourages investment	6.16	OPT	
The first step toward a sound international energy policy is to use our own capability to produce, process, and transport the energy resources we need in an efficient and environmentally sustainable manner.	6.1	OPT, PBM	

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Florida House of Representatives

Jerry Paul
Deputy Majority Whip
Representative, District 71

4456 Tamiami Trail, Suite B-14
Port Charlotte, FL 33980-2136
(941) 764-1100
(800) 729-1101

319 The Capitol
402 South Monroe Street
Tallahassee, FL 32399-1300
(850) 488-0060

May 25, 2001

The Honorable Spencer Abraham
Secretary
U.S. Department of Energy
1000 Independence Ave., S.W.
Washington, DC 20585

Dear Mr. Secretary:

Enclosed is an article appearing in the *Charlotte Sun Herald* in Port Charlotte, Florida relating to our energy policy.

As a member of our Southern State's Energy Board, I was pleased to provide input to Vice President Cheney's Energy Task Force. As a former power plant engineer, nuclear engineer, and State Legislator I cannot overstate the extent to which I am pleased with the responsible, accurate and comprehensive recommendations of the Task Force Report.

I would welcome an opportunity to assist you in any way on issues relating to our nation's energy policy.

Please call on me any time.

Respectfully,

Jerry Paul

Jerry Paul
District 71

Enclosure

JP:jh

Paul: Nuclear needed

Says he'll use education to provide oversight

Charlotte Sun 5-23-01

By GREG MARTIN
Staff Writer

President George Bush's administration contends that nuclear power should be included among the solutions to address the nation's "energy crisis" — and Florida should be no exception, according to state Rep. Jerry Paul, R-Port Charlotte.

However, Florida Power and Light officials said in a recent annual report that Florida doesn't face an energy crisis. FPL plans to increase its generating capacity by 33 percent over the next 10 years, "using environmentally friendly natural-gas technology," according to the report.

PAUL

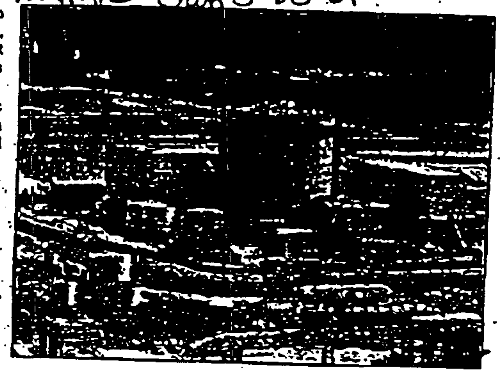
Rep. Paul, however, cited the fact that nuclear power has proven to be "the safest and cheapest" source of electrical power, compared to coal, gas and oil-fired plants.

"We've got to make sure Florida does not get trapped in a California scenario," Paul said. "If we don't have the capacity then our electric rates will go up.

"Really, the touchstone in all of this, the primary goal, has got to be to keep the cost of electrical power as low as possible."

Paul, a member of the state's House Committee on Utilities and Telecommunications, was appointed this year by House Speaker Tom Feeney to the Southern States Energy Board. Florida Sen. Tom Lee,

Please see PAUL, page 8



The Crystal River nuclear power plant is one of three nuclear power generating stations in Florida.

Photo provided

★ PAUL

From page 1

R-Brandon, is the state's other representative on the board.

Paul was reached in Miami Tuesday where he was attending a two-day meeting of the SSE board to discuss the hurdles to nuclear power projects in the Southeastern United States.

Paul said he hopes to use his educational background to oversee the expansion of nuclear power in Florida. The Port Charlotte attorney earned degrees in marine engineering at the Merchant Marine Academy in Maine in 1988, and in nuclear engineering at the University of Florida in 1991.

"We're talking about the states' role in overseeing our nuclear industry," Paul said.

One of the biggest issues for the state is the storage of spent fuel rods, Paul said.

In Florida, those hazardous materials have been indefinitely stored in pools on the sites of FPL's three nuclear power generating stations.

Those stations include: two reactors at Turkey Point near Homestead, two reactors at St. Lucie and one reactor at Crystal River.

Board members from other states also discussed their concerns, including how to dispose of radioactive wastes from nuclear weapons facilities, Paul said. Florida currently has no such facilities.

Paul argues that nuclear materials are naturally found in the ground and could be stored there. One factor that has held the industry back has been the federal government's reluctance to establish a national nuclear waste storage facility, Paul said.

Former President Jimmy Carter closed two facilities that reprocessed spent fuel rods so they could be fissioned a second time, Paul said.

"He forced every state to basically store its own waste," Paul said. "That cost us all a lot."

Some 20 years ago, Congress vowed to establish a nuclear storage facility by the year 2000 at Yucca Mountain, Utah. However, that facility is currently 10 years behind schedule, according to Paul.

Paul said Florida currently produces about 40,000 megawatts of power, with 20 percent derived from nuclear power.

The state has a "deficit of about 13,000 megawatts" due to growth projections and increased use of computer technology, he said.

To avoid a crisis like California's, Florida needs to diversify its power sources, Paul said. California not only depended heavily on natural gas, but it also was blocked by "extremist groups" from building new power plants for the past 10 years, Paul said.

