Excess Capacity from LADWP Control Area
(LADWP, Glendale, Burbank)
Summer 2001

	1 in 2	1 in 5	1 in 10
Total Load (CEC Draft Demand Forecast 10/16/2000)	6,169	6,471	6,533
LADWP DSM Program	(10)		
Sales			
LADWP to CDWR	77		
LADWP to TID	51		
	6,287	6,589	6,651
(In-State and Out-of-State) Thermal			
LADWP (LADWP 2000 Integrated Resource Plan)	5,170		
Burbank	313		
Glendale	297		
Self Generation - in LADWP Control Area	338		
	6,118		
Allowance for outages (6%)	(367)		
Total	5,751		
LADWP Hydro	1,948		
Firm Contracts and Entitlements			
BPA to Burbank - Glendale	130		
Portland General Electric - Burbank - Glendale	80		
Burbank Hoover Entitlement	20		
Glendale Hoover Entitlement	20		
	250		
Total Resources	7,949		
Total Load + 7% Reserve	6,727	7,050	7,116
Potential Excess Capacity to Sell to CA ISO	1,222	898	832

New Generation Additions - Other Western States

On-line as of August 1st	2001	2002	2003	2004	Total
Baja Mexico					
Net New Adds/Retirements	612	419	1,079	0	**2,110**
Arizona, Nevada, New Mexico					
Net New Adds/Retirements	1,526	960	4,473	4,036	**10,995**
Northwest					
Net New Adds/Retirements	465	1,507	460	2,697	**5,129**
Rocky Mountains					
Net New Adds/Retirements	643	80	282	0	**1,005**
Alberta, British Columbia					
Net New Adds/Retirements	821	250	661	(216)	**1,516**
Total	**4,067**	**3,216**	**6,955**	**6,517**	**20,755**

Prepared by CEC Electricity Analysis Office, 11/20/00

216

California Summer 2001
Forecasted Peak Demand - Resource Balance
(in megawatts)

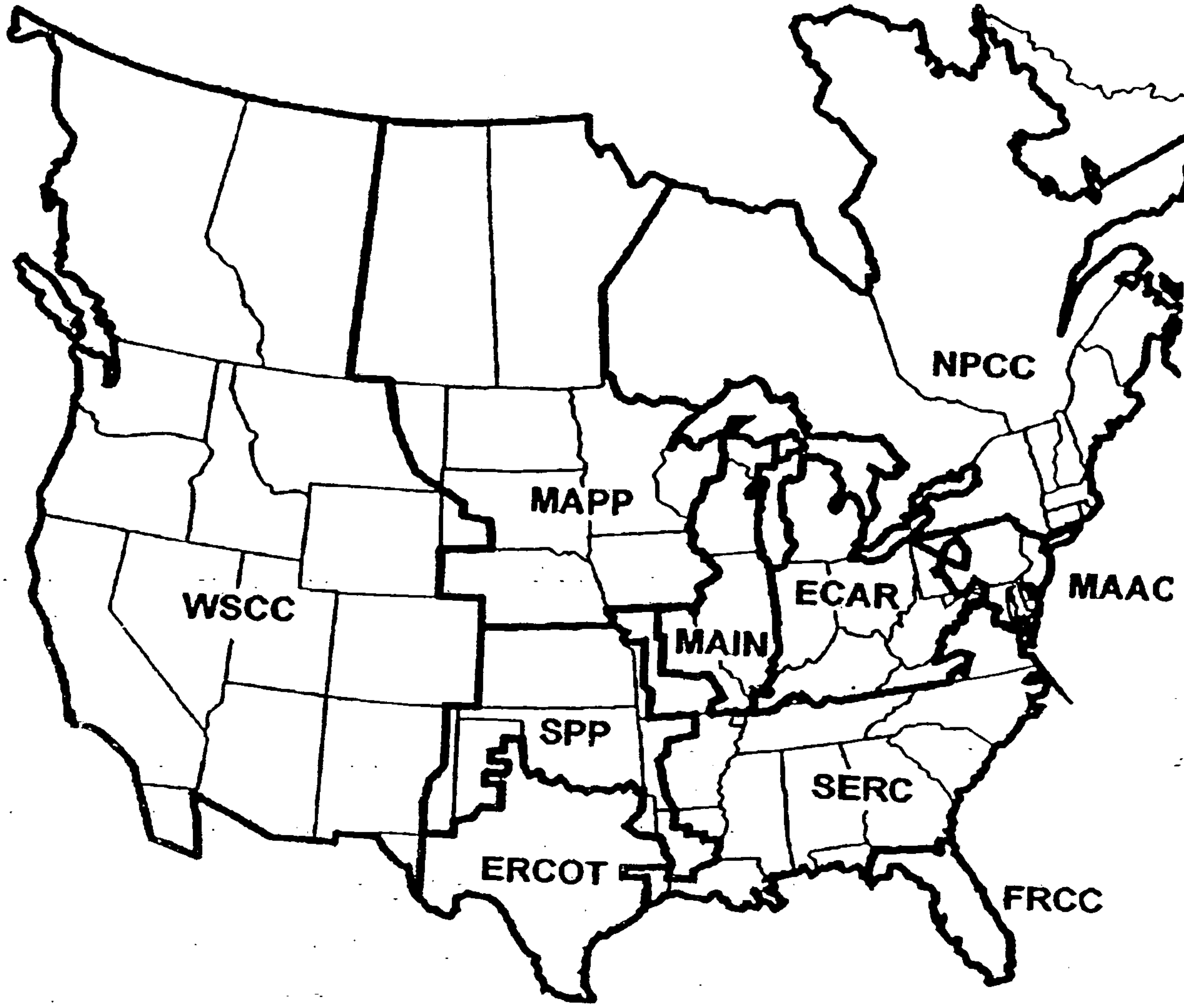
Temperature Probability	1-in-10	
Peak Demand + 7% Reserve	**61,125**	Incl. anticipated growth
Existing Resources:		
• Existing ISO Control Area Resources	45,025	
• Net Imports ISO Control Area	4,834	Includes Pacific Northwest
• LADWP Control Area Resources	8,198	
• Imperial Irrigation District	875	
• Far North - Eastern Sierras	277	
Total Existing Resources	**59,209**	
Expected Outages	-3,050 *	

* Historic average. Current outages are running 250% above average.

Resources Available to Meet Load	**-4,966**	
Additional Resources with On-Line Potential for July 2001:		
• Approved CEC Projects	1,262	
• SMUD McLellan CT Upgrade	22	
• ISO Peaking Facilities	1,133	
• Renewable Energy Projects	80	
• Rerate / Restart of Existing Thermal And Renewable Projects	1,244	
Potential Resources Existing Projects	**3,741**	
New Generation with On-Line Potential for July 2001:		
Emergency Peaking Facilities	1,000	
CEC Approval Pending	45	(United Golden Gate)
LADWP Harbor-Valley	267	
New Renewables / Distrib. Gen.	?	
Total New Generation Identified	**1,312**	
TOTAL GENERATION ADDITIONS SUMMER 2001	**5,053**	

Source: CA Energy Commission and Electricity Oversight Board February 8, 2001

217



http://www.nerc.com/regional/nercmapb&w.jpg

WATT FRIENDS WE HAVE

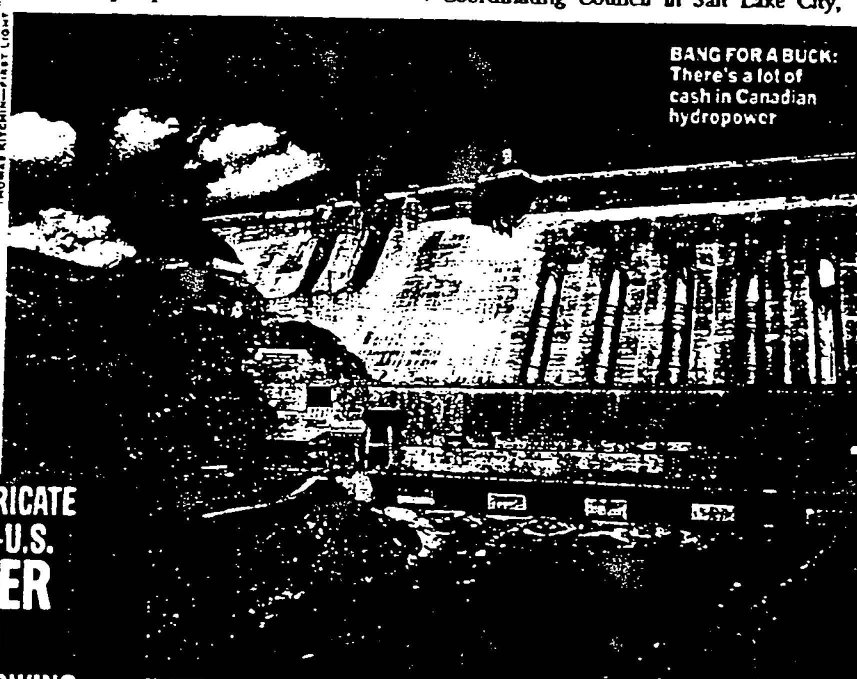
The California power crisis is proving to be a lucrative deal for our Canadian neighbors—and also a looming problem

By STEPHEN HANDELMAN

WHEN THE LIGHTS WENT OUT IN California last month, cash registers rang up north. In one critical 24-hour period on Jan. 18, British Columbia Hydro supplied more than one-third of the power desperate Californians needed to stave off a statewide blackout. The rescue didn't come cheap: the utility may have earned $3 million from the deal. "It's been a windfall," admits B.C. Hydro spokesman Wayne Cousins.

In the past seven months, B.C. Hydro has earned more than $700 million by selling power to energy-starved U.S. buyers—more than twice the $290 million earned from U.S. sales in the previous fiscal year. But this bounty hasn't come worry free. The intricate Canada-U.S. grid that links energy producers and consumers—and that makes it so profitable for B.C. Hydro to transmit power south—is in growing disarray. The consequences could be even higher prices and more uncertain supplies for Canadians as well as Americans. "We need a stable energy system on the continent," says Ray Hart, deputy director of the Department of California Water Resources. "I don't know if we'll get it." In particular, rising doubts about deregulation could impede Canadian plans to finance increased energy production, which in turn could help the U.S. avoid blackout.

Canada and the U.S. are in a kind of energy symbiosis. In 1999 Canada exported more than 38 million MW hours, but the number has reached as high as 50 million in recent years. In turn, U.S. demand is an important factor in building many Canadian energy projects. The hunger for power in the Western U.S. spurred plans to build more than 4,000 MW of new generating capacity in Alberta over the next five years, and a dedicated transmission line south to capitalize on American demand has also been on the provincial wish list. Similarly, Ontario and Quebec are counting on becoming bigger players in the U.S. market to generate profits needed to build plants at home. "No one can stay aloof from this market," says an Ontario Power Generation official. "You can't just integrate on one level. You have to work out how price, supply and environmental issues fit together." But the goals depend on an upsurge in U.S. power-grid investment that can be assured only by more complete deregulation of energy markets. The aftershocks from California place that prospect in doubt.



THOMAS KITCHIN—FIRST LIGHT

BANG FOR A BUCK: There's a lot of cash in Canadian hydropower

THE INTRICATE CANADA-U.S. POWER GRID IS IN GROWING DISARRAY

The current grid, the result of nearly a century of evolution, was developed to distribute electricity in an age when most production was run by states and provinces. Today a haphazard quilt of regimes governs transmission across thousands of miles of wire. Ontario, still contemplating deregulation, shares power with New York State, which is fully deregulated, and with Michigan, which is not. A huge transmission line from James Bay in northern Quebec can carry 2,000 MW of power south, but when the juice reaches the grid to New England, U.S. wires are capable of transmitting only 1,500 MW. "There's a tremendous need for the U.S. to spend more money on its part of the power grid if we want this market to work," says Thierry Candal, vice president for production at Hydro Quebec.

Some experts say a continental market for electricity, similar to the one that exists for oil and gas, is the eventual solution. But even without a grand plan to support that aim, moves are afoot to tinker with the existing situation. By next year, large regional transmission organizations (RTOs) will be in place across North America to remove some of the jurisdictional clutter. "Right now, if you want to ship power from El Paso [Texas] to B.C., you have to settle 10 or 12 different contracts," says Dennis Eyre, executive director of the Western Systems Coordinating Council in Salt Lake City, Utah, an organization that groups producers and suppliers in 14 Western states, plus British Columbia and Alberta, and Baja California in Mexico. "Now there will just be three organizations in our region." Eyre acknowledges that RTOs would not have prevented California's plunge into darkness, but they "will begin to get the market together over the next several years."

By then, new technology such as fiber-optic control systems and advanced high-speed transmission lines may help bind the wobbly system together. "Our vision is really a seamless cross-border market for electricity," says Hydro Quebec's Candal. That's a lot better, and a lot harder to achieve, than a quick profit on calamity. ■

ECONOMIC OPPORTUNITY STUDIES
400 NORTH CAPITOL STREET, SUITE G-80, WASHINGTON, D.C. 20001
Tel. (202) 628 4900 *Fax* (202) 393 1831 *E-mail* eori@earthlink.net

2/9

HIGHLIGHTS

The Winter Energy Outlook for the Poor

Using the most recent fuel price projections of the Department of Energy (DOE) and assuming weather is normal, most of the nation's 27 million low and moderate-income consumers will face winter fuel bills that will exceed 25% of their entire income for six winter months.

Among the findings:

- Winter fuel bills for heating alone will average nearly $1,000 for fuel oil users and nearly $800 for natural gas-heated homes. Combined with basic electric bills, costs will exceed one quarter of the monthly incomes of oil and gas heat users.
- For the entire year 2000 and fall of 2001, all energy bills to fuel oil users will average $2306 combined, or 26% of their annual incomes. Natural gas users who are low-income can expect annual bills for all fuels that total just under $2000, devouring, on average, 22% of their incomes.
- The average for all low-income families taken together is lower for only the homes heating with oil and gas, but their bills will average about $1,700, the equivalent of 19 percent of their entire household budget.
- By contrast, the other 74 million U.S. households will spend, on average, between 4 and 5 percent of their income on energy bills, a figure more than the three to four percent they spent in the past few years, but far less than the burden on the poor. These figures represent a dramatic change from past winters because of higher prices and colder, i.e. normal, weather which are part of the calculations.
- The Northeast and Midwest will experience the largest increases because natural gas and fuel oil price changes are the most dramatic. DOE predicts winter oil heat bills will be 35 percent above the 1999-2000 winter and 65 percent above 1997-1998; winter natural gas bills will be 50 percent higher than last year; the study shows that the low-income population will experience even larger increases, 59% for gas bills in the Midwest and 43% for oil in the Northeast.
- As a group, all 27 million low-income families will be billed nearly $45 billion for residential energy between October, 2000 and next September. The federal government has made $1.85 billion available for payment assistance and $153 million for Weatherization conservation measures in low-income housing for the same period.

Economic Opportunity Studies (EOS) is a non-profit research center specializing in the needs of low-income consumers and the public policies relating to those needs. Analysis of these data is part of continuing research activity funded by the U.S. Department of Energy, Office of Building Technology and State, Local, and Community Programs. The conclusions and opinions expressed may not represent the views of the Department of Energy.

For the full report, go to the website of www.ncaf.org or contact EOS at: eori@earthlink.net

The Winter Energy Outlook for the Poor:

LOW-INCOME CONSUMERS' ENERGY BILLS IN THE WINTER OF 2000-2001

December 20, 2000

by:
Meg Power, Ph.D.
Executive Director
Economic Opportunity Studies
Washington, D.C.

Analysis of these data is part of continuing research activity funded by the U.S. Department of Energy, Office of Building Technology and State, Local, and Community Programs.
The conclusions and opinions expressed may not represent the views of the Department of Energy.

400 NORTH CAPITOL STREET, SUITE G-80, WASHINGTON, D.C. 20001
Tel. (202) 628 4900 *Fax* (202) 393 1831 *E-mail* eori@earthlink.net

The Winter Energy Outlook for the Poor:

LOW-INCOME CONSUMERS' ENERGY BILLS IN THE WINTER OF 2000-2001

This analysis uses updates of the US Department of Energy Residential Energy Consumption Survey data to measure how the high energy prices expected this winter will affect the 27 million low- and moderate-income families eligible for federal Energy Assistance and Weatherization services.[1] It assumes normal weather as defined by the National Oceanic and Atmospheric Administration.[2]

All households face rapidly rising energy costs this year, but low-income energy consumers face true hardship. On December 6, the Department of Energy (DOE) revised its residential fuel cost projections upward for the third time in two months.

Families that have incomes at or below 60% of the median income of their state are eligible for federal Low-Income Home Energy Assistance Payments (LIHEAP) or the US Department of Energy's Weatherization Assistance energy efficiency services. That income ceiling is roughly $21,000 for a family of three, and this report refers to them as 'low-income'; in 2000 about 27 million households fit this definition.[3] Fewer than 15% participated in either federal energy program last year; most states limit such assistance to the households with very low incomes. In fact, the typical family that becomes a LIHEAP recipient has a household income lower than the Poverty guideline, which is now $14,150 for a family of three.[4]

ENERGY MARKET JOLTS: HIGHER PRICES, MUCH HIGHER BILLS

Winter prices for all petroleum products including natural gas are outpacing already pessimistic expectations. Heating oil prices were projected by DOE to remain 65% higher than in 1997, a level 29% above last winter; residential customers' natural gas will cost 40% more than in 1999 per cubic foot.

However, this year's bills will be even higher, as last winter was abnormally warm. For natural gas users DOE expects bills to be more than 50% above last winter; fuel oil users, already hit hard in 2000, can expect bills about 35% higher; users of propane heat can expect bills at least 10% higher; electrically-heated homes will see costs somewhat higher than last year, and 9% higher than in 1997. (This DOE electricity estimate assumes that wholesale price spikes currently seen in West coast markets are not passed through to residential customers.)

For the poor, these figures are catastrophic. Their incomes are not only low, but relatively fixed. Even though many of these families realized some increase in income from 1997 to the present, the cost of energy will wipe out much of the gain in living standard they might have enjoyed .[5] The rate of change compounds the problem. In 1997, the typical eligible low-income consumer spent 14% of all annual income for all household energy bills (a calculation termed 'Energy Burden'), as compared to the 19% expected. Figures 1A and 1B show the speed with which the burden and cost of energy have increased in three years. Figure 1B reflects only the bills for oil and gas heat.

Figure 1A. Changes in Percent of Annual Income Needed to Pay Energy Bills of Low-Income Families

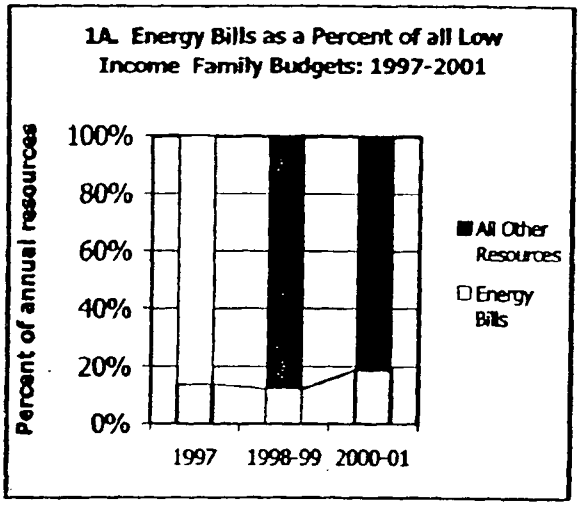


Figure 1B. Changing Winter Bills for Gas Heat and Fuel Oil Heat of Low-Income Families

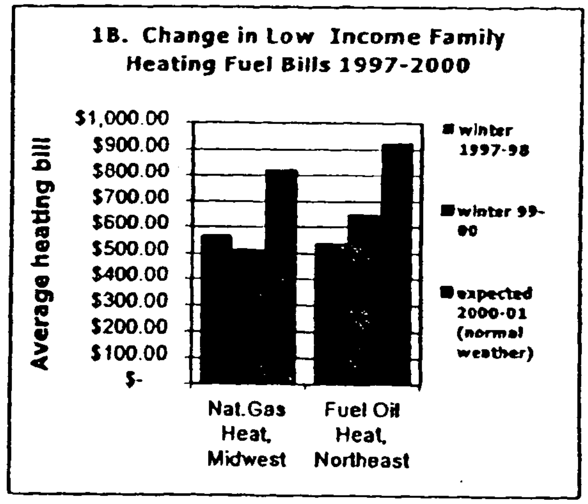


Table A shows the expected national average 12-month energy bills and the energy burdens expected for three groups: the poorest, all the low-income households eligible for Energy Assistance, and the 74 million other consumers not poor enough to qualify for federal programs.

Table A. Expected Average 2000-2001 Household Energy Bills & Energy Burden, by Income Level

Annual Income Level of Households	Est. Oct 00 - Sept 01 Residential Energy Expenditures	Energy Burden (expenditures/income)
At or Less than the Poverty Guideline*	$1,116	22%
Eligible for Energy Assistance**	$1,694	19%
Not Eligible for Assistance	$2,108	5%

* The Poverty Guideline 2000 =$14,150 for a three-person family. ** Eligible = approximately 175% Poverty or less

The national averages above hide substantial variation, and annual estimates hide the sharp impact of the winter bills for the heating fuels most affected. Table B below shows only the winter costs expected for both the heating fuel and the other energy, mainly electricity, for which the poor will have to pay.

Table B. Expected Average 2000-2001 Winter Energy Costs for Low-Income Consumers

Main Heat Fuel of household	No. of Low-Income Households (27m HH)	Avg. Heating Fuel Bill* Oct '00 through Mar '01	Other Energy Bills (lights, appliances, hot water, cooking)	Total Bills: Oct '00 through Mar '01	'Energy Burden:' Winter Energy Bills' share of Winter Income
Fuel Oil	2,700,000	$980	$337	$1,317	29%
Natural Gas	13,800,000	$822	$289	$1,111	27%
Electricity	8,600,000	$598	$113	$711	17%
Propane	540,000	$701	$294	$995	26%
Kerosene/other	1,400,000	$317	$437	$754	16%

*RECs uses a regression model to identify that part of the heat fuel which is used for space heating. All winter uses of the main heat fuel are in the same column. Other electricity and auxiliary fuel usage are in the 'other energy bills' column.

HARD CHOICES AND REAL DANGERS

As the incomes of most low-income families are relatively fixed, they can only be raised by adding work hours. Yet most eligible households already include a worker, unless they are made up of elderly retirees or the disabled. Few have savings or capital to draw upon. The seasonal load of these bills is especially difficult for workers with hourly wage jobs that face post-holiday or weather-related work slowdowns at the coldest season.

Energy Crises: Utility Disconnections, Denial of Service

In 1997, a year with similar temperatures but far lower prices, more than 1.1 million low-income families had their heat shut off for ten days or more in winter because they could not pay.[6] Most states do not have regulations prohibiting utility shutoffs other than during 24 hour periods where the temperatures remain below freezing. This year's bills will create a heavier burden. The poor use only four percent less heating fuel than the rest of the population's average, but their incomes average less than a third of the U.S. median income. Those who depend on delivered fuels are not likely to have extensive credit arrangements, and must usually find cash or be denied deliveries.

THE OUTLOOK THROUGH THE REST OF 2001 FOR LOW-INCOME FAMILIES

While Table B projects costs through this winter, Table C below shows the annual impact of high energy costs if prices remain at comparable levels until Fall 2001. For the period April – September, air conditioning costs for a normal summer have been added to the expected spring and summer bills for the other common household uses. The far right column offers the comparable Energy Burden to be expected by the average consumer with income too high to qualify for assistance. Clearly, the impact of energy market changes differs dramatically among income groups.