However, Paul emphasized that Florida needs to first promote energy conservation and alternative sources such as wind, solar and "biomass" fuels.

After nuclear power, the next cheapest is coal. But coal pollutes the air with sulfur dioxide, Paul noted. Natural gas is cleaner, but Florida would require pipelines to get the gas, he added.

"There is no free lunch," he said. "It is costing us a lot. And there is an environmental toll."

However, FPL, in an annual report filed with the Public Service Commission in April, projected a 20-percent generating reserve margin for this summer, assuring its customers that there would be a sufficient supply of electricity.

Also, FPL's report outlines its 10-year plan to increase capacity by 33 percent using natural gas.

A pipeline has also been recently permitted to run from Texas through the Gulf of Mexico to Port Manatee. The pipeline will then cross the state to Fort Pierce with a spur to the south.

"Unlike California, Florida customers enjoy an adequate supply of electricity," said FPL President Paul Evanson. "Our expansion program reflects our commitment to maintain sufficient reserves while remaining one of the cleanest utilities in the country."

You can e-mail Greg Martin at gmartin@sun-herald.com

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IPAA
America's Oil & Gas Producers

Barry Russell
President

March 7, 2001

2001-006235 Mar 8 A 7:23

The Honorable Spencer Abraham
United States Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Secretary:

On behalf of the 7,000 independent oil and natural gas producers from across the country, I am pleased to invite you to speak at the Midyear Meeting of the Independent Petroleum Association of America (IPAA). Our meeting will be held at the Keystone Resort in Keystone, CO, June 21-23, 2001. Approximately 500 executive level independent oil and natural gas producers from across the nation are expected to attend.

Addressing the nation's clear energy supply problems has been the ongoing purpose of the IPAA. It is a task that the Bush Administration has undertaken with a full recognition of its importance both to national security and a healthy economy. By the time of our meeting the President's energy task force will have completed its assessments and provided recommendations. We would like to ask you to present the scope of these efforts and their status to our members.

We would like to find a time slot that works with your schedule for you to be our keynote speaker on either Friday, June 22 or Saturday, June 23.

LuAnne Tyler, in our Meetings Department, will contact your scheduler to confirm your availability. Until then, should your office need to contact LuAnne, she can be reached at (202) 857-4722.

We hope your schedule permits your participation. Thank you for your consideration.

Sincerely,

Barry Russell
President

BR/lt

Independent Petroleum Association of America • 1101 Sixteenth Street, N.W. • Washington, D.C. 20036
202-857-4722 • Fax 202-857-4799 • www.ipaa.org

23487

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ipaa
America's Oil & Gas Producers

fax

586 4403

From: LuAnne Tyler

To: Honorable Spencer Abraham

Date: 3-7-01

Re: speaking at IPAA's midyear meeting

Number of pages following cover sheet: 1

Comments:

Independent Petroleum Association of America 1101 16th Street, N.W., Washington, DC 20036
(202) 857-4722 ♦ Fax (202) 857-4799 ♦ www.ipaa.org

CONGRESSWOMAN
ROSA L. DELAURO
FAX TRANSMISSION

To: Secretary Abraham **Date:** 3/23/01

Fax #: 586-7644 **Pages:** 2

From: 2001-007915 Mar 23 A 11:36

Comments:

★ 2262 Rayburn Building ★ Washington, DC 20515 ★
★ Phone: (202) 225-3661 ★ Fax: (202) 225-4890 ★

23489

Congress of the United States
Washington, DC 20515

March 21, 2001

The Honorable Spencer Abraham
Secretary of Energy
Forrestal Building
Washington, D.C. 20585

Dear Secretary Abraham:

As you are aware, our nation is confronting high energy prices and unreliable energy supplies that threaten to slow economic growth and have the potential to produce further energy disruptions this Spring and Summer. In an effort to adequately address this problem, we would like to invite you to meet with the Democratic Caucus Energy Task Force next week to discuss the current energy situation and the Administration's apparent effort to overhaul the national energy policy.

As committed leaders on energy issues in the Congress, we are concerned about the position the Administration has taken in recent days. Americans across the country are facing soaring gasoline prices at tl pump, natural gas prices that have more than tripled, and electricity costs that have been volatile all over the country, particularly the West coast. As a result, home heating bills have increased by as much as three fold from last year's extremely high prices.

The Democratic Caucus Energy Task Force is moving closer to developing a comprehensive energ policy, and we strongly believe that we must be mindful of both short-term and long-term needs. Adopting policy that strengthens our economy, protects our environment, and keeps our nation secure is our first pri We would appreciate the opportunity to meet with you and hear from you about your view of the current situation, as well as discuss with you in depth about the proposed budget for the Department of Energy.

We look forward to finding common ground with you and hope that you will be able to join us. confirm with Soña Garcia at the Democratic Caucus at 226-3210.

Sincerely,

Richard Gephardt

Frank Pallone

Charlie

23490

John F. Tierney	[illegible]
[illegible]	[illegible]
John W. Olver	Joe Baca
Ron Kind	[illegible]
Charles B. Rangel	Bob Filner
Edward J. Markey	Anna G. Eshoo
[illegible]	Tim Holden
Jim Oberstar	