Table C. Expected Year-long Energy Costs and Energy Burdens for Low-Income Consumers and All Other Households, 2000 - 2001

Main Heat Fuel of household is:	Avg. Total Energy Bills: Oct '00 through Sep '01	12-month Avg. Energy Burden (percent of income spent on Energy)	12- month Avg. Energy Burden: Non-Eligible HH
Fuel Oil	$2,306	26%	6%
Natural Gas	$1,951	22%	4%
Electricity	$1,496	11%	3%
Propane	$2,450	24%	7%
Kerosene & other	$1,509	16%	5%

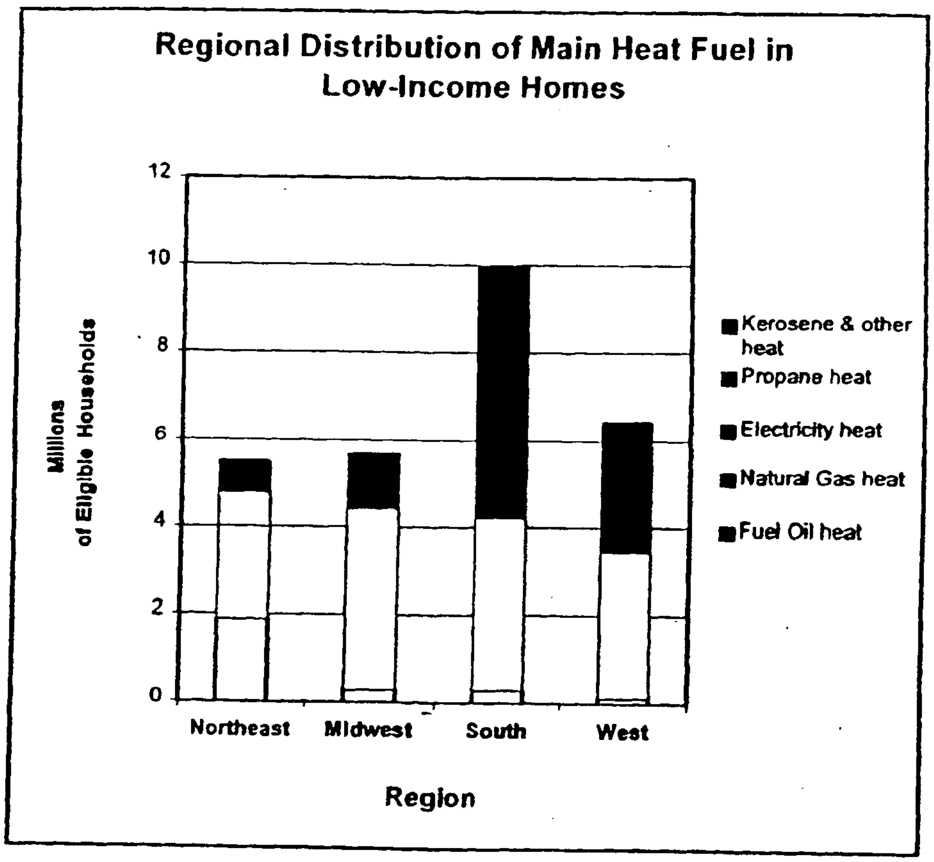
While the low-income families heating with fuel oil or gas can expect to spend about a quarter of their entire annual income on energy bills, by contrast, the group that is not eligible for assistance will spend about five

Table E. Winter 1999-2000 and Winter 2000-2001: Expected Heat Fuel Bills for Low- and Moderate-Income Households in the Northeast and Midwest:

Main Heat and Region	1999-00	2000-01 (with normal weather)	% One-year Increase
Nat.Gas Heat, Midwest	$ 517	$ 822	59%
Fuel Oil Heat, Northeast	$ 649	$ 926	43%

Figure 2 shows the low-income population distribution among regions and within the regions by the heating fuels used in their homes. Clearly, all regions have significant natural gas usage, while the Midwest is the most gas-dependent. The markets for electricity affect all consumers, but the major winter electric heating load is in the South and West.

Figure 2. Regional Distribution of Fuels



PROGRAMS: ENERGY CONSERVATION, PAYMENT SUPPORT

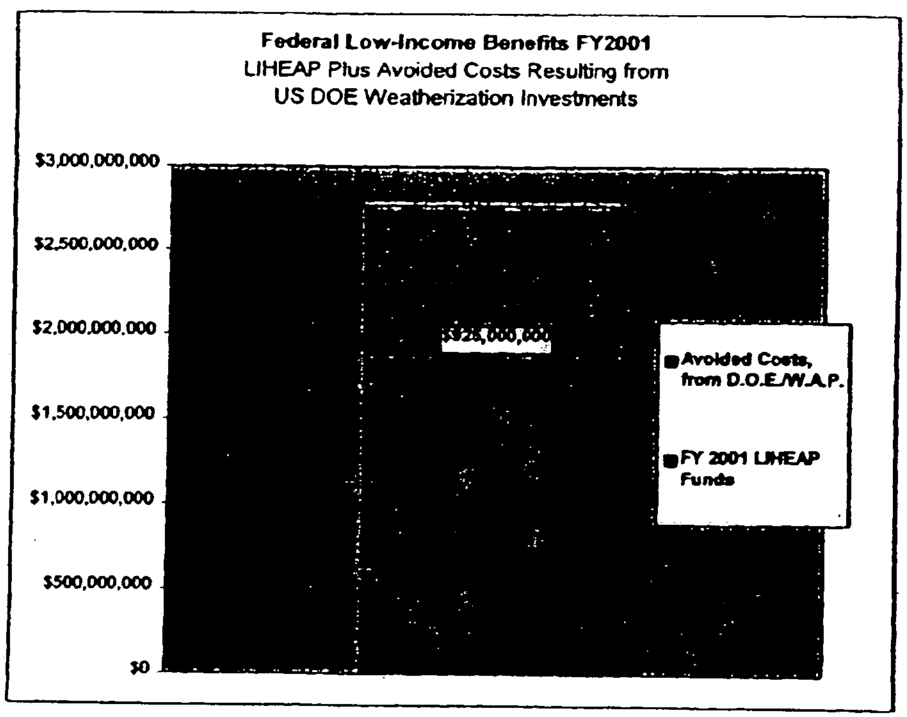
The programs available fall far short of the needs ahead this winter.

- Weatherization:

The Department of Energy Weatherization Assistance Program has efficiency investment resources that have to date been extended to fewer than 20% of all eligible units. It focuses on homes with high potential to save energy and with especially vulnerable families; at the prices projected, a typical 'weatherized' consumer will spend about $285 less on natural gas this winter than would have been the case before the house was weatherized. The comparable figure for the weatherized oil-heated home will be nearly the same, $280.[8] That modest figure means a good deal more to those with tight budgets, as it represents a savings of 1.5% - 2% of all their resources. The Weatherization program had planned to improve an additional 200,000 low-income homes by FY 2001, but budget cuts in FY 1995 and subsequent years now mean that about $56 million will be billed to families this year that could have been avoided if the original program had been maintained.

Figure 3 shows the contribution of Weatherization investments already in place in low-income housing. This winter the avoided costs to five million consumers will be nearly $1 billion, or 50% of the projected LIHEAP expenditures in 2001.

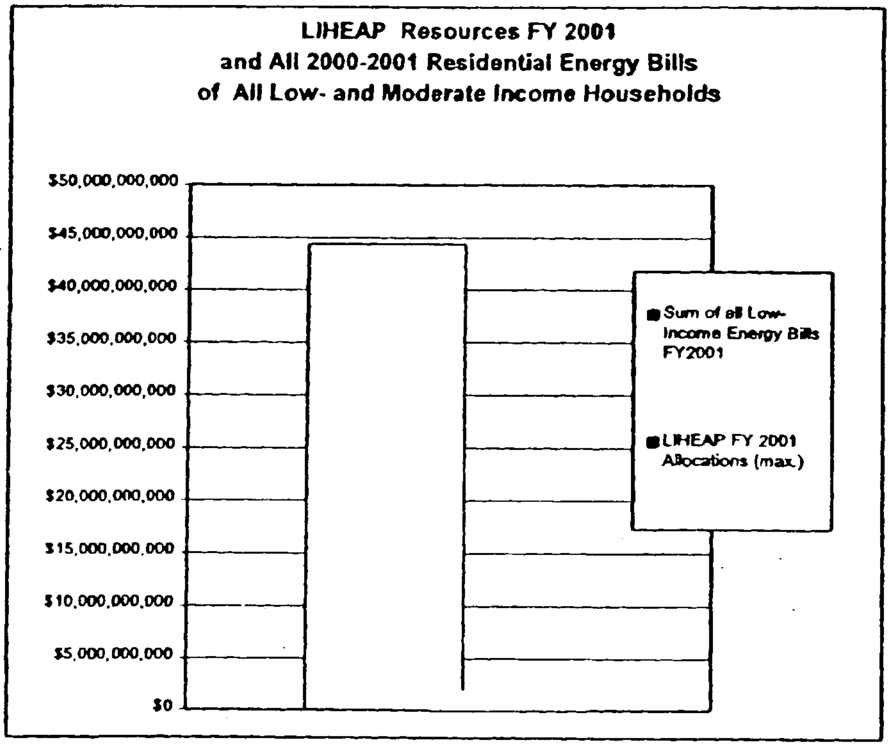
Figure 3.



Energy Assistance:

Figure 4 shows the relationship between the bills the eligible population will receive in the next few months and the LIHEAP funds available.

Figure 4.



Clearly many of the poor cannot meet their needs by relying on their own resources in combination with the available funding. At no time in the past half century have energy market shocks affected so many residential consumers so profoundly. The aggregate effect, if projections are correct, will transfer significant wealth to the energy sector. At this date, nearly Christmas 2000, community-level contingency plans for avoiding potential family economic hardships do not seem to be in place.

ENDNOTES

[1] This national database is compiled every four years by the DOE, based on household surveys on home energy use. These comprehensive data provide details on consumption for all income levels. The report is available through the Energy Information Administration at the department; http:///www.doe/eia.gov The responses of the low-income households eligible for energy assistance in 1997 has been updated by Economic Opportunity Studies, with support from the Office of Building Technology, State and Community programs. It reflects current DOE fuel price predictions and normal weather. Economic Opportunity Studies is a non-profit research group specializing in energy issues that affect the poor. These findings do not necessarily represent the views of the Department of Energy.

[2] USDHHS, Office of Energy Assistance, Washington, DC. Interview November 6, 2000.

[3] USDHHS, Office of Community Services, Washington, DC. *LIHEAP Information Memorandum,* March 2000.

[4] U.S. Bureau of the Census, Poverty in the United States, 1999, Washington, DC, March 2000 and *Annual Demographic Survey March 2000 Supplement.*

[5] U.S. Bureau of the Census, Money Income in the U.S., 1999, shows income by income 'quintile.' The lowest quintile includes most eligible households. They experienced a little under 9 percent income growth on average.

[5] Economic Opportunity Studies for Association of Energy Affordability, *A Profile of the Energy Usage and Needs of Low-Income Americans,* NY, 1999, p. 42.

[7] ibid., p. 10.

[8] Oak Ridge National Laboratory, 2000.

CERA®

Decision Brief

NORTH AMERICAN
ELECTRIC POWER

APRIL 1999

MIDWEST WHOLESALE POWER MARKETS: READY FOR A REPEAT?

by Lawrence J. Makovich and Joseph Sannicandro

The Midwest power markets are preparing for a replay of last year's price spikes. Demand and supply balances ~~this~~ summer should be even tighter than they were last summer when spot energy prices broke from their normal $12 to $30 per megawatt hour (MWh) range to reach hourly highs of over $7,000 per MWh and weekly on-peak average prices of over $600 per MWh. The magnitude of hourly prices this summer is uncertain, but it is a good bet that weekly average on-peak prices will reach several hundred ~~dollars~~ per MWh. The continued strength of the economy and normal weather should push increases in demand beyond the scheduled increases in supply.

What is different, of course, is that the market participants learned from the experiences of last summer. Buyers learned that a sellers' market can arise very quickly, and also realized the value of locking up supply rather than facing the possibility of having to search for supply when few options are available. As a result, buyers have turned to short-term futures contracts to buy ahead and provide an insurance policy against the financial implications of a price spike. Thus, the market clearing price for Midwest electric futures is the fulcrum for market expectations.

Market Expectations

In the Autumn 1998 CERA *North American Electric Power Watch,* CERA predicted that prices for on-peak electric futures in the Midwest market would strengthen substantially from the $70 per MWh level as the summer season neared and evidence accumulated that the economy would continue to grow. On-peak futures for the months of July and August in the Cinergy market have recently been trading as high as $135 per MWh (see Figure 1).

Owning $135 per MWh power in the Midwest last summer would have provided profits in only three out of thirteen weeks (see Table 1). However, the gains during the three weeks in June and July when average on-peak spot electric prices exceeded $400 would have more than offset the losses incurred during the remaining ten weeks of the summer, when prices cleared between $28 and $72 per MWh. In CERA's view, current futures prices reflect the expectation that gains are possible again this summer if there are two to three weeks of prices in the $300 to $400 per MWh range. Therefore, market expectations are for a repeat of last year's price spikes.

CERA is pleased to announce the release of a new Multiclient Study, *At the Crossroads of Competition: The Future of the Midwest Gas and Power Markets.* This authoritative study provides detailed regional analysis of basis differentials, gas and power supply outlooks, forward price curves, and alternative views of the future, including implications for key segments.

For more information on this CERA Multiclient Study, please contact Mark Silver by telephone: (617) 498-9125 or e-mail: msilver@cera.com.

Please mark your calendars for CERA's Spring 1999 North American Electric Power Executive Roundtables:

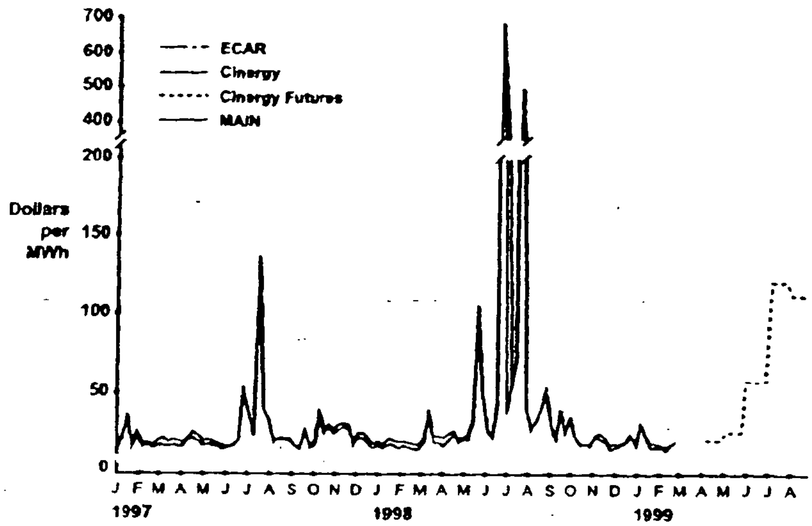
New York (Global Energy Overview)	May 7
Calgary	May 12
San Francisco	May 14
Houston	May 20
Charlotte, NC	June 8
Boston	June 21

To register please contact CERA Registration by telephone: (617) 497-6446, extension 800; fax: (617) 498-9176; or e-mail: register@cera.com.

Cambridge Energy Research Associates

Figure 1

Midwest Weekly Average On-peak Spot Electric Prices



Source: Cambridge Energy Research Associates.

The Price Spike Dynamic

Price spikes—the deviation of market-clearing prices from short-run marginal costs—are not the typical outcome in competitive wholesale power markets. The interaction of rival buyers and sellers in wholesale power markets typically pushes the market-clearing price toward the short-run marginal cost of production. As a result, an ordering of the incremental costs of generating resources provides an approximation of the market supply curve. Figure 2 displays the electric supply curve for the US Midwest (comprising the East Central Area Reliability Coordination Agreement [ECAR] and Mid-America Interconnected Network [MAIN] regions of the North American Electric Reliability Council). The bulk of the supply curve in this market comprises coal and nuclear units. The short-run marginal operating costs of these technologies is typically around $20 to $25 per MWh. The supply curve shifts abruptly as it moves from these technologies into higher cost, less efficient oil- and gas-fired peaking units.

During the majority of the year the demand curve intersects the supply curve on the flat portion of the curve, and market-clearing prices average $20 to $25 per MWh. However, during peak demand periods, the demand curve intersects the supply curve in the "elbow" area, where the short-run marginal cost is determined by higher cost, less efficient oil- and gas-fired peaking units. Thus bidding between rival oil and natural gas–fired simple-cycle peaking units can quickly move market-clearing prices into a range of $50 to $75 per MWh.

767

DOE002-0777

Table 1

Weekly On-peak Spot Electric Prices, Summer 1998
(Dollars per MWh)

	ECAR	Cinergy	MAIN
June 5	26.83	26.83	26.73
June 12	23.01	23.01	22.36
June 19	48.67	48.67	41.24
June 26	655.99	656.04	690.36
July 3	418.39	418.39	37.83
July 10	53.28	53.28	54.33
July 17	71.75	71.75	71.92
July 24	498.41	498.41	409.28
July 31	40.35	40.35	39.07
August 7	27.76	27.76	26.96
August 14	33.26	33.25	32.74
August 21	40.58	40.61	41.53
August 28	55.13	54.97	51.72
June Average	188.63	188.64	195.17
July Average	216.44	216.44	122.49
August Average	39.18	39.15	38.24
Summer Average	**189.49**	**189.48**	**145.57**

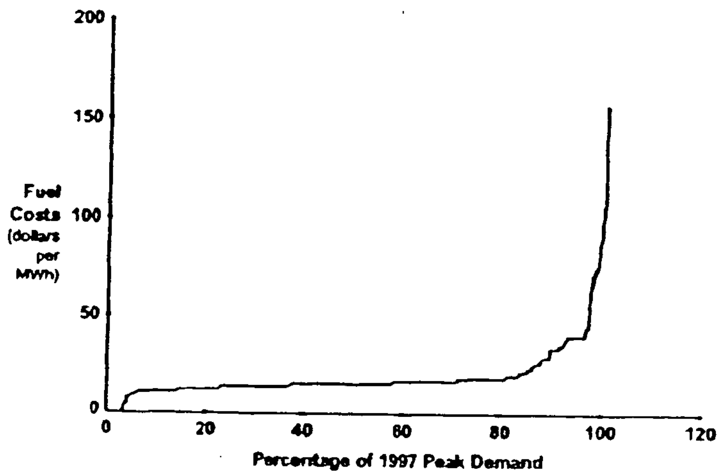
Source: Cambridge Energy Research Associates.

During the last week of June 1998, the demand for power came very close to outstripping supply. As a result, demand intersected supply close to the end of the supply curve, and the number of rival suppliers diminished. As the number of suppliers declined, a sellers' market arose, and bidding strategies shifted to bids based on what the market would bear. This shift in bidding strategies caused prices to move up to several thousand dollars per MWh. Prices returned to lower levels when demand eased, rivalry returned, and competitive forces shifted bid strategies back to incremental cost-based bids.

Several events combined last summer to create the conditions that supported this price spike dynamic. A combination of extended nuclear outages, a number of large fossil units tripping offline, abnormally hot weather, the default of several power marketers, and storm-related damage to generation and transmission facilities combined to tighten demand and supply conditions. Although this sequence of events is unlikely to occur again, the supply and demand fundamentals of the Midwest indicate that a similar tightening of demand and supply is probable, and thus prices are likely to spike again this summer.

Figure 2

Midwest Supply Curve



Source: Cambridge Energy Research Associates.

Supply and Demand Fundamentals

Preliminary estimates of 1998 peak demands show an increase of approximately 4,000 megawatts (MW) in the ECAR and MAIN regions from 1997 peaks. These peaks occurred during a summer season that was 13 percent hotter than normal. For 1999 CERA expects peak demand to increase to 5,100 MW in the Midwest, as continued economic growth and the return of General Motors facilities from their strike will offset the negative effect of a return to normal summer weather.

The supply response to the price spikes comes from a number of areas, including new greenfield capacity, uprating of existing capacity, and improved nuclear availability. Last summer's price spikes triggered plans to add over 10,000 MW of new greenfield capacity to the Midwest market. However, the lead times associated with siting and constructing these projects mean that less than 1,400 MW of new greenfield capacity will be added for the summer of 1999. CERA expects improved nuclear availability this summer, providing a total of approximately 1,900 MW of supply. In addition, the uprating of existing capacity has provided approximately 300 MW per year over the past two years in the Midwest. CERA expects roughly 500 MW of additional supply from this capacity creep in 1999, for a total addition to supply of 3,800 MW.

The price spikes also triggered a retreat from interruptible power services. Approximately 5,700 MW of demand-side management and interruptible contracts were available in the Midwest last summer. Many interruptible customers avoided interruptions by buying through at market prices last summer and have responded to the events of 1998 by switching back to firm supply contracts. Although some new interruptible customers are present, CERA expects the amount of interruptible supply to decrease from last summer. In addition, the explosion at the River Rouge industrial facility near Detroit has removed 550 MW of supply from the system.

Table 2

Midwest Supply and Demand Balance

Demand	Gigawatts
1998 Peak	140.1
1999 Load growth	5.1
1999 Peak	**145.2**
Supply	
1998 Capacity	149.9
1999 Supply response	
New capacity	1.4
Estimated capacity creep	0.5
Improved nuclear availability	1.9
River Rouge	(0.6)
Total	*3.3*
1999 Capacity	**153.1**
1998 Capacity margin (percent)	6.5
1999 Capacity margin (percent)	5.2

Source: Cambridge Energy Research Associates.
Note: Totals may not add because of rounding.

The net increase in supply does not appear to match the expected increase in peak demand (see Table 2). An expected net increase of 3,250 MW of supply results in the capacity margin for the combined ECAR/MAIN Midwest region declining from 6 percent in 1998 to 5 percent in 1999. The demand and supply balance looks tight enough to trigger price spikes again that could move weekly average on-peak prices to the several hundred dollars per MWh level.

Dampening the Boom

Although CERA believes there is a high probability of a repeat of the 1998 price spikes, they are not guaranteed. Weaker-than-expected electric demand would remove the stress from the supply system, preventing sellers' market conditions from arising. Two factors could dampen electricity demand. The first is a slowdown in the national economy. A decrease in real GDP would likely cause a flat or decreasing peak demand rather than the expected increase. At this point, however, there are few signs of this happening. The second factor is the weather. A mild summer could also result in weak or negative peak demand growth.

If either—or both—of these events were to occur this summer, prices could instead move into the $50 to $75 per MWh range, and weekly averages for July/August could remain in the $35 to $45 per MWh range.

LAWRENCE J. MAKOVICH, CERA Director, is Research Director of CERA's North American Electric Power Service. He is an expert on the US electric power industry, including utility economics, regulation, and strategy. Dr. Makovich advises clients on the changing dynamics of the North American power business. He has addressed numerous industry conferences and is the author of several reports and articles on the future of the electric power business. Prior to joining CERA, he was Senior Electricity Economist at DRI/McGraw-Hill. He is the author of several articles and reports on the future of electric power. He is the author of the CERA reports *"Cost" vs. "Worth": Revaluing Generating Assets in a Competitive Market* and *Reality Check: US Electricity Demand at the End of a Rebound*, among others; a contributor to CERA's *Electric Power Watch*; and advises clients on utility market fundamentals, demand trends, and regional price scenarios and strategies.

JOSEPH SANNICANDRO, CERA Director, North American Electric Power, is an expert in economic modelling and energy forecasting, including electricity demand, generating capacity requirements, electricity prices, fuel demand, and end-use data. Before joining CERA, Mr. Sannicandro managed load data collection and forecasting projects for TASC, Inc. Previously, he was a Senior Economist at DRI/McGraw-Hill. Mr. Sannicandro is the author of the CERA Decision Brief *Power Marketing Activity: A Heavy Foot on the Accelerator*, a coauthor of the CERA Private Report *Power Marketing: The Birth of a New Industry* and of the CERA Decision Brief *Spot Market Pricing of Electricity: Towards the New Market*, and a regular contributor to CERA's *North American Electric Power Watch*.

221 I

THE WILDERNESS SOCIETY

STATEMENT OF DAVID ALBERSWERTH

ON BEHALF OF

THE WILDERNESS SOCIETY

BEFORE THE

HOUSE RESOURCES COMMITTEE

SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

REGARDING

"DOMESTIC NATURAL GAS SUPPPLY AND DEMAND:

THE CONTRIBUTION OF PUBLIC LANDS & THE OCS"

MARCH 15, 2001

772

Madame Chairman and Members of the Subcommittee, thank you for the opportunity to testify on behalf of The Wilderness Society and its 180,000 members on the important matter of the contribution of public lands to domestic natural gas supplies. My name is David Alberswerth, and I am the Director of The Wilderness Society's Bureau of Land Management Program. Prior to joining The Wilderness Society staff last year I served the Clinton Administration within the Department of the Interior as Special Assistant and Senior Advisor to the Assistant Secretary for Land and Minerals Management, and Deputy Director of the Office of Congressional and Legislative Affairs.

It is The Wilderness Society's hope that in exercising its oversight role regarding this important matter, the subcommittee will seek to be as objective as possible in reviewing the extent of natural gas resources on our public lands, and the environmental values that also reside on those lands that can be placed at risk by natural gas exploration and development activities. For although natural gas extracted from our public lands is an important component of our nation's well-being, the environmental, wildlife, watershed, and wilderness values of those lands are also vitally important to Americans.

Some suggest that these two interests are incompatible, or that we cannot meet our energy needs without sacrificing some of our most precious lands. The Wilderness Society believes that we can meet our energy needs without sacrificing our most treasured national landscapes. In fact, America has a proud tradition of combining a strong economy with strong environmental values, and we urge the subcommittee to be guided by both goals. A review of some pertinent facts, which I will set forth below, demonstrates clearly that this is possible.

One fact of central importance that I wish to draw to the subcommittee's attention is that the vast majority of public lands managed by the Bureau of Land Management (BLM) in the Overthrust Belt states of Colorado, Montana, New Mexico, Utah and Wyoming are presently open to leasing, exploration and development by the oil and gas industry. In fact, information presented to the Assistant Secretary for Land and Minerals Management by the BLM in 1995 indicated that over ninety-five percent of BLM lands in those states (including "split estate" lands) were available for oil and gas leasing. I have appended to this testimony the BLM's synopsis of the availability of BLM lands in those states for oil and gas leasing, exploration and development (see attachment I). Though there have been some changes in the land status of some of the lands indicated on the attachment since this information was prepared by the BLM in 1995, the data here is still essentially valid. I suggest that it would be in the subcommittee's interest to request an update of this information from the BLM for the subcommittee's consideration at next week's hearing on the same topic.

It is also relevant to any discussion of our public land energy policies to understand that the BLM has been carrying out a robust onshore oil and leasing program for the past decade. For example, the Clinton Administration issued oil and gas leases on more than 26.4 million acres of public lands during the last eight years (see attachment II). According to the BLM publication, *Public Rewards from Public Lands*, there are nearly 50,000 producing oil and gas wells on the public lands (see attachment III). Thousands of new drilling permits have been issued during the past eight years - 3,400 by the BLM in FY 2000 alone (see attachment IV). In fact, production of natural gas from onshore and offshore federal lands has steadily increased from 1981 to the present (see attachment V).

Criticism by some that in recent years too much public land has been made unavailable for oil and gas activities is simply not supported by the facts. Upon close examination, industry criticism of "lack of access" to onshore public lands really falls into two categories: lands that are off-limits entirely to oil and gas development; and lands available for development if the industry takes special care of the environment. The former areas include wilderness areas, wilderness study areas, and/or areas such as steep slopes, karst areas, and areas where other mineral activities are taking place, in other words, places where oil and gas activities could pose extreme environmental or safety hazards, or be incompatible with other values. Currently, such areas comprise roughly 5 percent of BLM-managed lands in the five states.

The latter category often encompasses areas where evidence indicates the presence of sensitive wildlife habitats, such as elk calving areas, or sage grouse leks, where operations at certain times of the year could pose severe threats to wildlife. In such cases, the BLM may require that operations only occur at certain times of the year, when such areas are not in use by certain wildlife species. In some cases, the BLM imposes "No Surface Occupancy" leases, whereby the lessee is required to access the oil and gas resource from off-site. Such "NSO" stipulations are also designed to protect wildlife habitats, while making the resource available for extraction. The types of special imposed to protect environmental values can be summarized as follows:

"Standard Stipulations" -- These are provisions within standard BLM oil and gas leases regarding the conduct of operations or conditions of approval given at the permitting stage, such as: prohibitions against surface occupancy within 500 feet of surface water and or riparian areas; on slopes exceeding 25 percent gradient; construction when soil is saturated, or within 1/4 mile of an occupied dwelling. These are generally applied to all BLM oil and gas leases, regardless of special circumstances.

"Seasonal" or other "Special" Stipulations -- "Seasonal Stipulations" prohibit mineral exploration and/or development activities for specific periods of time, for example sage grouse strutting areas when being used, hawk nesting areas, or on calving habitat for wild ungulate species. These are often imposed at the request of state wildlife officials, as well as in compliance with U.S. Fish and Wildlife Service requests to protect sensitive species.

"No Surface Occupancy" -- NSO leases prohibit operations directly on the surface overlaying a leased federal tract. This is usually done to protect some other resource that may be in conflict with surface oil and gas operations, for example, underground mining operations, archeological sites, caves, steep slopes, campsites, or important wildlife habitat. These leases may be accessed from another location via directional drilling.

The imposition of special, seasonal, or NSO stipulations are an attempt by the BLM to balance the industry's desire for access to oil and gas deposits, with the BLM's responsibility to manage other resources on the public lands. Although industry public relations campaigns frequently emphasize the benign nature of contemporary exploration and development technologies, when required by the BLM to utilize these technologies to minimize environmental impacts, the industry is reluctant to do so. However, the purpose of most of these stipulations, about which the industry now appears to complain, is simply to ensure that these advanced technologies are used to minimize environmental impacts of energy production on environmentally sensitive public lands. These stipulations do not reduce our nation's access to its energy resources.

With respect to the national forests, the national forests currently supply 0.4% of total US oil and gas production, half of which occurs on the Little Missouri Grasslands (*Forest Service Roadless Area Conservation FEIS, 2000*, pages 3-312 and 3-316). The remaining national forest land account for less than 0.2% of total production in 1999 (Ibid.). The vast majority of roadless areas on the national forests subject to the new Forest Service roadless protection policy have been open to leasing for decades, and there has been little interest in exploiting potential resources, even though the real price of oil in the past was much higher than it is today.

I would like to turn now to estimates of natural gas resources and their relationship to the public lands. A 1999 report published by the National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*, indicates that there is a "natural gas resource base" in the lower 48 states of 1,466 trillion cubic feet of gas (TCF) (pp.7-8, *Summary Report*). (The figure does not include estimated gas resources in Alaska, estimated at Prudhoe Bay to be in the neighborhood of 25 TCF.) The report also estimates that, although current yearly consumption is approximately 22 TCF, that figure will increase to 31 TCF by 2015 (p.5).

In addition, the NPC report estimates that approximately 105 TCF of this estimated gas resource base is entirely off-limits to development, including 29 TCF from federal lands in the Rocky Mountain states, and 76 TCF from OCS areas off the Atlantic coast, the eastern Gulf of Mexico, and the Pacific coast (p.13). If we add to that figure the 9.4 TCF estimated by the Advanced Resources International analysis of the Forest Service's new roadless policy to be unavailable,[1] we have approximately 115 TCF of the 1,466 TCF lower-48 gas resource base off-limits to extraction. The *Summary Report* also indicates that 108 TCF in the Rocky Mountain states "are available with restrictions." These lands in fact are available for development under the stipulations outlined above, so should not be counted as unavailable for development.

If we eliminate the 115 TCF from the NPC's estimated "natural gas resource base" of 1,466 TCF, we are left with 1,351 TCF available for future extraction. At a 31 TCF per year consumption rate, that is enough gas to meet America's anticipated needs for approximately 40 years. Given this, it is difficult to understand the urgency with which the industry is pressing its case that it needs to invade some of America's most beautiful and environmentally sensitive landscapes, or reduce the environmental protection afforded wildlife and other values on the public lands, in order to meet anticipated future demands for natural gas.

In conclusion, if we are careful, we can pursue energy policies that allow and even encourage increased natural gas use, while protecting sensitive public lands and the environmental values that all Americans have a right to have protected. But our policies must also recognize that there are adverse impacts to natural gas development, and valid safety concerns with natural gas distribution issues, that should not be swept under the carpet in a headlong drilling and development frenzy.

[1] "...with implementation of the proposed roadless areas, about 9.4 Tcf of gas beyond that determined as no 'access' in the 1999 NPC study would be impacted as 'standard lease terms' and "access restrictions" resources move into the 'no access' category." *Undiscovered Natural Gas and Petroleum Resources Beneath Inventoried Roadless and Special Designated Areas on Forest Service Lands analysis and Results*, Advanced Resources International, Inc., November 20, 2000, p. 3.

Availability of Public Lands

The vast majority of public lands are available for leasing. In the states with considerable production of 116.6 million acres only 2.9 million acres are not open for leasing. In Colorado 16.2 million acres are open and 600,000 closed to leasing; in Montana out of 19 million acres 400,000 are closed; in New Mexico of 29.9 million acres of lands only 1.3 million is not open to leasing; in Utah 900,000 acres are closed to leasing leaving 21.2 million acres open; in Wyoming 700,000 acres are closed out of 28.6 million.

State	Total Acres (Millions)	Acres Open to Leasing	Acres Closed to Leasing
Colorado	16.8	16.2	0.6
Montana	19.0	18.6	0.4
New Mexico	29.9	28.6	1.3
Utah	22.1	21.2	0.9
Wyoming	28.6	27.9	0.7
Total	116.4	112.5	3.9
Percent		96.6	3.4

NEI

NUCLEAR ENERGY INSTITUTE

222

John Kane
VICE PRESIDENT
GOVERNMENTAL AFFAIRS

March 14, 2001

The Honorable Sherwood Boehlert
Chairman
Science Committee
United States House of Representatives
Washington, DC 20510

Dear Mr. Chairman:

In testimony before your committee on February 28, Ms. Mary Hutzler of the Energy Information Administration (EIA) reviewed the projections from the *Annual Energy Outlook 2001* published in December 2000. The nuclear industry would like to call to your attention assertions in the testimony that do not represent an accurate assessment of the current status of nuclear energy or the future prospects for this emission-free source of electricity.

In its testimony (page six), the EIA projects that production of electricity from natural gas and coal will increase through 2020 to meet growing demand for electricity and to offset the decline in nuclear power due to retirement of existing nuclear power plants. EIA assumes that continued operation of these nuclear plants would not be economical compared to the cost of new generating facilities.

The Nuclear Energy Institute takes great exception to this conclusion as it leads your committee, and the general public, to believe that nuclear power is being phased out in this country because it is not cost-competitive. Nothing could be further from the truth.

U.S. nuclear power plants are well positioned for a competitive electricity market. The cost of operations, maintenance and fuel has been declining for more than a decade. U.S. nuclear power plants are immune to the volatility in fossil fuel prices that has caused the dramatic increase in electricity prices in many parts of the nation. And nuclear power plants are not affected by the escalating clean air compliance requirements that will increase the cost of electricity from coal-fired and gas-fired generating plants in the years ahead.

1776 I STREET, NW SUITE 400 WASHINGTON, DC 20006-3708 PHONE 202.739.8060 FAX 202.785.4019 www.nei.org

This explains why five nuclear units have already renewed their operating licenses to run for 20 years beyond their initial 40-year license. Five other units have formally notified the Nuclear Regulatory Commission (NRC) that they intend to renew their licenses, and we expect that nearly all 103 U.S. nuclear units will extend their licenses because operating these plants for an additional 20 years represents the lowest-cost, most reliable source of electricity available from any source.

The steady reduction in the cost of nuclear electricity during the 1990s is partly explained by the significant increase in the plants' safety and reliability, and in the amount of electricity they produce. In 2000, U.S. nuclear plants produced approximately 755 billion kilowatt-hours (the second record year in a row), and operated at an average capacity factor of 89.6 percent. The increase in output from existing nuclear plants satisfied approximately 30 percent of the increase in electricity demand during the 1990s. Improved economic performance, output and reliability have been accompanied by a similarly dramatic improvement in safety performance, measured by the quantitative performance indicators monitored by the industry and the NRC.

On average, a U.S. nuclear power plant produces electricity for less than 2.5 cents per kilowatt-hour and, in many cases, closer to 2.0 cents per kilowatt-hour. This includes *all* costs such as fuel, operations, maintenance, ongoing capital requirements, funds set-aside for decommissioning the plant at the end of its useful life, and the one-mill-per-kilowatt-hour fee for used fuel management paid to the federal government. This is the so-called "going forward" cost, which does not include recovery of the original capital investment, but is the sole determinant of whether or not the unit will be dispatched. The 2.0-cent electricity from the average nuclear unit is significantly lower than the cost of electricity from new gas-fired combined cycle power plants. At today's gas prices ($4-5 per million Btu), NEI's analysis indicates that a new gas-fired plant will produce electricity for between 4.5 cents and 5.2 cents per kilowatt-hour. Given that gas-fired electricity is twice as costly as nuclear electricity, no rational economic model would shut down a nuclear unit and replace it with gas-fired capacity, as the EIA's forecasts suggest.

Given the credibility attached to the Energy Information Administration's forecasts for nuclear energy in the United States, NEI believes it is important that these forecasts be correct, with a sound factual and analytical basis. NEI has analyzed the basis for the agency's forecasts in order to understand the assumptions and methodology behind them. We completed a detailed assessment of the 1999 edition of the *Annual Energy Outlook*, for example, and discovered a number of mistakes, suspect assumptions, and the use of cost and performance data that were several years out of date. Although we have briefed EIA staff on our findings, we suspect that the results in the latest *Annual Energy Outlook 2001* reflect similar mistakes in fact and judgment. We believe, at a minimum, that EIA's forecasting assumptions and methodologies should be subjected to rigorous peer review before publication, given the importance attached by many to EIA's forecasts.

The nuclear industry also believes that EIA's assessment of future nuclear power plants does not reflect current business realities. The nuclear industry has an aggressive program underway to define and put in place the business conditions necessary for new nuclear energy facilities. The need for new nuclear power plants is significantly more pressing than many realize, given the current volatility in oil and gas markets, larger-than-forecasted increases in electricity demand, and the cost impact of new clean air requirements already promulgated but not yet fully implemented.

We believe that new nuclear plants can be cost-competitive even sooner if some of the barriers to market penetration are removed. For example, nuclear energy is an emissions avoidance technology. Under current law, technologies that avoid emissions such as hydro and nuclear are selectively excluded from federal and state clean air compliance programs

In summary, NEI believes that the contribution from nuclear energy to U.S. electricity supply will increase in the years ahead because:

1. Most of the existing nuclear units will continue to operate through the end of their initial 40-year license terms and through 20-year license extension periods.
2. Output from the existing plants will continue to improve in the near-term because of continuing gains in efficiency and reliability.
3. New nuclear power plants will be built starting in the latter half of this decade, with a significant number of new nuclear units in service by 2020.

We believe the EIA's methodology and assumptions do not take into consideration these positive factors when assuming retirements of nuclear generating facilities and the possibility of new generation. We urge you to take another look at nuclear energy and, to that end, request the opportunity to testify on behalf of the industry at a hearing before your Committee at your earliest convenience.

Sincerely,

John Kane

Attachments

cc: The Honorable Ralph Hall
The Honorable Roscoe Bartlett
The Honorable Lynn Woolsey
The Honorable Vern Ehlers
The Honorable Joe Barton
The Honorable Rick Boucher
Mary Hutzler, EIA
Bill Magwood, DOE
Kevin Kolevar, DOE

Testimony of

James T. Hackett
Chairman, President and CEO
Ocean Energy, Inc.

on behalf of the
Domestic Petroleum Council

before the
House Resources
Subcommittee on
Energy and Mineral Resources

March 15, 2001

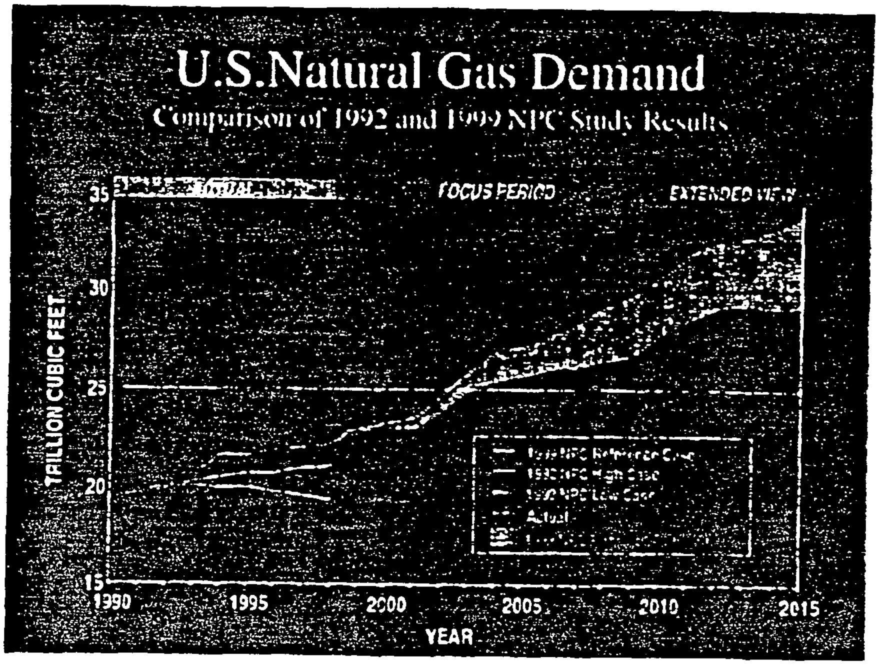
Good afternoon. I'm James T. Hackett, Chairman, President and CEO of Ocean Energy, Inc.

Ocean Energy is a Houston-based independent oil and gas exploration and production company with a market capitalization of $4.5 billion dollars. Two thirds of its reserves and production are in the United States. It has a large commitment to growing our natural resource base as it spends nearly $1 billion dollars in 2001 on exploration and development, especially deepwater drilling in the Gulf of Mexico. Drilling in these water depths(of up to two miles deep) costs from $20 to $100 million dollars per well.

On behalf of the twenty-two large U.S. independent natural gas and oil exploration and production companies of the Domestic Petroleum Council, thank you for inviting us to be here today to discuss the importance of access to federal government lands if we, as a nation, are to have the future natural gas supplies that will power the new internet economy and fuel our industry, and keep our homes and businesses warm in the winter and cool in the summer.

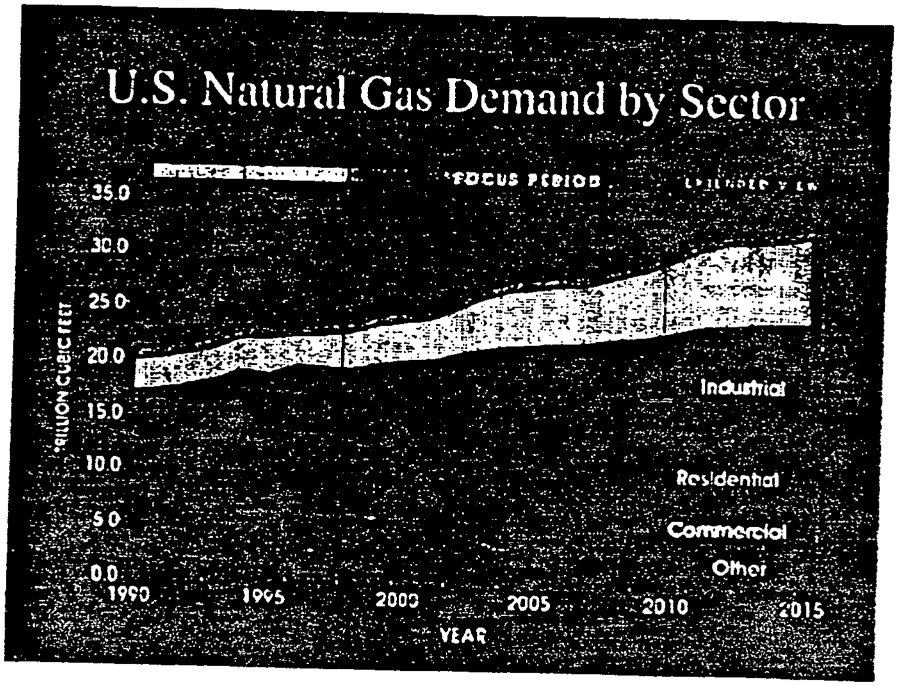
The DPC companies are all very concerned about this issue. We produce one-fifth or more of the nation's natural gas. We are responsible for most of the wells that U.S. independents drill. We know as well as anyone the challenge we face in having access to the gas resources we'll need to find and produce in the future.

I'll cite examples of that challenge, and some policy and implementation changes that will help us meet it.



First, let's remember that we are facing a U.S. natural gas demand increase of more than 30% by the year 2010, according to the 1999 natural gas study of the National Petroleum Council that was requested by the U.S. Department of Energy.

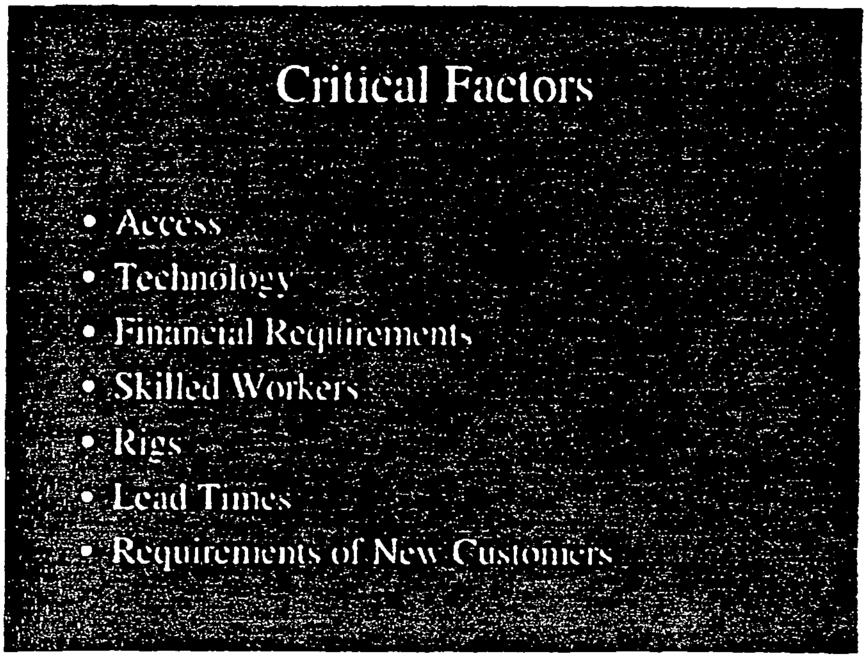
The last study of this type was conducted in 1992 and, as is shown here, the growth in demand for this clean-burning fuel was underestimated. It is still early to predict, but it is very possible that once again demand projections are conservative. There are recent indications that natural gas demand could be even stronger than the latest NPC projections.



Of the annual 7 trillion cubic feet (TCF) increase in natural gas demand projected by 2010, almost half will be required for power generation.

Over 90% of projected new electrical generating capacity will be gas fired.

It is estimated that about 85,000 megawatts (MW) of new gas fired generating capacity will come on line in the US this year alone, resulting in increased gross gas usage of almost 650 BCF per year.



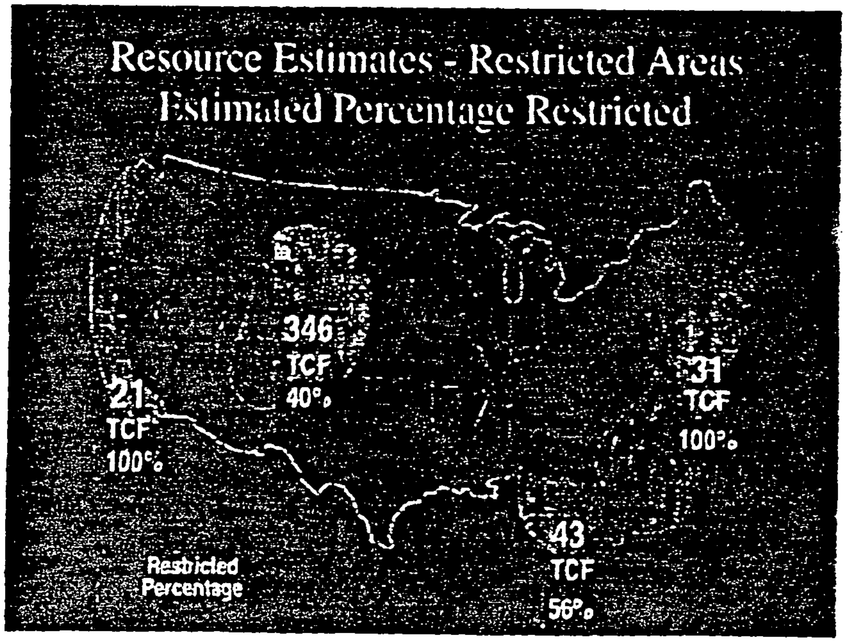
The NPC Study concluded that the North American natural gas resource base is sufficient to meet the projected demand for natural gas. However, this ability is very dependent on industry and government positively addressing seven key challenges.

Access topped the list.

Access to multiple-use federal government lands is a critical concern because they hold the relatively under-explored and not-yet-producing gas resources for the future. This is compared with private and state lands that have been more fully explored and developed.

(Other challenges include technology, financing, workforce, the physical infrastructure including rigs, lead times, and the requirements of the new customer base which includes the new Independent Power Producers.

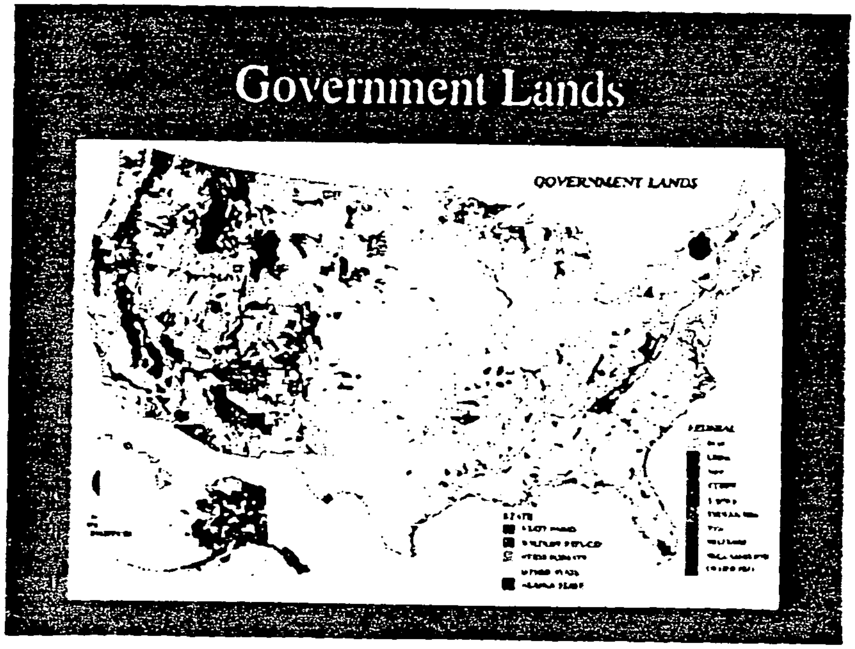
A positive partnership between government and industry is essential in meeting all the NPC-identified challenges to finding and producing the natural gas we'll need to meet the nation's economic and environmental goals.)



Access to the resource base and to rights of way for infrastructure is critical for sustainable supply.

Of the almost 1,500 TCF of lower 48 resource base cited in the NPC study, approximately 47% is owned by the Federal Government. But the resource base under Federal Government lands is far more critical than that percentage might imply. As mentioned previously, that's because state and private lands have been much more fully explored and developed with respect to energy resources. By contrast, the Federal Government lands are relatively under-explored. For example, it is estimated that 90% of the Federal Government lands resource base in the Rockies is unproven and clearly not yet available to consumers. What's more, offshore drilling moratoria have virtually closed activity in the Eastern Gulf, Atlantic and Pacific Coast waters under Federal jurisdiction. It is important to note that technology has advanced to a point that we can assess and develop resources in these areas more efficiently, and with less environmental impact, than ever before.

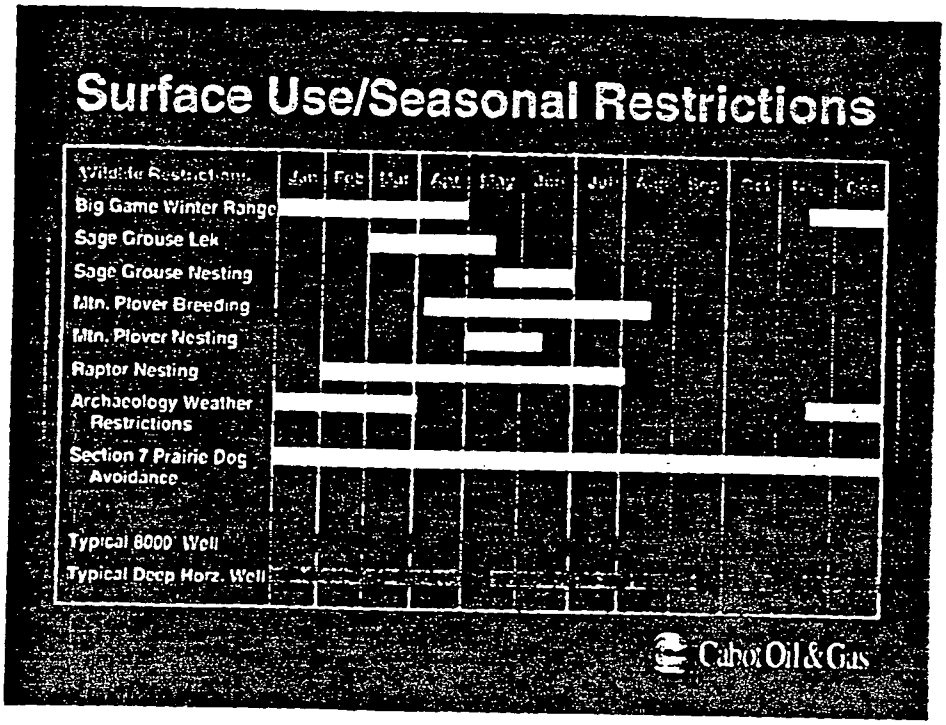
The map above illustrates the total lower-48 natural gas resource base and the percentages of it that are either completely off-limits or is access-restricted according to the NPC. (This is based on modeling such factors as complete activity prohibition, no-surface-occupancy stipulations, two-year or greater delays and cost increases. Later examples dramatically illustrate these factors.)



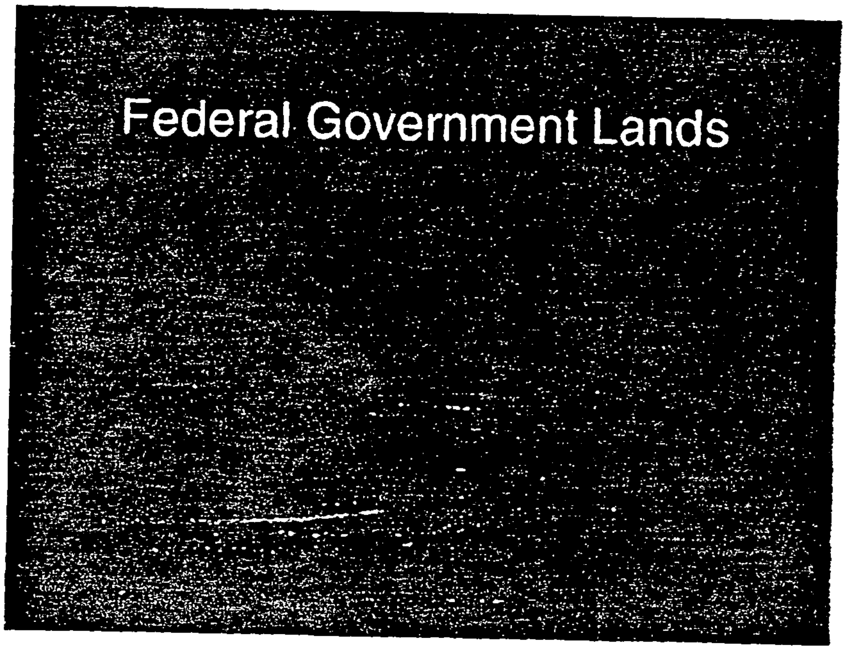
As can be seen on this map, a significant portion of the Rocky Mountain area -- including some 75.8 percent of the natural gas resources according to the NPC -- is owned by the Federal Government, and managed either by the BLM or the Forest Service (US Department of Agriculture). It should be noted that the industry is not advocating drilling in National Parks. However, a significant portion of the yellow (BLM) acreage in the states of Wyoming, Colorado, New Mexico and Utah has considerable gas potential. Meaningful cooperation among these entities and industry will be required to access this important area of natural gas supply.

Let me give you some examples of restrictions that we believe can -- and must -- be dealt with.

Last year Bureau of Land Management officials in New Mexico announced new criteria for approval of applications for permits to drill in the San Juan Basin while it conducts a new environmental impact statement in preparation for updating its resource management plan. Had the criteria, including announced moratoria on some applications, been put into effect as announced, critical California gas supply from this mature producing area could have been reduced. Strong protests led to changes in the New Mexico policy while the EIS is done, but with the current APD backlog and pace, it is still uncertain whether there will be enough drilling over the next year or two to meet supply needs.



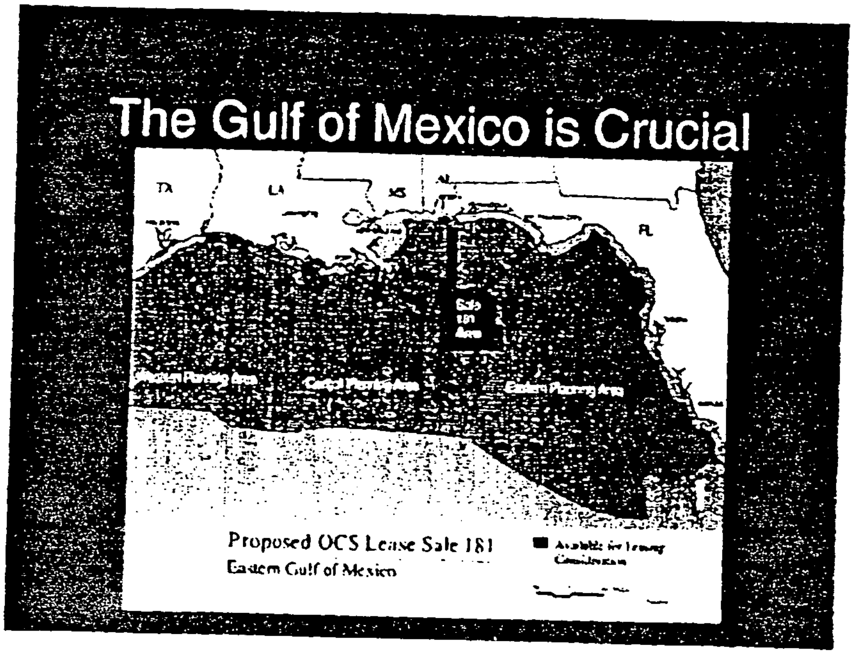
A prime example of this type of problem is illustrated by the time line chart you see here for BLM land in Southwest Wyoming. With the layering of wildlife protection and other environmental restrictions in parts of the year, you can see that there are only limited periods in which necessary natural gas exploration and production drilling by one of our member companies can occur. As you can also see, some deep wells that take longer than the allowed drilling window either will not be drilled, or must be drilled in inefficient and probably prohibitively expensive phases over more than one year.



Let me pause here for a moment to point out that much of the land we are discussing is like that shown above in Wyoming. With our current technology we can explore and produce gas on these lands with much smaller drilling locations, or "pads", than in year's past. Improved geoscience technology allows us to better target promising geologic formations below ground, so we drill fewer wells. But we still must drill to find and produce gas. Then we reclaim the land to its original condition.

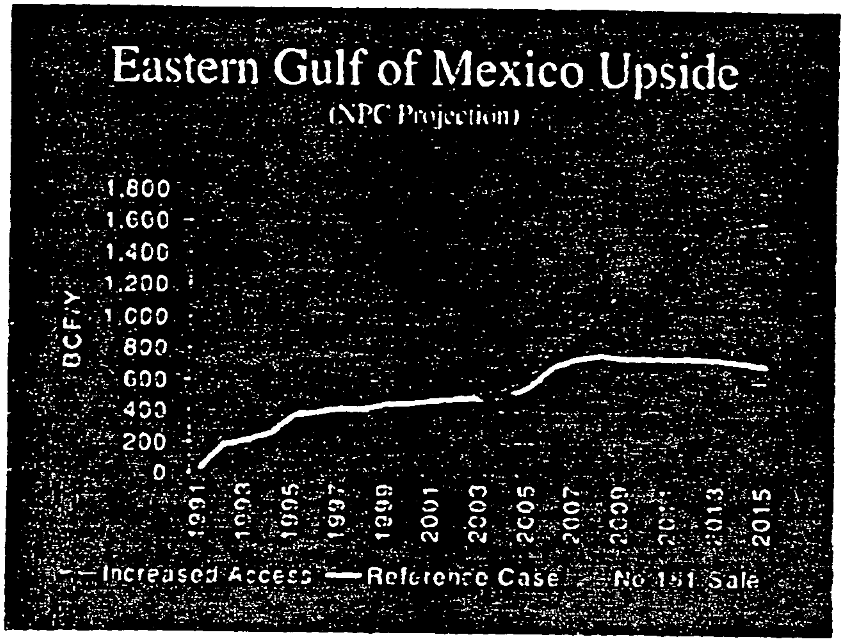
But to move to another example of restrictions, in Southwest Wyoming a permit for an exploratory well was denied last fall despite explicit provisions of an "interim Drilling Policy" that was in effect while a new Environmental Impact Statement was being prepared. Total company costs related to the EIS itself and the delays in permitting that have occurred to date, and could occur in the future may run over $2-million—enough to drill six additional wells and bring them on line.

One final onshore case. In the Monongahela National Forest of West Virginia, inconsistency in the directives provided by Forest Service specialists in the preparation of an Environmental Assessment caused ten revisions over a span of 2 years. Several revision drafts duplicated previous drafts that had been rejected by the Forest Service personnel. Such delays obviously add to costs, but they also delay or prevent gas from flowing to consumers.



Now an important word about the offshore. As the NPC study pointed out, and as we in our industry know, with both of our coasts off limits to exploration and production -- the Gulf of Mexico, including its deep waters, will be crucial in meeting gas demand.

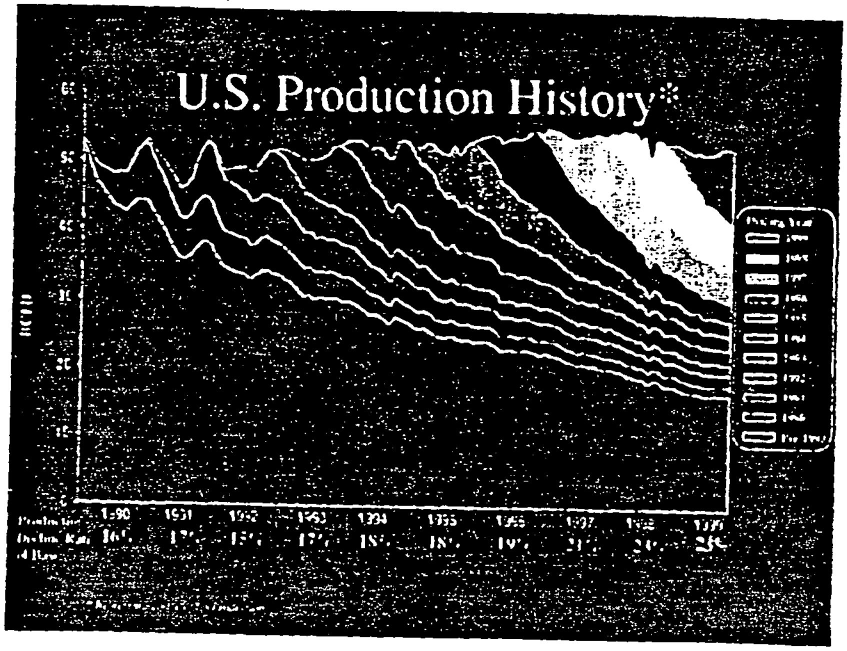
Lease Sale 181 in the Eastern Gulf of Mexico, scheduled for December of this year, provides an outstanding example of what we need to be doing. It alone could make a significant 400 BCF per year contribution to providing natural gas to Florida and the surrounding region to meet increasing electricity generation needs.



This chart illustrates the NPC's projection of the impact of access restrictions in the eastern Gulf of Mexico. The Reference Case curve (middle line) assumes that Western Norphlet, off the coast of Mobile, Alabama, and MMS Lease sale 181 will be the only areas in the eastern gulf that will produce gas.

Also shown here is the impact if sale 181 did not happen (bottom line). As noted a moment ago, this is a potential 400 BCF per year loss of valued natural gas resource.

However, as the top line indicates, the NPC study anticipates substantial additional gas supplies to feed the country's growing energy demand if industry is allowed access beyond the Western Norphlet and Sale 181 areas.



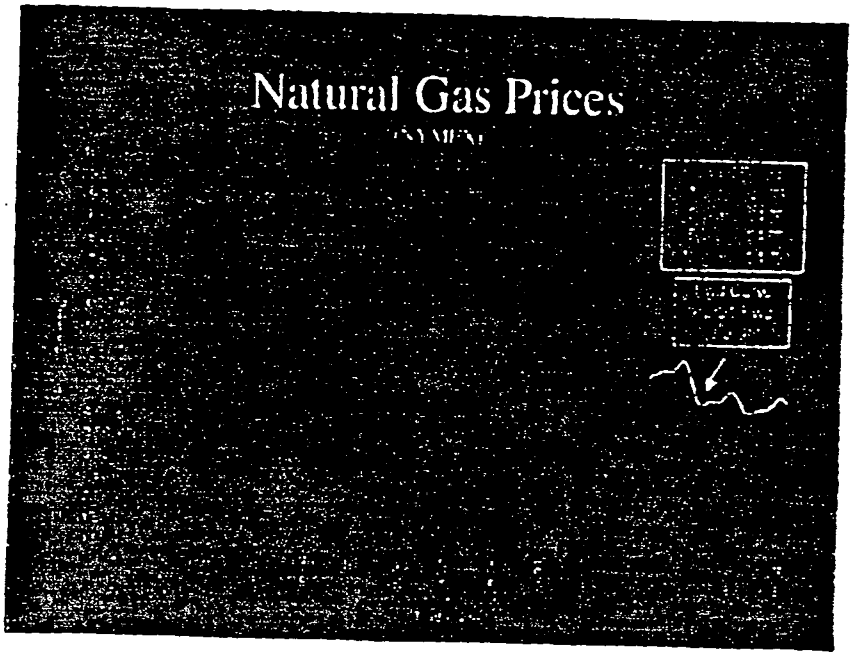
To begin to conclude, as this slide shows, over the past decade production from the wells we have drilled every year has declined more sharply. That's because, with current access restrictions,

1) new field discoveries tend to be smaller in size; and,

2) drilling and completion technological advances have enable higher flow rates, resulting in shorter reserve lives as we drill and produce smaller fields.

This means that drilling rates will have to increase to meet projected demand.

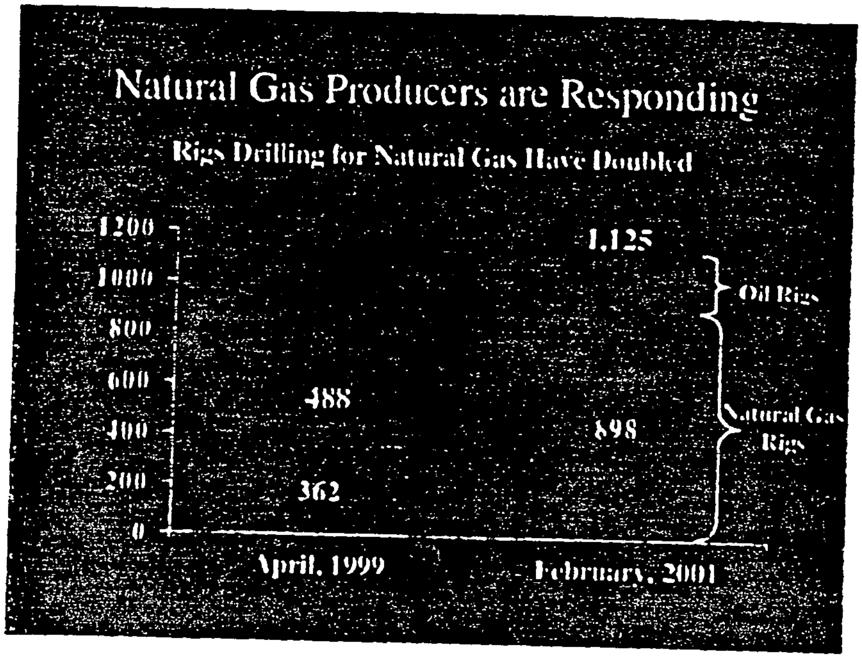
Again, to accomplish this we must meet the challenges we discussed -- including investments in finding and training people for our increasingly technology-oriented industry -- and new equipment. But access to the remains the key to the responsible development of natural gas as a precious natural resource.



Since the NPC study was completed in late 1999, the access and regulatory issues I have been discussing have not been addressed. In fact, access has become more and more problematic in recent years.

One result of our current situation has been a tight natural gas market in which such factors as a cold winter and unexpected strong demand in the electric generation sector can cause the price history shown here by the red, or dark, line.

The good news for the future is shown by the lighter, or yellow line to the right -- the futures market beginning to respond by predicting lower prices, though still strong by comparison with most of the past decade or so. That's in part because of the extraordinary efforts our industry is making to meet consumer demand.



As discussed on the previous slide, producers are responding to market signals.

Today, with tight supply and rising demand, producers are individually responding by working to bring more natural gas to the market. One economic indicator is the Rotary Rig Count. Natural gas drilling rigs have increased by 143% since April 1999, when prices were at their lowest.

Equally important, almost 80% of the rigs being used today are looking for natural gas, up from 75% in April 1999.

Policy Recommendations

- Administration
  - Energy Policy Directive to All Departments and Agencies
  - Prompt Permitting Review and Benchmarking Program

We have recommended to the Administration that several steps be taken to seek better coordination of energy permitting. Included among them are:

•a directive that all resource agency policy and implementation decisions take energy implications into account; and,

•a quick benchmark survey of permitting by every state, area and Forest group within the Bureau of Land Management and the U.S. Forest Service to identify where things are being done well – and efficiently – and where improvements need to be made. (This would also help identify areas and offices in need of more resources, and would be a valuable budget tool.)

Then a quick program should be started to bring all parts of these agencies to the higher performance level.

Perhaps your Subcommittee and the Congress as a whole can help in these areas through legislation or oversight.

Policy Recommendations

- Congress
  - Expedite Federal Government Lands Energy Resource Review.
  - Consider Streamlined Process for Eliminating or Easing Access Restrictions

In addition, we support the ongoing congressionally mandated inventory of energy resources on federal government lands, but it should be expedited.

Even more important, Congress and the Administration should use the time during which the inventory is being undertaken to consider whether there should be a simplified process to allow states and their congressional delegations to seek removal of access restrictions where there is little or no benefit at the cost of energy supplies, and to improve permitting processes and coordination where problems are identified.

We look forward to continuing to working with you especially on this crucial element of a comprehensive and consistent national energy policy.

I appreciate the opportunity to be with you to discuss such important energy issues, and I would be glad to answer any questions you may have.

224

GROPPE LONG & LITTELL

GROPPE, LONG & LITTELL

OIL AND GAS ANALYSTS AND FORECASTERS

HENRY GROPPE E.W. LONG, JR. GEORGE S. LITTELL

1111 BAGBY, SUITE 2330
HOUSTON, TEXAS 77002

PHONE (713) 658-1193
FAX (713) 658-1196

WEBSITE www.groppelong.com
EMAIL gll@groppelong.com

THE WORLD OIL AND NORTH AMERICAN GAS OUTLOOK

February, 2001

797

GROPPE LONG & LITTELL

CONTRASTING FUNDAMENTALS

World Petroleum
(Excluding Eastern Europe)

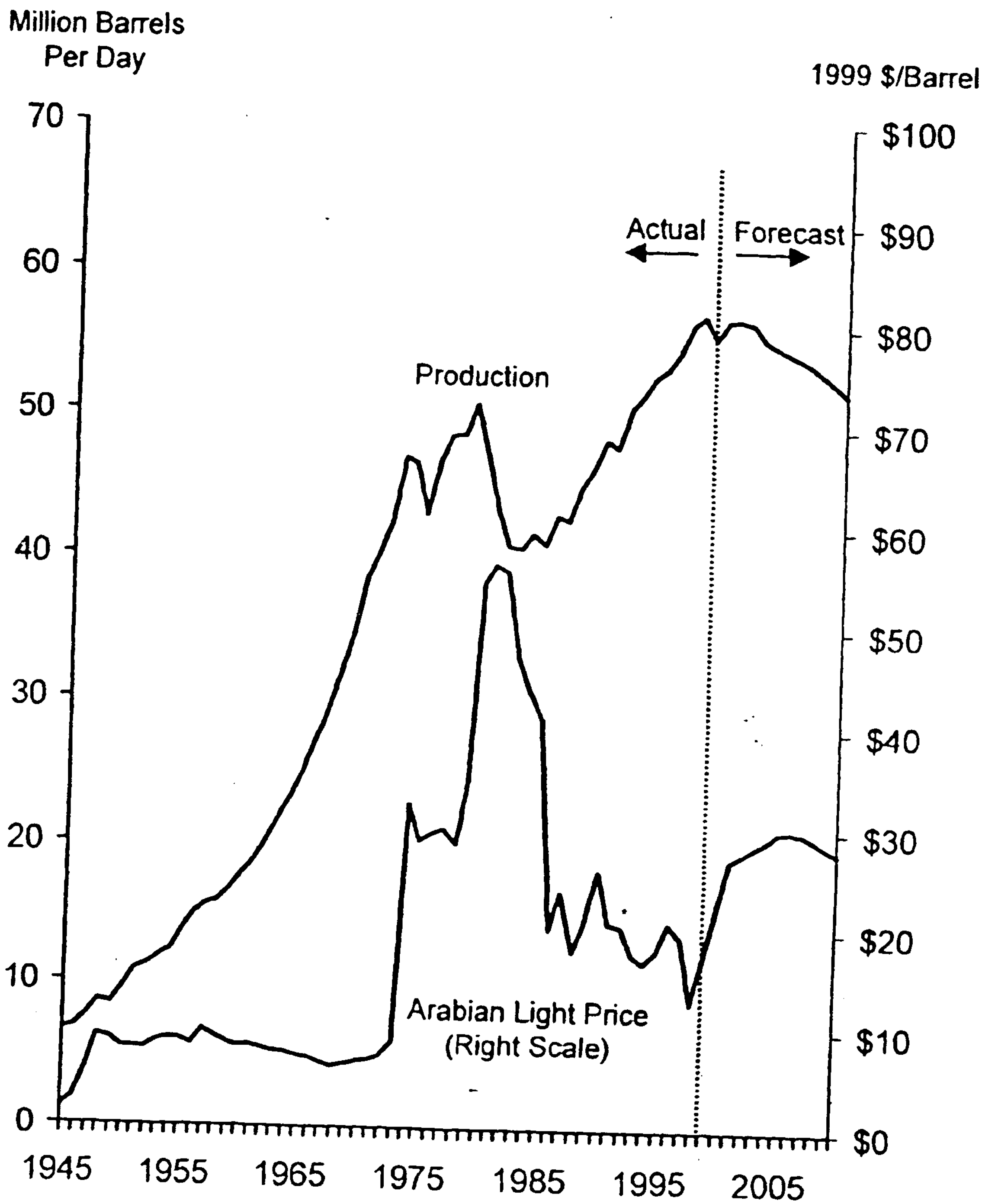
	1979 – 1986	1986 - 2000
Consumption Change		
Million Bbls/Day	-5	+19
Excess Capacity		
Million Bbls/Day	13	3.5
Number of Countries	11	5

U.S. Natural Gas

	1979 – 1986	1986 - 2000
Consumption Change		
Billion Cu. Ft./Day	-10	+18
Excess Deliverability		
Billion Cu. Ft./Day U.S.	12	0
Canada	3	0

GROPPE LONG & LITTELL

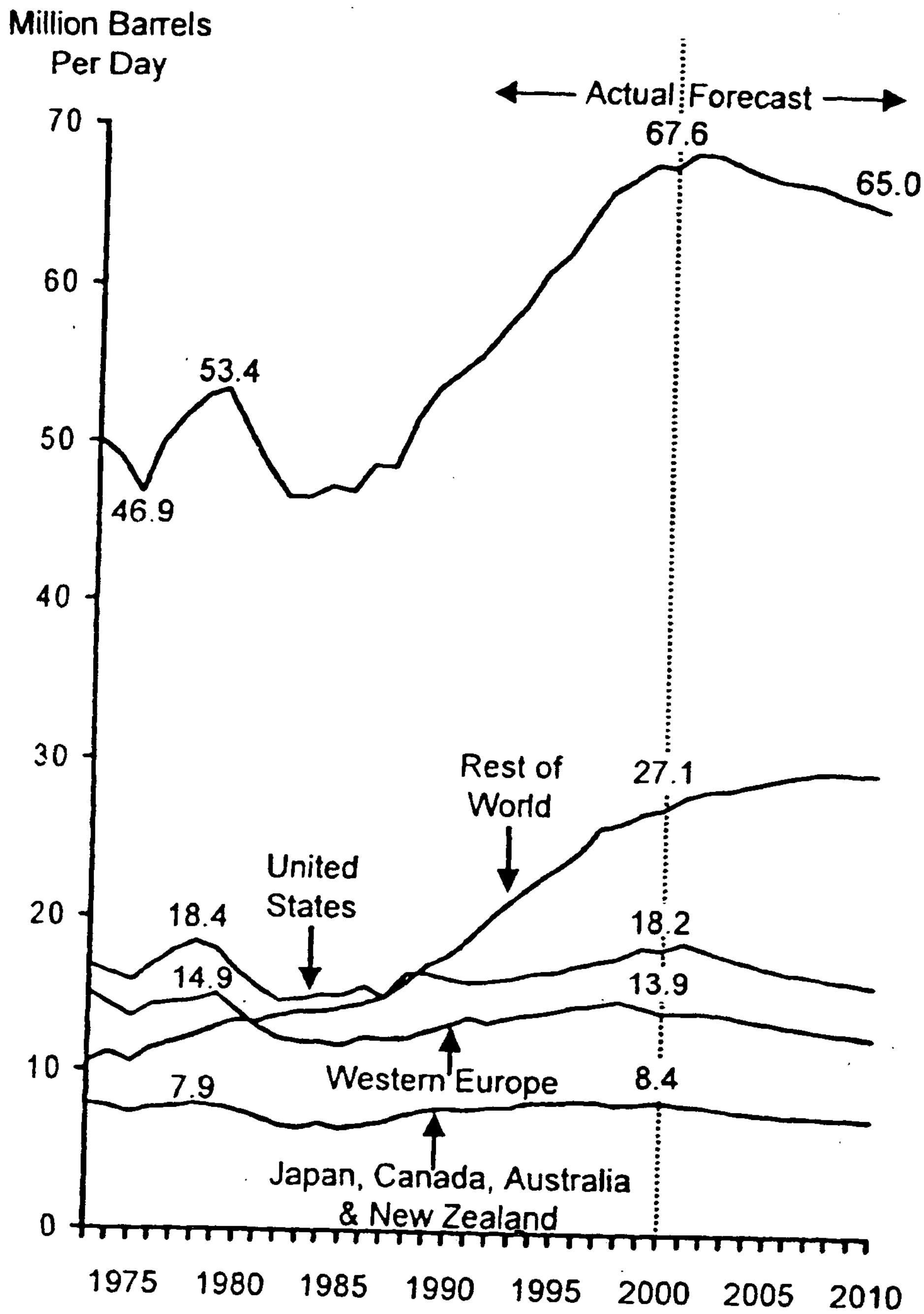
WORLD CRUDE OIL PRODUCTION
(Excluding Eastern Europe)



DOE002-0809

GROPPE LONG & LITTELL

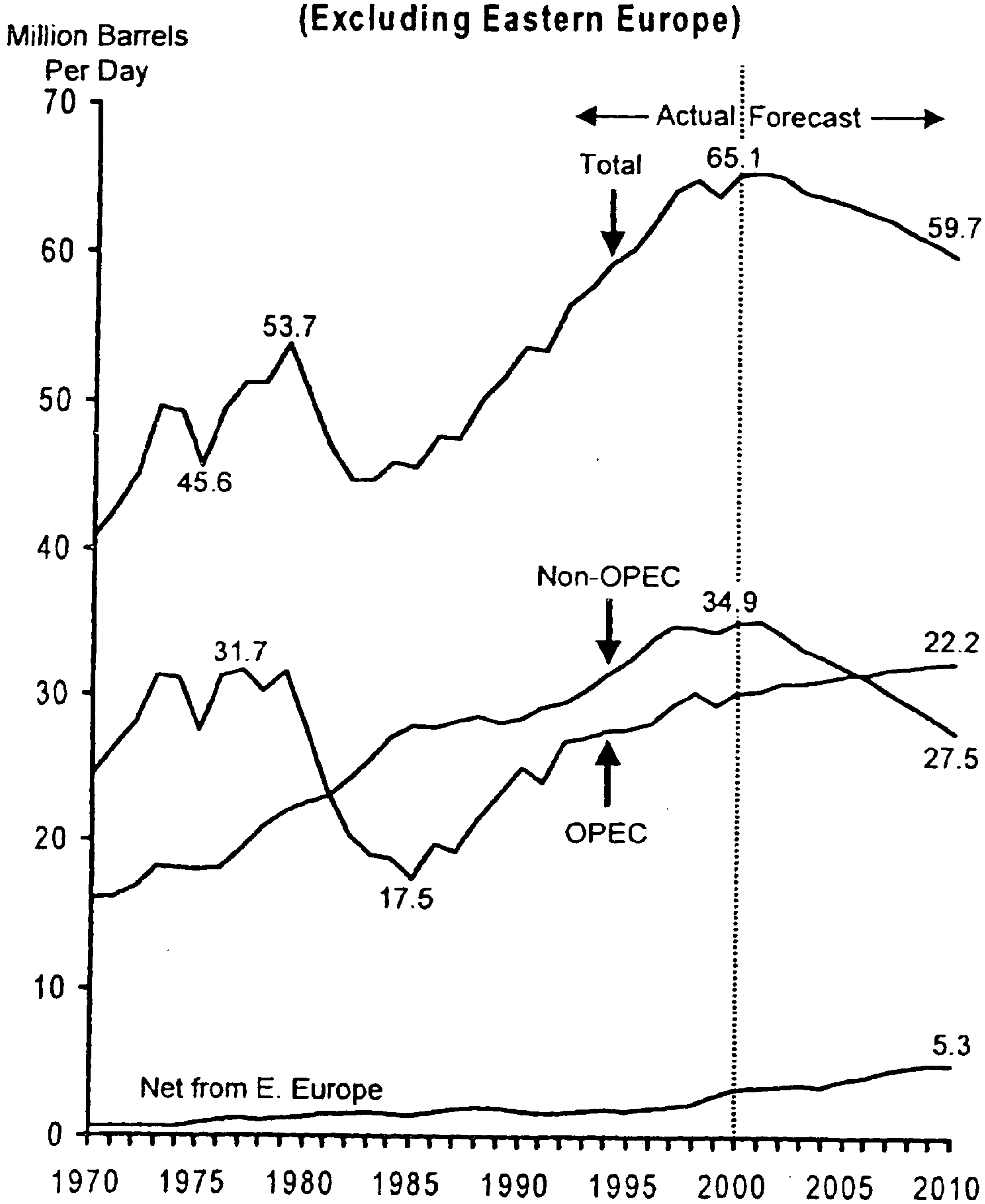
WORLD PETROLEUM DELIVERIES
(Excluding Eastern Europe)



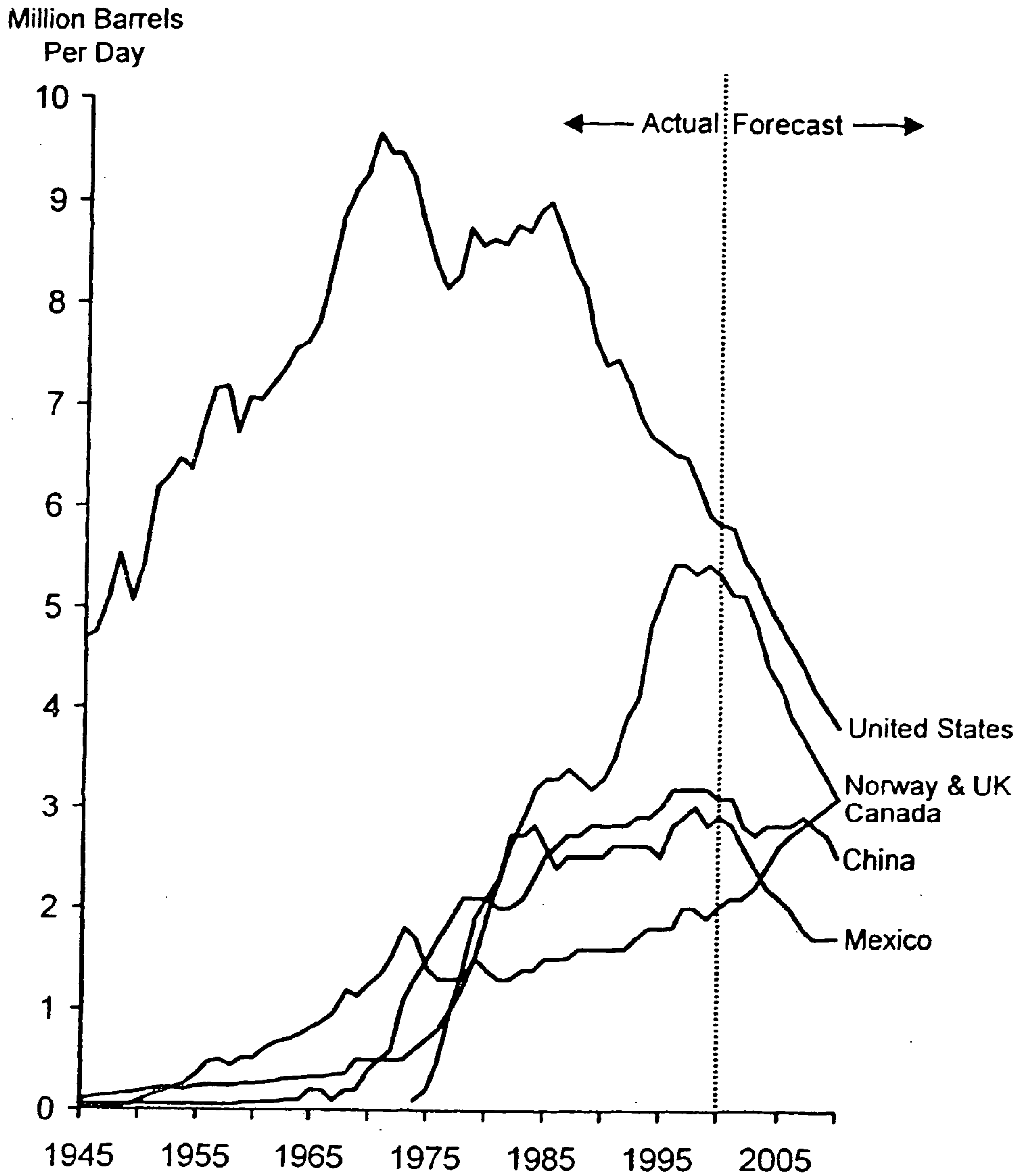
800

GROPPE LONG & LITTELL

WORLD PETROLEUM PRODUCTION
(Excluding Eastern Europe)



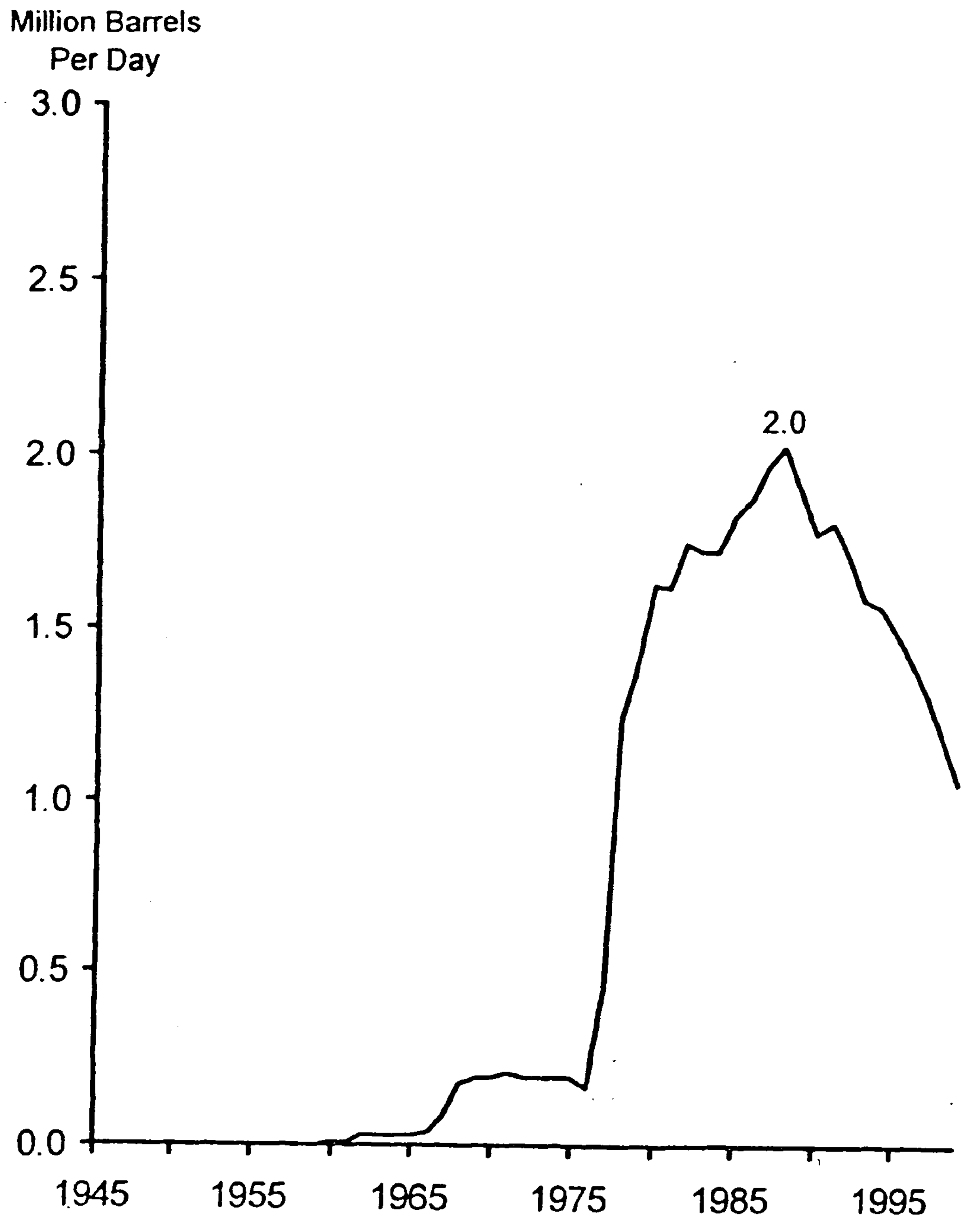
NON-OPEC CRUDE OIL PRODUCTION



DOE002-0812

GROPPE
LONG &
LITTELL

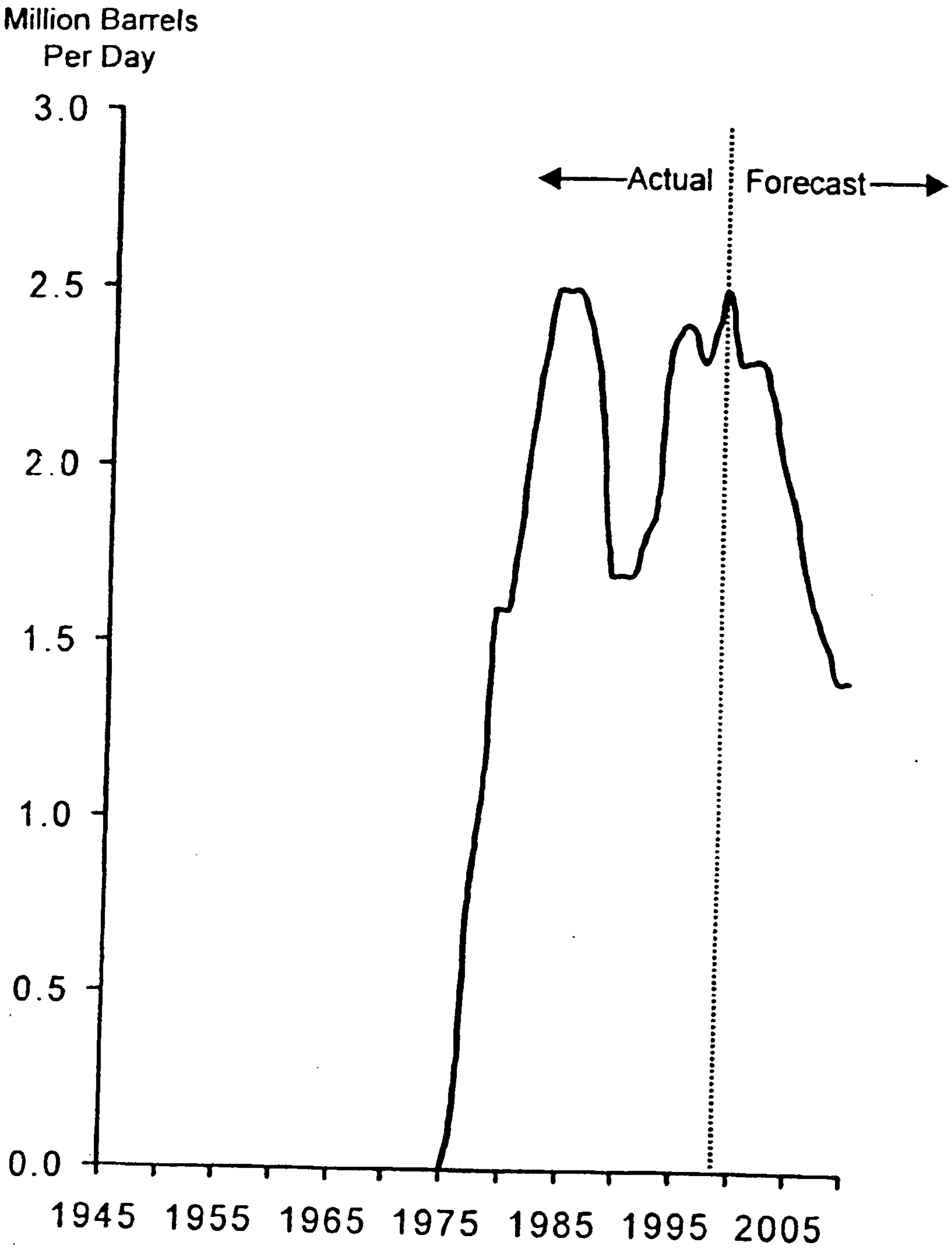
ALASKA CRUDE OIL



DOE002-0813

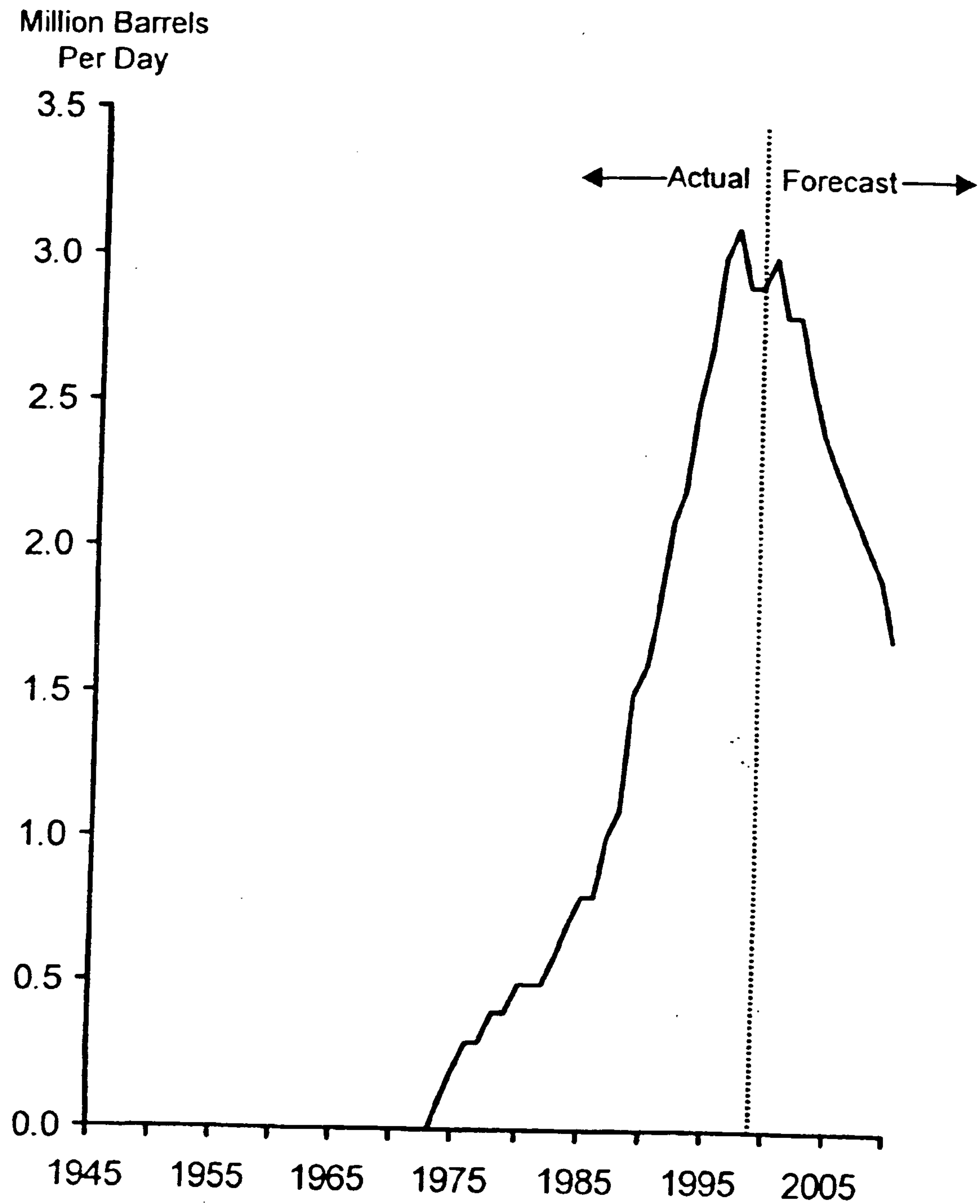
GROPPE LONG & LITTELL

UNITED KINGDOM CRUDE OIL



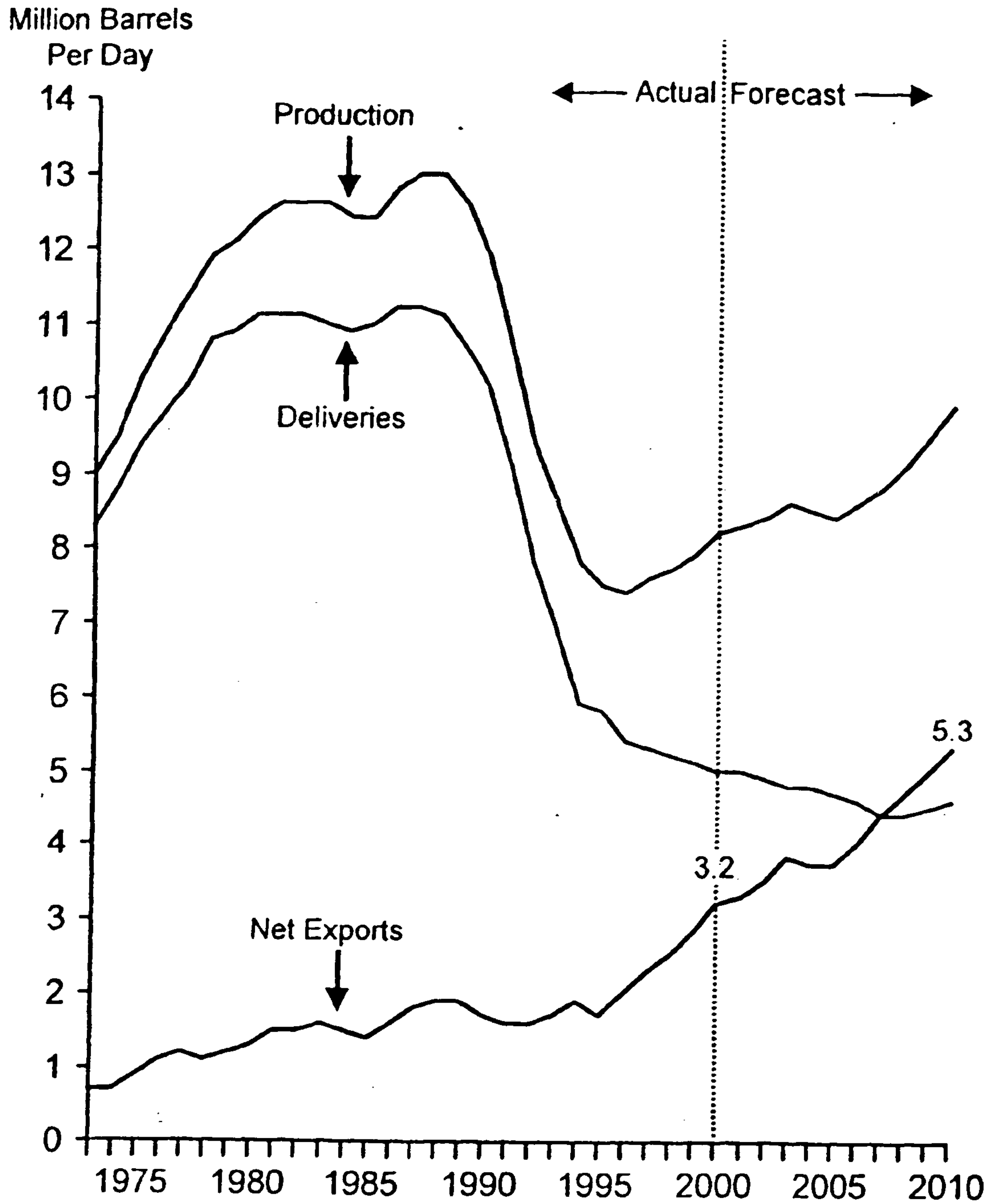
GROPPE LONG & LITTELL

NORWAY CRUDE OIL



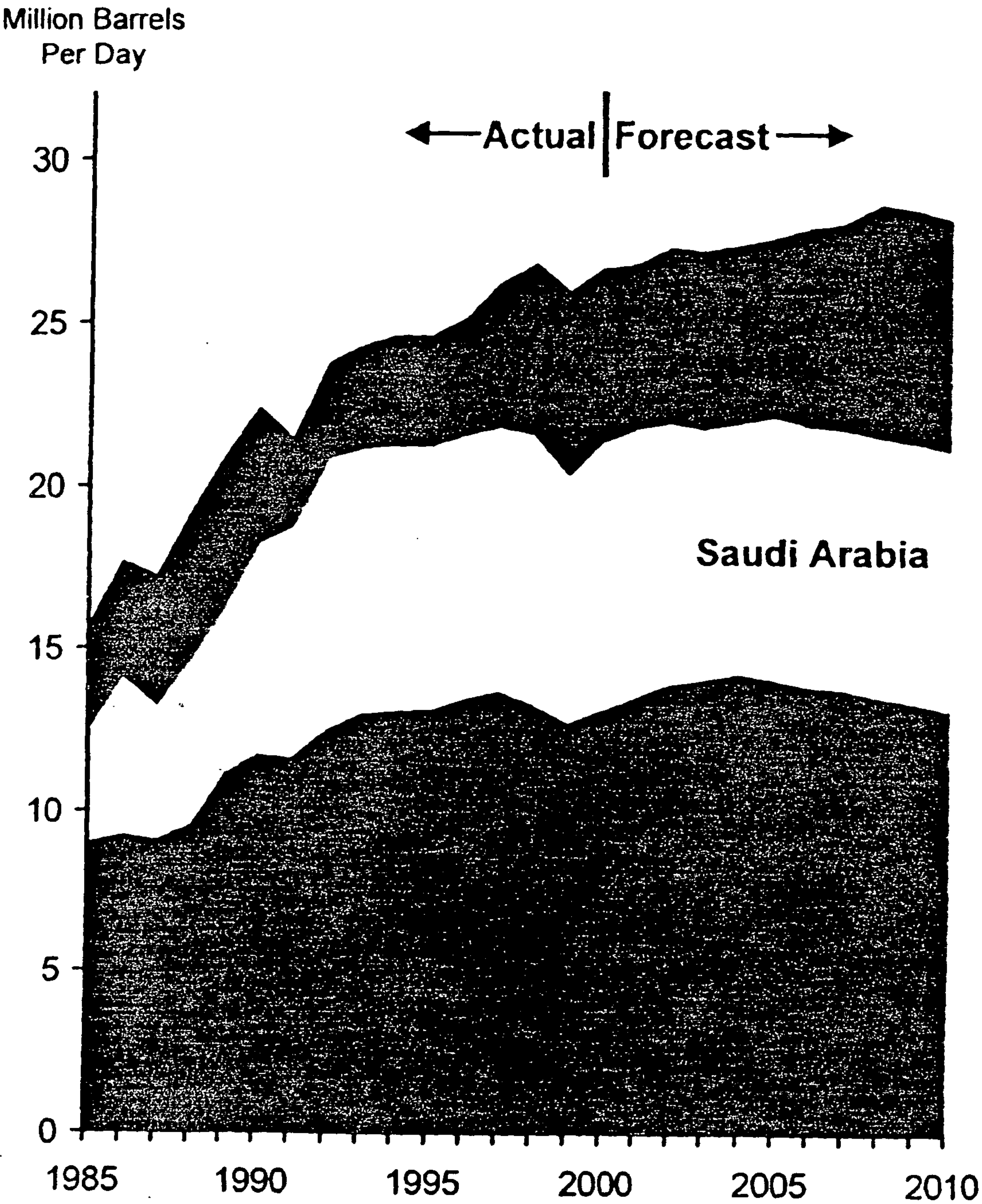
GROPPE LONG & LITTELL

EASTERN EUROPE PETROLEUM PRODUCTION, CONSUMPTION & EXPORTS



GROPPE LONG & LITTELL

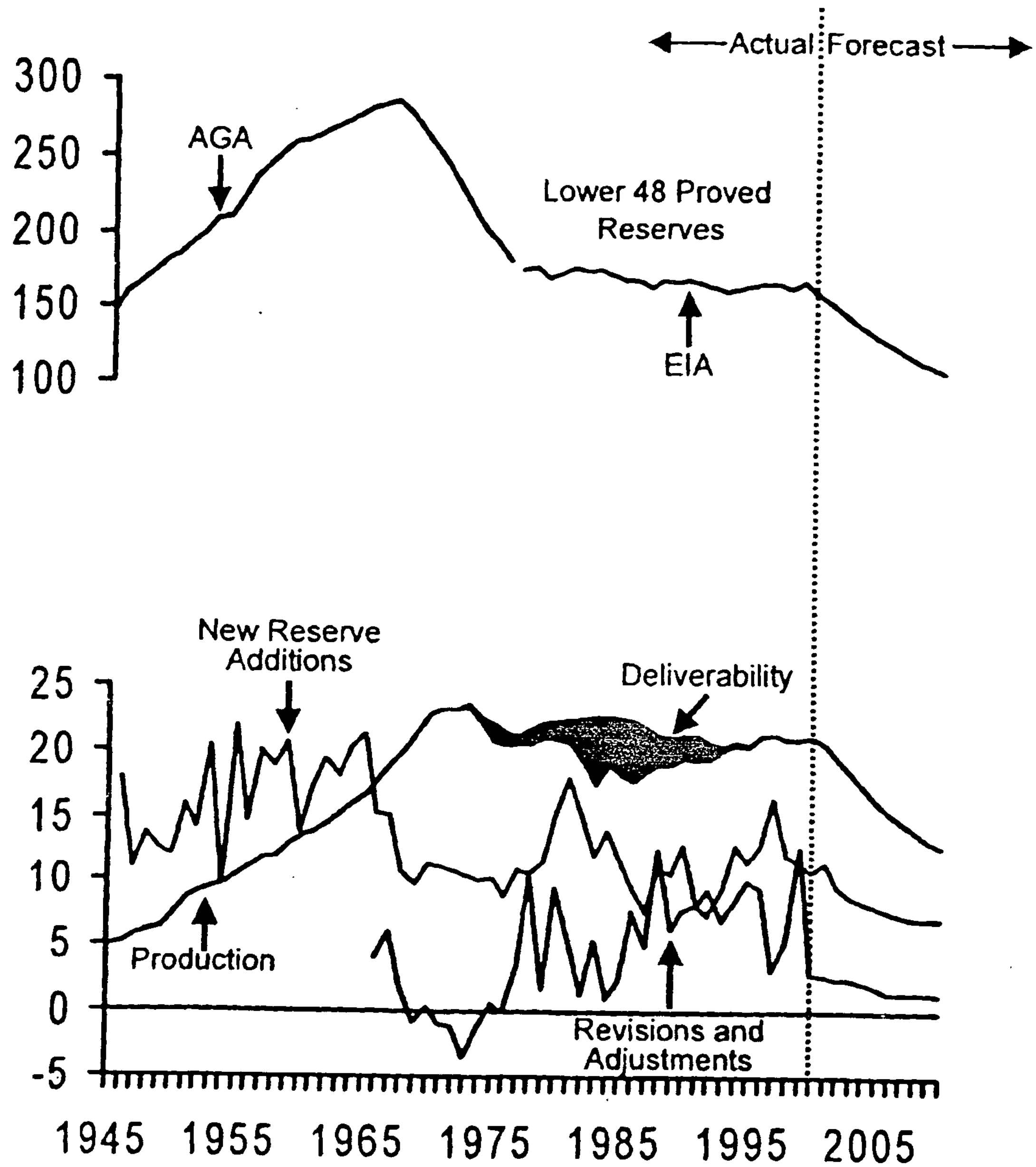
OPEC CRUDE OIL PRODUCTION



* Excludes Ecuador & Gabon who withdrew from OPEC in 1993 & 1996 respectively

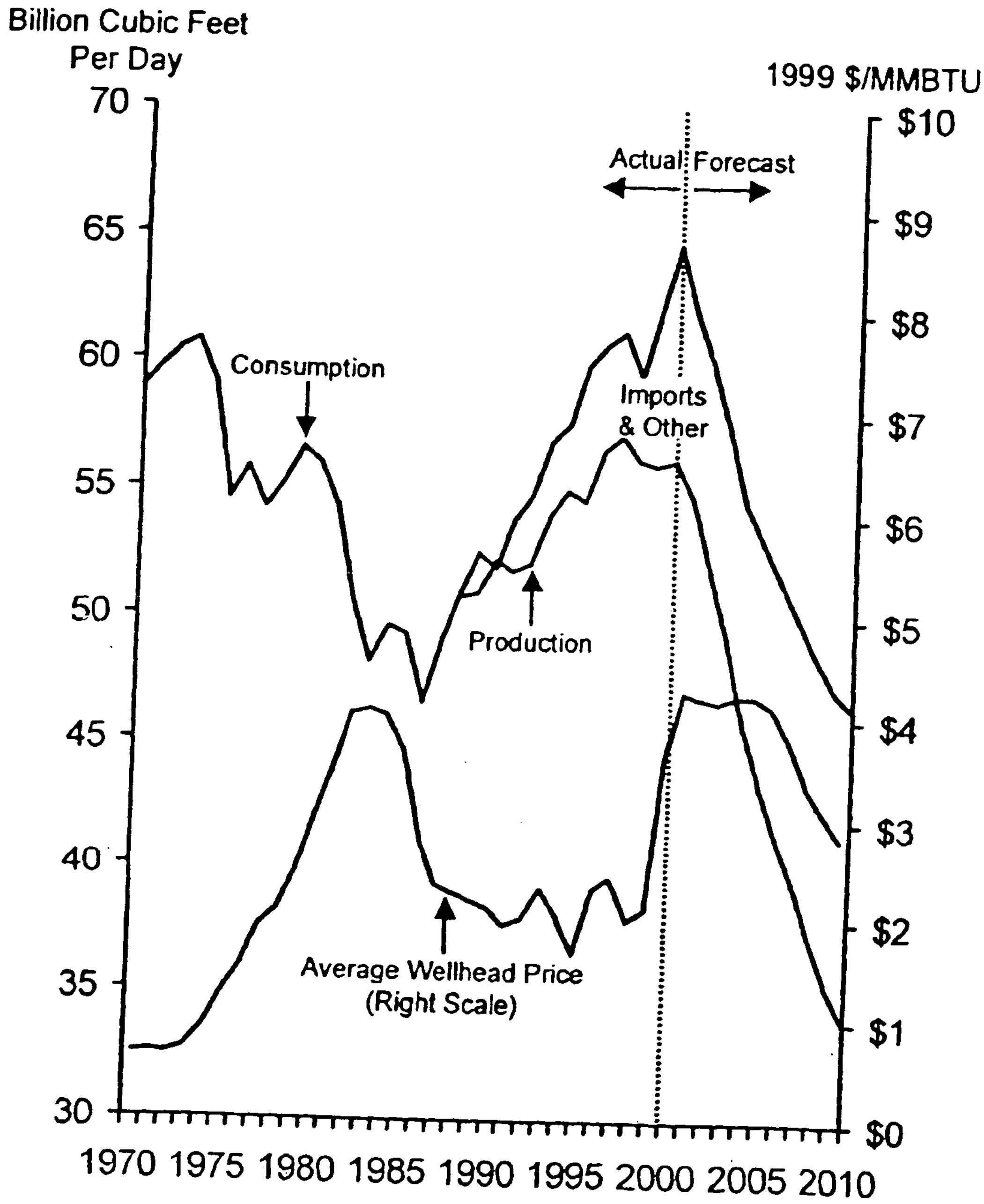
GROPPE LONG & LITTELL

UNITED STATES NATURAL GAS
Trillion Cubic Feet



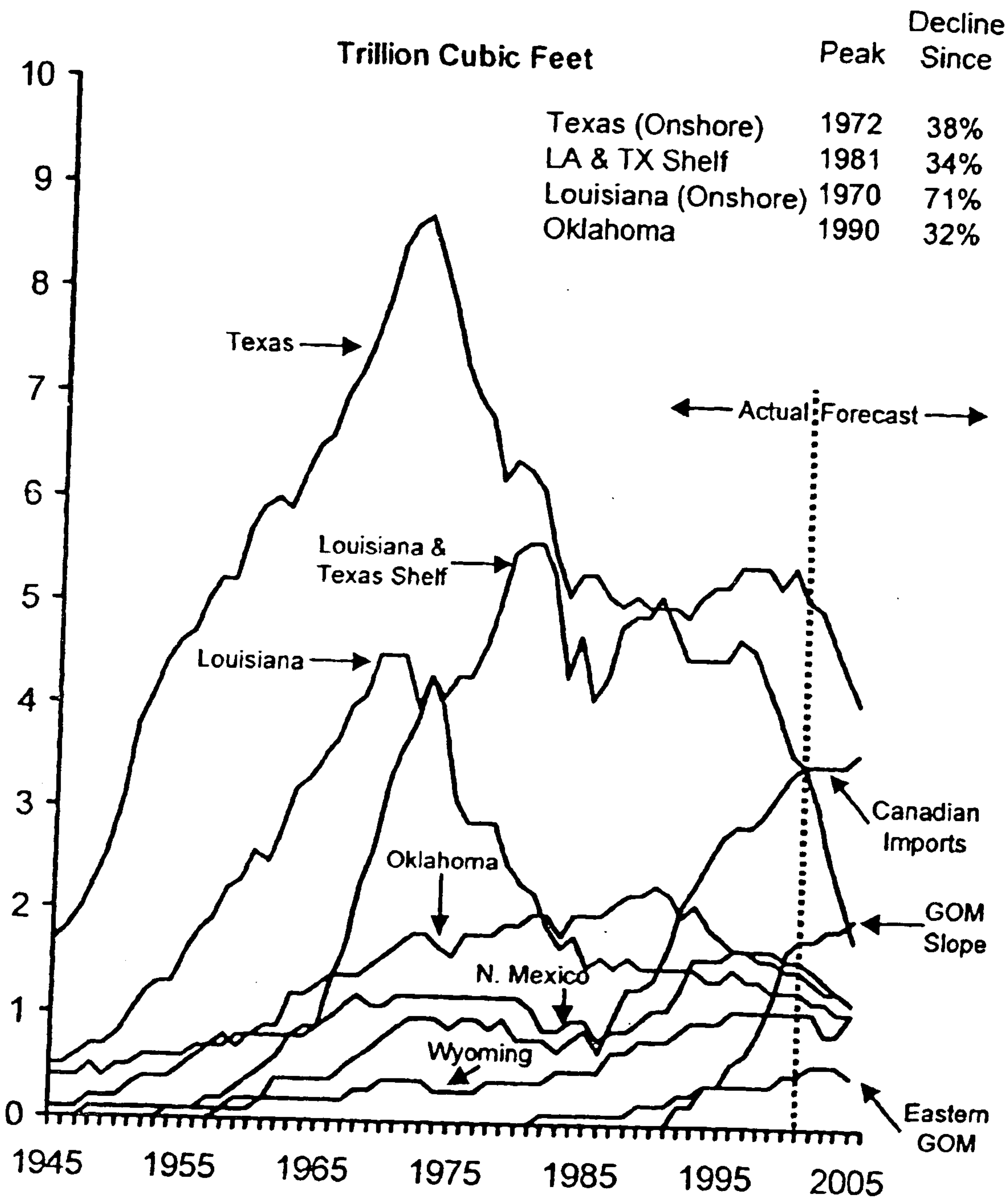
GROPPE LONG & LITTELL

U.S. NATURAL GAS CONSUMPTION, PRODUCTION AND PRICE



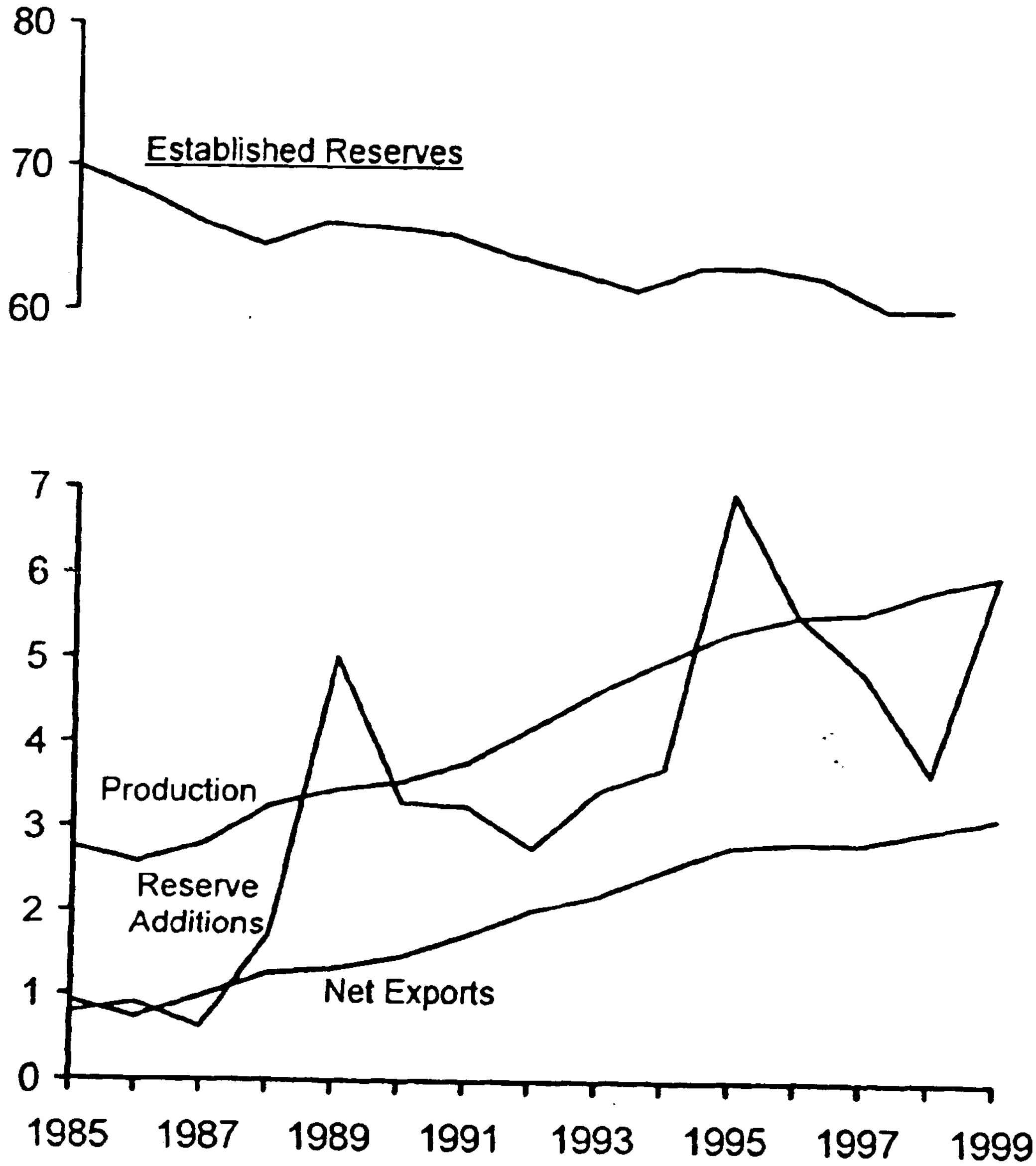
GROPPE LONG & LITTELL

U.S. NATURAL GAS SUPPLY FROM MAJOR SOURCES



GROPPE LONG & LITTELL

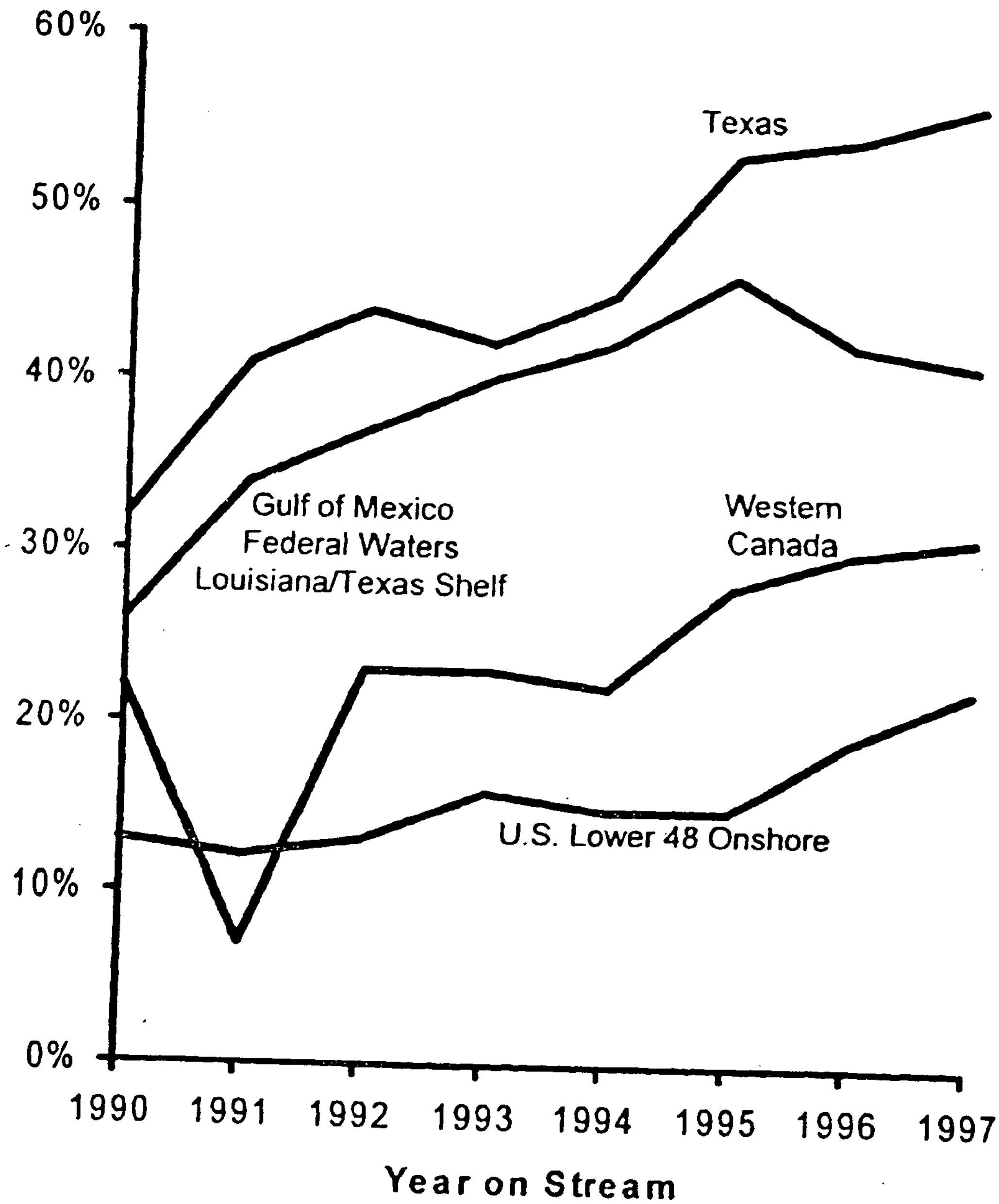
CANADIAN NATURAL GAS
(Excluding Frontier Areas*)
Trillion Cubic Feet



* Mackenzie Delta, Beaufort Sea, Artic Islands, and East Coast Offshore

GROPPE LONG & LITTELL

FIRST YEAR NATURAL GAS PRODUCTION DECLINE RATES



225

PRESS RELEASE

January 29, 2001

CSIS . . .
www.csis.org
About CSIS
Scholars
Research
News & Events
Periodicals
Publications
Press Page
Press Releases
Conference Advisories
CSIS Web Flash
CSIS on the Hill
Employment/ Internships
Search CSIS

Programs & Projects on the web

Africa
Americas
Asia
Energy
Eastern Europe
Europe
Enterprise for the Environment
Global Aging
Global Information Infrastructure Commission

GEOPOLITICS of ENERGY

U.S. Lacks Strategic, International Policy; New Supply Threats Emerge

Contact: Mark Schoeff Jr. 202-775-3242, Lisa Hyland 202-775-3115

WASHINGTON, Feb. 14, 2001 - U.S. energy policy lacks global perspective and contains inherent contradictions, potentially making it difficult to meet emerging supply threats, according to a CSIS report.

"The Geopolitics of Energy into the 21st Century," a three-volume report of the CSIS Strategic Energy Initiative, assesses the international energy supply-and-demand relationships and geopolitical developments likely to affect global energy markets between 2000 and 2020. The report is available at www.csis.org/sei/geopoliticsexecsum.pdf

"At some point during the next 20 years, the developing world will begin to consume more energy than the developed world," the report states. "Energy supply will need to be expanded substantially to meet this demand growth. Central to the geopolitics of energy during 2000-2020 is the fact that energy demand will be met in essentially the same ways as it was met at the end of the twentieth century."

As this scenario unfolds, the U.S. must take a different policy approach. "**The United States deals with energy policy in domestic terms, not international terms; U.S. energy policy is therefore at odds with globalization.** Under globalization, we are vulnerable to any event disrupting energy supply or demand anytime and anywhere," said Robert Ebel, director of the CSIS Energy Program. "The SEI report provides background and guidance for energy policy reform." Among the recommendations:

- **Avoid indiscriminate use of sanctions.** "If global oil demand estimated for 2020 is reasonably correct and is to be satisfied, Iran, Iraq, and Libya should by then be producing at their full potential if other supplies have not been developed."
- **Do not obstruct Caspian, Central Asian development.** "Tying exports primarily to one pipeline route-with the goal of avoiding Iran and Russia as transit states-before the political and economic viability of the route is known may undercut the pace of energy development in the region."
- **Increase foreign investment** in energy-producing countries.
- The United States must **protect worldwide energy supply** with greater burden sharing by allies.
- Governments and the private sector must work together to protect energy infrastructure against sabotage or terrorist attack, including **cyberterrorism**.
- **Economically and environmentally sound technologies**, including cost-competitive nuclear electric power, must be made

available to help developing countries meet increasing energy demands.

The SEI consisted of a 65-member task force and 16-member advisory board. The SEI cochairs were Sens. **Frank Murkowski** and **Joseph Lieberman**, Reps. **Ellen Tauscher** and **Benjamin Gilman**, former Sen. **Sam Nunn**, chairman of the CSIS board, and former secretary of energy **James Schlesinger**, a CSIS counselor.

CSIS is an independent, nonpartisan public policy research organization

CSIS
1800 K St., NW
Washington, DC
20006
ph: 202.887.0200
fax: 202.775.3199

Email the Webmaster

Executive Summary

The Center for Strategic and International Studies (CSIS) launched its Strategic Energy Initiative (SEI) in mid-1998 on the premise that the benign global energy situation that had prevailed since the late 1980s masked two dangers.

First, it obscured significant geopolitical shifts both ongoing and forthcoming that could affect future global energy security, supply, and demand.

Second, it led to complacency among policymakers and the public about the need to incorporate long-term global energy concerns into near-term foreign policy decisions.

By midyear 2000 the state of the world oil market had undergone considerable turbulence, marked by rapidly rising oil prices as oil-exporting countries were benefiting from staged reductions in production that had been initiated more than two years earlier. The delicate balance between supply and demand was demonstrated once again.

Instead of dwelling on the oil market turbulence in 2000, however, this report assesses the international energy supply-and-demand relationships likely to prevail in the first two decades of the twenty-first century, highlighting the different ways that geopolitical developments could affect global energy markets between 2000 and 2020. In light of the world's future energy needs, this report series also points out the contradictions inherent in certain of the energy objectives and foreign policies pursued by the United States and other Western governments. Finally, the report offers policy considerations that, if implemented, could help ensure that energy supplies are adequate to meet projected worldwide demand, are not excessively vulnerable to major interruptions, and are produced in ways that minimize damage to the environment.

It may appear that parts of this assessment are unduly pessimistic, that positive factors have been overlooked. These SEI assessments do stress prospects for instability and for interference in energy supplies, but only to alert policymakers about the fragility of reliable and timely supplies.

Energy Outlook to 2020

During the next 20 years, providing there is no extended global economic dislocation, energy demand is projected to expand more than 50 percent. This growth will be unevenly distributed, with demand increasing in the industrialized world by some 23 percent while more than doubling, from a much lower base, in the developing world, with Asia accounting for the bulk of this increase. At some point during this period, the developing world will begin to consume more energy than the developed world. Energy supply will need to be expanded substantially to meet this demand growth. Although the Persian Gulf will remain the key marginal oil supplier, all producing countries must contribute to supply to the extent they can.

Central to the geopolitics of energy during 2000–2020 is the fact that energy demand will be met in essentially the same ways as it was met at the end of the twentieth century. Fossil fuels will provide the bulk of global energy consumption, rising marginally from an 86 percent share in 2000 to an 88 percent share in 2020. Although oil will dominate global energy use and coal will retain its central role in electricity generation, natural gas use will increase noticeably. Indeed, the relative contributions of oil and coal to world energy consumption will actually decline whereas only natural gas will demonstrate a growth in both absolute and relative terms. Nuclear power will decline in both relative and absolute terms; renewables, including hydropower, and alternative energy sources, while growing in absolute terms, will not capture a greater relative share of the market.

Development of oil and gas reserves is judged sufficient to meet projected global demand well beyond this period. The most noticeable trend during 2000–2020 will be the growing mutual dependencies between energy suppliers and consumers. Key aspects of this trend, which are set out below, may appear rather obvious—and they are; how to respond in today's changing environment is much less so.

- The Persian Gulf will remain the key marginal supplier of oil to the world market, with Saudi Arabia in the unchallenged lead. Indeed, if estimates of future demand are reasonably correct, the Persian Gulf must expand oil production by almost 80 percent during 2000–2020, achievable perhaps if foreign investment is allowed to participate and if Iran and Iraq are free of sanctions.
- While the Persian Gulf's share of world oil production continues to expand, the share of North America and Europe, the world's most stable regions, is projected to decline.
- The share of world oil production from the former Soviet Union is projected to increase from 9 percent to almost 12 percent. But, as had been the case in earlier years, this oil will follow the market, not attempt to lead it.
- The Caspian oil contribution to world supply will be important at the margin but not pivotal.
- Asian dependence on Persian Gulf oil will rise significantly, and the resulting necessity for longer tanker journeys will put more oil at risk in the international sea lanes.
- European dependence on Persian Gulf oil will remain significant.
- The European need for natural gas will be covered by a handful of suppliers, Russia being the most significant, which underscores a worrisome dependency.
- U.S. net oil imports will continue their steady growth. a concern but not relevant
- Anticipated growth in the use of natural gas—in considerable part engendered as a fuel for electric power stations—raises a new series of geopolitical issues, leading to new political alignments.

816

DOE002-0826

- Electricity will continue to be the most rapidly growing sector of energy demand; developing economies in Asia and in Central and South America will show the greatest increase in consumption. The choice of primary fuel used to supply power plants will have important effects on the environment.
- Technological change and improvements in energy efficiency have made their mark on recent energy supply-and-demand balances. Future energy supply and demand must reflect not only a continuation of these successes but an acceleration wherever possible.

Geopolitics and Energy: A Symbiotic Relationship

How Might Geopolitics Affect Energy?

Four main geopolitical trends are likely to influence energy supply and demand during the years ahead.

The continuing domestic fragility of key energy-producing states. The world drew some portion of its energy supplies from unstable countries and regions throughout much of the twentieth century. By 2020, fully 50 percent of estimated total global oil demand will be met from countries that pose a high risk of internal instability. A crisis in one or more of the world's key energy-producing countries is highly likely at some point during 2000–2020.

Globalization. Economic globalization will impose new competitive and political pressures on many of the world's leading energy producers and consumers. It will serve as a spur for growth in global energy supply and demand. It could also lead to serious swings in energy prices and demand because country-specific or regional recessions or other influencing events can now be transmitted quickly around the world. In such a globalized world, energy producers and consumers will become ever more sensitive to their mutual interdependence.

The growing impact of nonstate actors. This impact will be evident in three distinct areas. First, adroitly employing new information technologies, nongovernmental organizations (NGOs) will play a growing role in defining the ways that energy is produced and consumed. Second, terrorist groups, with access to the same technologies, will be in a position to inflict great operational damage on increasingly complex energy infrastructures. Third, radical activists will be in a position to disrupt operational infrastructure through cyberterrorism.

Conflict and power politics. The potential for armed conflict in energy-producing regions will remain high. Early in the twenty-first century, as a result, a weakening of U.S. alliance relationships in Europe, the Persian Gulf, or Asia could have major impacts on global energy security. U.S. concerns over the proliferation of weapons of mass destruction (WMD) and the desire to promote democratization and market liberalization around the world will also have a significant effect on key energy exporters. The future viability of the energy-producing states in the Caspian and Central Asia will be shaped by the competing objectives or interests of Russia, the United States, and adjacent regional powers.

How Might Energy Affect Geopolitics?

There are five main ways in which energy may affect geopolitical outcomes:

Swings in energy demand. A dramatic decline in global energy consumption, brought on by economic recession, could trigger instability in many of the world's major energy-exporting countries. Conversely, continued economic growth, accompanied by rising energy demand, would place more power in the hands of the exporters.

Swings in energy supply. Just as demand is vulnerable to sharp shifts up or down, so is supply. If discovery and development of new reserves and the addition of producing capacities match demand growth, an acceptable balance between supply and demand can be maintained. But a number of factors must be satisfied if supply growth is to be encouraged, including an attractive host-country investment climate and the opportunity for acceptable investment returns. At the same time, political events and logistical interruptions can interfere with supply.

Competition for energy in Asia. As countries in Asia seek to secure growing levels of energy imports, two geopolitical risks emerge. First, historical enmities might boil over into armed conflict for control of specific energy reserves in the region. Second, the rising dependence of China on Persian Gulf oil could well alter political relationships within and outside the region. For example, China might seek to build military ties with energy exporters in the Persian Gulf in ways that would be of concern to the United States and its allies.

Energy and regional integration. Energy infrastructure projects may serve to strengthen bilateral economic and political ties in certain instances. In Asia, for example, energy networks, along with trade liberalization, could serve to reduce historical tensions and place Asian economic growth on a firmer footing. Similar forces might come into play in Europe, linking Russia to the European Union (EU); in South Asia, drawing Bangladesh and India closer together; and in the Far East, linking Russia and China.

Energy and the environment. Environmental concerns will have an increasingly important geopolitical bearing on energy decisionmaking by governments, by producers, and by consumers in the next decades. Should governments pursue aggressive strategies for reducing carbon emissions, a new political fault line could emerge between developed and developing countries.

Policy Contradictions and Considerations

The interplay of geopolitics and energy early in the twenty-first century is at the root of an array of complex policy challenges that governments around the world must now confront. The three interlocking policy challenges are to ensure that (1) in the long term, supplies will be adequate to meet the world's energy needs; (2) in the short term, those supplies are reliable and not subject to serious interruptions; and (3) at all times, energy is produced and consumed in environmentally acceptable ways.

Energy Availability

U.S. policy today contains a fundamental contradiction. Oil and gas exports from Iran, Iraq, and Libya—three nations that have had sanctions imposed by the United States or international organizations—are expected to play an increasingly important role in meeting growing global demand, especially to avoid increasing competition for energy with and within Asia. Where the United States imposes unilateral sanctions (Iran and Libya), investments will take place without U.S. participation. Iraq, subjected to multilateral sanctions, may be constrained from building in a timely way the infrastructure necessary to meet the upward curve in energy demand. If global oil demand estimated for 2020 is reasonably correct and is to be satisfied, these three exporters should by then be producing at their full potential if other supplies have not been developed.

History has demonstrated that unilateral sanctions seldom are successful in persuading nations to alter their behavior. Multilateral sanctions provide a broader front and a greater guarantee of success. Multilateral sanctions test the ability and willingness of enforcing nations to hold together for the duration, however, while both multilateral and unilateral sanctions are viewed as targets of opportunity for the entrepreneurial trader.

Western governments should avoid the indiscriminate use of sanctions. The value of multilateral sanctions should be weighed against the value of engagement and dialogue. When the use of sanctions is deemed admissible in the support of international interests, governments should adopt a graduated approach and make every effort to ensure that the coverage of the sanctions is as targeted as possible. This should include a cost-benefit analysis of whether curtailing investment in, or revenue from, energy production will genuinely dissuade the target government from the specific behavior that provoked the imposition of sanctions.

Despite a limited success record, sanctions will continue to be used as a tool of foreign policy—as a means of rejecting the conduct of a particular nation—simply because there are no acceptable alternative courses of action. The world will have to live with the inherent limitations of the sanctions.

> Policy consideration: Avoid the indiscriminate use of sanctions. The value of multilateral sanctions should be weighed against the value of engagement and dialogue. When the use of sanctions is deemed admissible in the support of international interests, ensure that the coverage of sanctions is as targeted as possible. Unilateral sanctions are not an effective policy tool.

A similar contradiction exists in U.S. policy toward the Caspian region and Central Asia, where the United States is committed to reinforcing the newly independent states but where contrasting U.S. policies toward Iran, Turkey, and Russia are likely to influence, rightly or wrongly, the construction of commercially viable pipelines for the export of Caspian oil and gas. A policy approach that ties exports primarily to one pipeline route—with the goal of avoiding Iran and Russia as transit states—before the political and economic viability of that route is known may undercut the pace of energy development in the region, to the dismay of both producing states and potential transit states.

Oil and gas exports from the Caspian region and Central Asia hold the prospect of becoming a valuable additional source of energy supply. Even as the U.S. government works to make feasible an East-West transportation corridor that bypasses Russia and Iran, the United States should not obstruct the development of alternative routes that would ultimately offer exporters a diverse and economically attractive set of options for transporting oil and gas to foreign markets, especially those markets in Asia and the Far East.

Policy consideration: Do not obstruct the development of economic routes that would ultimately offer Caspian and Central Asian exporters a diverse set of options for transporting oil and gas to foreign markets.

Beyond these contradictions, if Western governments are to ensure adequacy of supply early in the twenty-first century, policies must be framed toward encouraging energy-producing countries to open their energy sectors to greater foreign investment. This would include provisions for the enforcement of contracts, guarantees for private property, anticorruption measures, and stable fiscal regimes. Increased private investment must occur as early as possible in exploration and production facilities and in transportation infrastructure, especially in Asia, if the world's energy supplies are to reach markets in sufficient quantities during the 2010–2020 period.

Policy consideration: Encourage energy-producing countries to ensure that their energy sectors attract and support greater foreign investment.

Given the continuing importance of a small group of energy-producing and -exporting countries to the future health of the global economy, it is vital that the United States and other Western governments place diplomatic relations, trade policies, and foreign assistance programs with each of these countries at or near the top of policy priorities.

It is in the self-interest of the United States and other Western governments to support China—rapidly emerging as a major oil importer—as it diversifies its sources of and forms of imported energy and encourage China to not rely excessively on the Persian Gulf. China is considering development of an infrastructure to support oil and gas imports from Russia and Central Asia and also for transit onward to other countries in the Far East. Collaborative cross-national energy infrastructure projects can play an important role in lessening the risks of future conflict over energy resources. However, such energy linkages may not always be in the best political interests of the United States.

Energy Reliability

In the early decades of the twenty-first century, because burgeoning energy demand must be met largely by a small number of oil and gas suppliers and because supply routes are lengthening, the risk posed by supply interruptions will be greater than it was at the end of the twentieth century.

Military conflict will remain a threat to most energy-producing regions, particularly in the Middle East where almost two-thirds of the world's oil resources are located. In addition, domestic turmoil within the key energy-producing countries constitutes another threat to reliability of energy supplies. At least 10 of the 14 top oil-exporting countries run the risk of domestic instability in the near to middle term.

The United States should retain as far as possible its ability to defend open access to energy supplies and international sea lanes. At a time when the administration faces myriad competing demands for military and peacekeeping interventions, this mission should be considered a strategic priority and may call for greater emphasis on, and increased investment in, appropriate military capabilities.

> Policy consideration: The United States should retain as far as possible its ability to defend open access to energy supplies and international sea lanes.

Some observers are concerned that the United States may seek relief from its self-imposed responsibility as the protector of the world's sea lanes, which are used for the transport of fuels and are becoming more crowded. U.S. allies in Europe and Asia should be prepared to shoulder a greater share of the financial cost of protecting energy supply, including sea-lane protection.

> Policy consideration: U.S. allies in Europe and Asia should be prepared to shoulder a greater share of the financial cost of protecting energy supply, including sea-lane protection.

No protector comparable with the U.S. role on the high seas exists for the increasingly important long-distance pipeline infrastructure. At a government-to-government level, international agreements to protect pipeline systems might have a deterrent effect. Governments must also find ways to work with the private sector to minimize the vulnerability of all energy infrastructures to sabotage or terrorist attack. Cyberterrorism may well pose the greatest threat during the time period under review.

> Policy consideration: Governments must find ways to work with the private sector to minimize the vulnerability of energy infrastructure to sabotage or terrorist attack, including cyberterrorism.

The more feasible approach in the near to medium term to mitigate the risks of gas-supply interruptions is to encourage importing countries to promote diversity among suppliers and delivery routes. European governments, particularly in view of their high dependence on Russian gas, should look closely at how security of gas supply might be enhanced.

To meet these challenges to reliable supply, importing nations must engage in contingency planning. The practice of holding government-financed strategic petroleum reserves is one essential method of limiting the impact of supply interruptions, provided that the stocks held are truly reserved for the intended purpose and not for manipulating domestic prices. Governments should maintain and, where appropriate, expand government-financed and -controlled strategic petroleum reserves. This could include extending the International Energy Agency (IEA) emergency preparedness program to nonmember countries that will become major oil importers and supporting the concept of regional stabilizing initiatives. For the foreseeable future, however, it would appear to be impractical and prohibitively expensive to hold strategic natural gas reserves.

> Policy consideration: Governments should maintain and, where appropriate, expand government-financed and -controlled strategic petroleum reserves, reserving their use for supply interruptions.

Energy and the Environment

Energy production and use have become linked to environmental concerns. Air pollution, oil spills, and their impact on habitats are among the many challenges confronting government and the energy industry.

However, the energy industry's primary source of international friction may revolve around the issue of global climate change, as amply demonstrated by the contentious debate over the cost and benefits of the Kyoto Protocol.

The United States is unlikely to ratify the Kyoto Protocol in its present form. Clearly, global climate change can potentially have major implications for the economies of the world. Continued research and understanding of the facts are imperative for progress on this issue.

By 2020, energy consumption by the developing countries of the world is expected to exceed energy consumption by the developed countries. This may hold particular implications for the environment. Technologies must be made available to help ensure that, for developing countries, the burning of fossil fuels releases minimal pollutants. Moreover, fuel choices must be broadened to include cost-competitive nuclear electric power.

There will be no easy solutions. Clean-coal technology stands beyond the economic reach of most developing countries. Switching from coal to natural gas will take time inasmuch as deliveries will be dependent on the availability of costly long-distance natural gas pipelines and liquefaction and regasification facilities for the export and import of liquefied natural gas.

> Policy consideration: Economically and environmentally sound technologies must be made available to help developing countries meet increasing energy demands.

Nuclear power is emissions free but poses its own set of competing policy concerns, ranging from reactor safety to waste disposal and nuclear weapons proliferation. Western governments should assess the conditions under which nuclear power could make a significant contribution to electricity supply in the developing world by first assessing those conditions under which nuclear power could make a continuing contribution to their own supply.

Developing country decisionmakers would have to ask themselves, "Is this the most sensible answer to our power problems, and is this option reasonably affordable?" Three essential criteria for a fourth-generation nuclear power reactor, suitable above all for use in developing countries, would have to be met.

- Modular construction, with a generating capacity of approximately 100 MW;

- Cost competitive compared with fossil-fuel generating plants; and
- Proliferation resistant.

Policy consideration: Western nations should assess the conditions under which nuclear power could make a significant contribution to electricity generation in the developing world.

A major challenge for the future is quite evident: how to produce, transport, and burn fossil fuels in massive amounts but in an environmentally friendly manner. Is that possible only through technological breakthrough? Because in democratic countries the regulation and deregulation process can involve lengthy legislative and executive interaction and a complex public vetting process, simply recommending that policymakers eliminate those regulations that inhibit bringing technological innovation to market is meaningless. Instead, Organization for Economic Cooperation and Development (OECD) governments should expand basic research leading to more efficient fuel use and to viable alternative fuels. At the same time, governments should fashion regulatory processes and standards that favor the market success of environmentally friendly innovative energy technology.

Countries should review the extent to which subsidies for domestic energy sectors are inconsistent with their global energy policies.

Policy consideration: OECD governments should expand basic research on energy technologies; concurrently, policymakers should eliminate those environmental regulations that inhibit bringing technological innovation to market. All governments should review the extent to which domestic energy subsidies are inconsistent with global energy policies.

Three Broad Conclusions

Three broad conclusions can be drawn from this analysis of geopolitics of energy into the twenty-first century.

- The United States, as the world's only superpower, must accept its special responsibilities for preserving worldwide energy supply.
- Developing an adequate and reliable energy supply to realize the promise of a globalized twenty-first century will require significant investments, and they must be made immediately.
- Decisionmakers face the special challenge of balancing the objectives of economic growth with concerns about the environment. This challenge has multiple parts: finding ways to increase security and reliability of supply; ensuring greater transparency in energy commerce; and strengthening the role of international institutions in matters of energy and the environment.

One of the ironies at the turn of the century is that, in an age when the pace of technological change is almost overwhelming, the world will remain dependent, during 2000–2020 at least, essentially on the same sources of energy—fossil fuels—

that prevailed in the twentieth century. Political risks attendant to energy availability are not expected to abate, and the challenge for policymakers is how to manage these risks.

What's New?

The influence of nongovernmental organizations (NGOs) on public and private energy-related policy decisions is perceived to be expanding.

Projected energy consumption in developing countries will begin to exceed that of developed countries, a change that will carry political, economic, and environmental considerations.

The spread of information technology and use of the Internet dramatically change the way business is conducted, and this change carries with it a new set of vulnerabilities.

The prospects of cyberterrorist attacks on energy infrastructure are very real; such attacks may be the greatest threat to supply during the years under review.

Global warming is attracting growing attention, and that attention will likely shape debate on future energy policies; it is hoped that debate will reflect sound science and factual analysis.

Security of Supply

If U.S. military power is committed to a limited but extended protection effort in Northeast Asia, the capacity to respond to a crisis like that of 1990 in the Persian Gulf will be severely limited. The United States will need to rebalance its security relations.

Policy Contradictions

The greater need for oil in the future is at odds with current sanctions on oil exporters Libya, Iraq, and Iran.

The United States deals with energy policy in domestic terms, not international terms; U.S. energy policy is therefore at odds with globalization.

226

Staff Report to the Federal Energy Regulatory Commission on Northwest Power Markets in November and December 2000

February 1, 2001

The analyses and conclusions are those of the study team and do not necessarily reflect the views of other staff members of the Federal Energy Regulatory Commission, any individual Commissioner, or the Commission itself.

825

Contents

Page

1. Overview and Summary 1

2. Background 4
   Generation Capacity and Ownership 4
   Northwest Energy Balance 8
   Historical Purchase and Trade Patterns 9

3. Northwest Markets During the Summer 2000 11
   Prices and Sales 11
   Sales and Revenue by Sector 13
   Generation and Input Costs 14
   Gas Cost Increases to Utility Plants 16
   Environmental Factors and Weather Conditions 16

4 Northwest Markets in November and December, 2000 18
   Spot Market Power Prices and Volumes 18
   Weather and Hydro Conditions 20
   Other Factors Contributing to High Prices and Spikes 23
   Combining the Factors: a Descriptive Statistical Analysis 27

Tables

1. Northwest Capacity Changes by Plant Type, 1991 to Present 6
2. Total Generation in the Region and the West, 1995 to 1999 7
3. Average Cost of Power Purchases by Utilities 1990 - 1999 9
4. Northwest Sales and Revenue, Totals for May through August, 1995 to 2000 14

Figures

1. Northwest Subregion of the WSCC 5
2. Generation Resource Capacity and Hydro Ownership in the Northwest 5
3. Northwest Capacity Surpluses and Deficits 1990 to 1999 8

4. Utility Wholesale Power Purchases in the Northwest 1990 to 1999 10
5. Mid Columbia and COB Prices, February to September 2000 12
6. Spot Market Natural Gas Prices 13
7. Total Power Generation by Resources in the Northwest, May to September 15
8. Power Generation from Natural Gas in the Northwest 15
9. Gas Costs at Western Electric Utilities, January to September 2000 16
10. Northwest Spot Gas and Electric Prices, November and December 2000 19
11. Price and Quantity at Mid Columbia for Day-Ahead On-Peak Power 20
12. Rank of Regional Temperatures 22
13. Rank of Regional Precipitation 22
14. Stream Flow Index for Washington State 23
15. California Emergencies: Hours in Emergency Status 24
16. NOx Reclaim Prices for SCAQMD 25
17. December 2000 Outages, California ISO 26

1. Overview and Summary

This report examines operating and market conditions in Northwest power markets during November and December 2000. It is an extension of an earlier report on bulk power markets in the West during summer 2000 and covers many of the same issues regarding high prices and their underlying causes. [1] The focus of this report is on rapidly increasing power prices during November and December, including a dramatic price spike in the second week of December. It provides further background on the Northwest in the context of the overall western power market described in the Western bulk power report, and examines the specific events and factors leading to increased prices during November and December.

The main observations from the study are summarized below:

- *November 2000 was the coldest November nationwide since 1911, with the coldest temperatures in the West and Northwest.* In early December, a massive arctic air mass descended on the Northwest region.

- *California was under frequent emergency conditions of varying severity during November and December, and was often unable to supply normal winter exports to the Northwest region*. The California emergency events are correlated with the high prices in the Northwest.

- *Low water levels, precipitation and stream flows limited the energy available from hydropower generation*. Especially low reservoir levels placed stringent limits on available water for power generation, in order to ensure supplies would be available later in the season during expected winter conditions. Low precipitation levels and diminishing stream flows in November and December led to lower forecasts of available water, and increased the impact on available water for power generation in December. As a result, the normal process of seasonal power exchange – sales from the Northwest to California in the summer in exchange for sales from the California to the Northwest in the winter – failed to materialize this year.

---

[1] *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, November 1, 2000.

- *Very little generation capacity was added in the Pacific Northwest (Washington and Oregon) or California during the 1990s* . This limited capacity, coupled with high demand and low energy supplies from hydropower, left the Northwest exposed to a power shortage when California experienced severe power emergencies. Additional generation is planned for the Northwest and California, but it is not projected to come on line until 2002 or 2003.

- *Environmental conditions limited the full use of power resources in the region* :

    - Air quality limits (on NOx) reached annual limits at a number of facilities in California and generation plants shut down, although some were later brought back on line after receiving waivers.

    - Minimum flow requirements at hydropower facilities needed to protect fish populations limited the ability to use water for power generation. Much of this water is "spilled" and not used for power generation. These limitations have a particularly large impact when reservoir levels and stream flows are low, by further reducing the water available for later generation needs.

- *Outages appear to have played a significant role in limiting availability of thermal capacity in the West* Scheduled outages were delayed this fall, in part out of concerns that high temperatures would continue through October. As a result, more plants were out on scheduled maintenance when the cold temperatures hit. Forced outages at thermal plants, including older gas plants running at higher levels from May through September and plants shut down because of NOx limitations, contributed to the overall level of outages as well. Outages in California were high during the critical period of price spikes in early December and certainly put pressure on other resources to meet demand. However, our data on outages are very limited outside California and firm conclusions are difficult to draw.

- *Natural gas price increases, limits on pipeline capacity and storage levels contributed to the pressure on power prices.* Natural gas price and availability were affected by similar demand conditions, including requirements for heating and for electricity generation. Contributing factors included pipelines to California running full at capacity or limits on the capacity to take gas from the pipeline into the distribution systems, flow orders on some pipelines resulting from the flow levels, and low levels in California combined with high storage withdrawal rates.

- *Statistical analysis of available data confirms that much of the variation in power prices can be explained by operating conditions.* For example, a regression analysis indicates that around 94 percent of the power price variation can be explained by temperature, precipitation or stream flow levels, and tight supply and demand measured by the prevalence of emergency conditions in California.

In summary, the northwest power markets saw increased demand through the 1990s, without increased generation capacity in either the Pacific Northwest or in California. In November and December of 2000, the market was driven by extreme cold, high natural gas prices and low storage levels, and by low water, precipitation and stream flow levels. These conditions were made worse by an operating environment with a large number of outages and environmental constraints, and the general atmosphere of market uncertainty surrounding the extreme nature of these fundamental factors. In this environment, power prices rose to extremely high levels for much of the period, levels above short-term power production costs, and, if sustained, above long-term costs as well.

Northwest customers are not as exposed to these high prices as those in California. In California, some customers were directly exposed to the high spot market prices (San Diego) while others found their utilities at risk because of high power purchase costs. In the Northwest, customers are at much lower risk from the high prices, because a much greater proportion of the northwest load is protected through utility-owned generation or long-term contract, but some impact on customer rates is to be expected.

Section 2 provides a background showing how the Northwest fits into the context of the general western power markets and differentiates the northwest conditions from the remainder of the West. Section 3 summarizes the conditions leading up to November and December, and Section 4 analyzes the events of November and December.

2. Background

For purposes of this report, the Northwest power market will be viewed as the Northwest power area (NWPA) a subregion of the Western Systems Coordinating Council.[2] This area is shown in Figure 1. The Northwest power market is distinguished from other regional markets by the dominant role of hydropower resources and by substantial presence of federal and other public power entities, as depicted in Figure 2. From a planning and operational perspective, the major role of hydropower means that energy availability plays a central role, with generation capacity requirements highly dependent on water resource conditions and water use requirements outside the energy sector. In all regions, electricity demand is sensitive to long and short-term weather conditions. In the Northwest, both demand and supply conditions are highly dependent on weather.

This section surveys the patterns of generation resource use, loads and ownership in the Northwest and west since 1990. During this period, very little capacity was added in the Northwest, while loads were growing and generation from the aging resource base was utilized at an increasing rate. Areas outside the Pacific region (Washington, Oregon and California) supplied an increasing proportion of the generation needs in the West. At the same time, non-utility generation assumed a larger role, as overall utility purchases more than doubled and purchases from non-utility sources increased substantially. The remainder of this section provides background material on the evolution of these factors in the 1990s, setting the stage for the developments of summer and fall 2000.

Generation Capacity and Ownership

The Northwest currently has approximately 55,000 MW of winter generating capacity, about 65 percent hydropower. Very little capacity has been added since 1990: additions of 3,300 MW of capacity have been reduced by 2,530 MW of retirements. Additions to capacity have been primarily natural gas, but these have been offset by the retirement of nuclear capacity (see Table 1). Overall, operating capacity has increased by only 2 percent over a 10-year period.

---

[2]Unless otherwise noted, only the U.S. portion of the area will be included. This area includes Washington, Oregon, Idaho and Utah, and portions of Montana, Wyoming, Nevada and California as shown in Figure 1.

Figure 1. Northwest Subregion of the WSCC

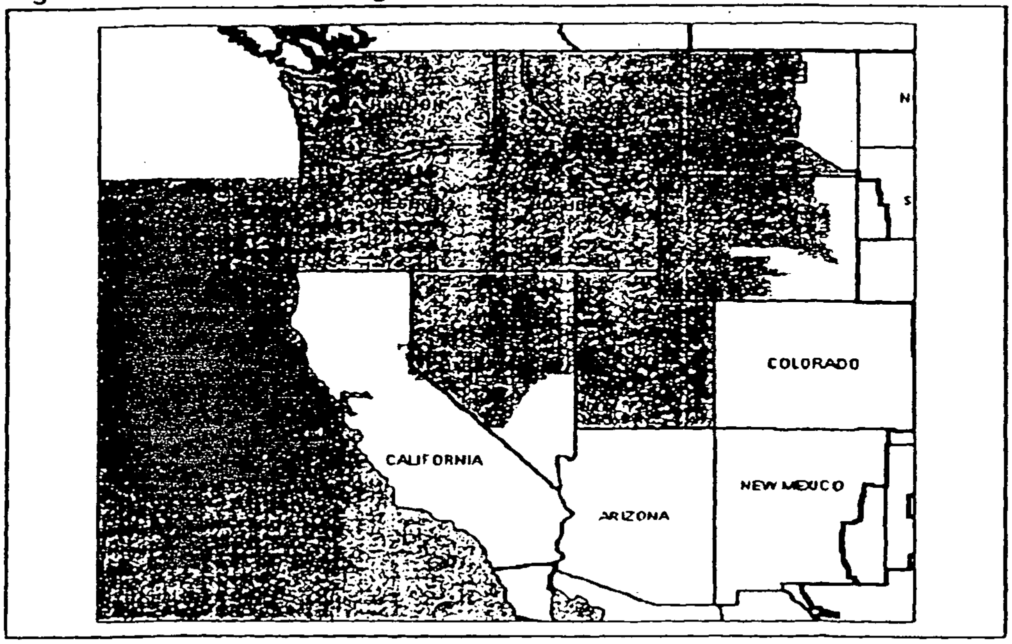
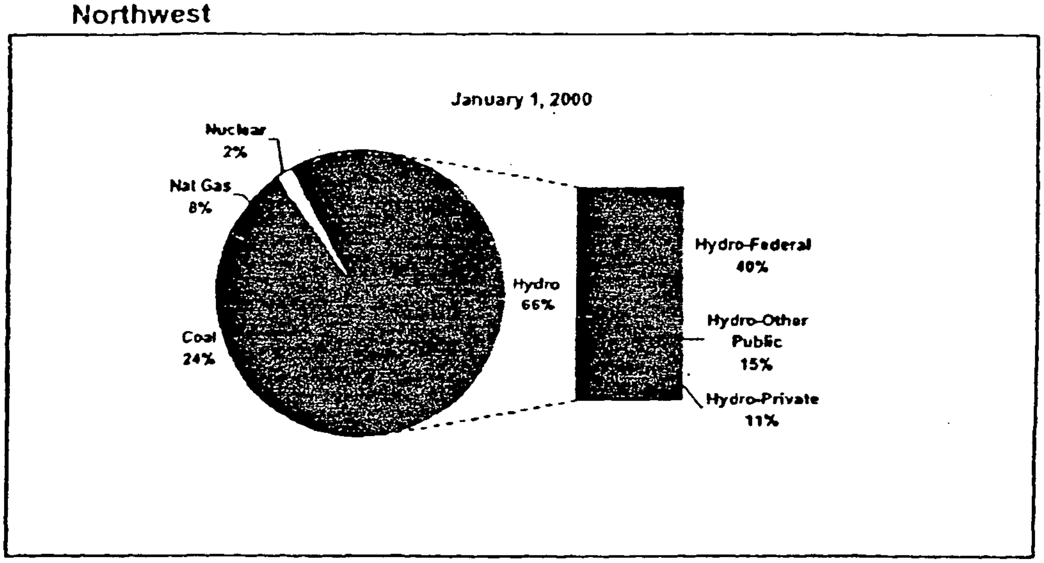


Figure 2. Generation Resource Capacity and Hydro Ownership in the Northwest



832

DOE002-0842

Table 1. Northwest Capacity Changes by Plant Type, 1991 to Present

Plant Type	1996-2000	1991-1995	Total 1991-2000	Current Capacity
	Capacity in Megawatts			
Additions to Operating Capacity				
Combine Cycle	1,091	962	2,053	2,587
Gas Turbine	69	447	516	1,155
Hydro	48	352	400	35,575
Nuclear			0	1,107
Steam	34	339	372	14,668
Total	1,241	2,100	3,341	55,091
Capacity Retirements				
Combine Cycle			0	2,587
Gas Turbine	240	59	299	1,155
Hydro	1	26	28	35,575
Nuclear		1,944	1,944	1,107
Steam	99	160	260	14,668
Total	340	2,190	2,530	55,091
Net Capacity Additions				
Combine Cycle	1,091	962	2,053	2,587
Gas Turbine	-171	388	217	1,155
Hydro	47	326	372	35,575
Nuclear	0	-1,944	-1,944	1,107
Steam	-66	178	113	14,668
Total	901	-90	811	55,091

Note: Internal combustion plants included in gas turbine category. Other plant categories not listed contributed 150 Megawatts of net capacity additions from 1991 to 2000.
Source: Resource Data International, PowerDat Database, January 2001.

The low rate of additions to capacity in the Northwest has corresponded to an equally low rate in California, changing the pattern of generation needed to meet demand in the Pacific Northwest (Washington and Oregon) region and California. [3] Resources in the Pacific region have been run more frequently and other areas of the West have increased their share of total western generation. Table 2 shows the growth of generation in the Pacific region and the overall west. As the table shows, generation in the Pacific region increased by 37 billion kilowatthours (BkWh) from 1995 to 1999, an 11% increase from a virtually unchanged resource base over the period.

[3] California, Oregon and Washington make up the Pacific census region, and will be referred to as the "Pacific region."

Table 2 shows a shift in generation away from resources in the Pacific to other areas of the west. From 1995 to 1999, generation in the West outside the Pacific region grew by 58 BkWh, or 22 percent. This rate of generation increase was twice the rate in the Pacific region. Although increases in demand outside the Pacific account for some of this increase, the increased generation also substituted for the lack of additional capacity in the Pacific region.

Table 2. Total Generation in the Pacific Region and the West, 1995 to 1999
(Million Kilowatthours)

	1995	1996	1997	1998	1999
			Utility Generation		
Washington	95,671	112,606	117,453	97,128	112,072
Oregon	44,031	47,884	49,068	46,351	51,698
California	121,881	114,706	112,183	114,928	87,875
Pacific Region Total	261,583	275,196	278,704	258,407	251,645
Rest of the US West	258,329	266,925	281,928	307,433	296,479
Pacific as % Total West	50.3	50.8	49.7	45.7	45.9
			Non-Utility Generation		
Washington	6,703	6,216	4,859	5,203	5,181
Oregon	1,321	3,239	3,446	4,921	5,126
California	63,935	63,484	62,422	76,021	108,228
Pacific Coast Total	71,959	72,939	70,727	86,145	118,535
Rest of the US West	12,263	13,480	13,744	13,689	32,475
Pacific as % of Total West	85.4	84.4	83.7	86.3	78.5
			Total Generation		
Washington	102,374	118,822	122,312	102,331	117,253
Oregon	45,352	51,123	52,514	51,272	56,824
California	185,816	178,190	174,605	190,949	196,103
Pacific Coast Total	333,542	348,135	349,431	344,552	370,180
Rest of the US West	270,592	280,405	295,672	321,122	328,954
Pacific as % of Total West	55.2	55.4	54.2	51.8	52.9

Source: Resource Data International, PowerDat Database, January, 2001.

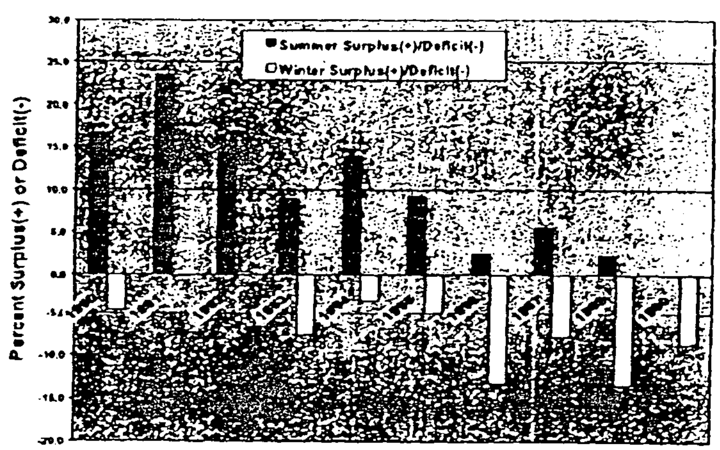
Table 2 also shows the shift in ownership of generation from utilities to non-utilities. Most of the increased non-utility share in the Pacific has been in California. California has historically taken a large share of its power from non-utility sources, but the proportion increases dramatically in 1998 and 1999 from around 63 BkWh (1995 to 1997) to 108 BkWh in 1999, in large part a result of selling off utility generation capacity. States in the Northwest have not undertaken a program of retail access or divestiture of utility assets comparable to California. The Northwest has seen much more modest shifts toward non-utility sources: Washington decreased over the 5-year period, with only around 5 percent of generation from non-utility sources, while Oregon increased significantly from a small base in 1995 to around 9 percent in 1999.

Northwest Energy Balance

The Northwest is a winter-peaking region. Typically, it provides power to California and other southern areas of the west in the summer and receives power from these areas during the winter. Thus, the Northwest has surplus power needs that it markets to the south in the summer, but runs a deficit in the winter during its peak winter period. Although the Northwest has a power deficit during the winter, the Northwest is generally less dependent on outside resources to meet load than California, in part because of the historically abundant sources of hydropower. However, water for generation may also be needed to preserve water or maintain stream flows for other water uses or for environmental mitigation. During a low water year, the Northwest will have less surplus power for other regions during the summer and greater needs for power from those regions during the winter.

Since 1990, the Northwest's dependence on resources outside the region has increased, as the summer surplus of capacity over peak load has diminished and the winter capacity deficit has widened. This trend is shown annually in Figure 3. This figure shows the winter and summer peak loads in the Northwest and the corresponding

Figure 3. Northwest Capacity Surpluses and Deficits 1990 to 1999



Source: Resource Data International, PowerDat Database, January, 2001.

835

DOE002-0845

generation capability. Although some year-to-year variation is to be expected, due to variation both in energy demand and in energy supply limitations on hydro resources, the trend is clearly downward, reflecting the increasing need to rely on power generated outside the area.

Historical Purchase and Trade Patterns

Western utilities actively traded wholesale electric power before the advent of restructuring. Although transmission constraints can limit trade at times, these constraints are not generally binding and power can be freely traded at most times. The average rates for wholesale purchases by utilities are shown in Table 3. Over the 10-year period of the 1990s, rates are seen to increase and to come closer together. When wholesale trading was smaller in scope than today, and cost based, low prices frequently reflected surplus conditions and prices in one area could be low while they were high in another. As trade has moved to market-based pricing in recent years, the spread of prices has narrowed. In 1999, for example, the spread in the average purchase cost per MWh across the Arizona, Northwest and Rockies regions was only $4/MWh; in 1990 it was $18 and in 1995 it was $10.

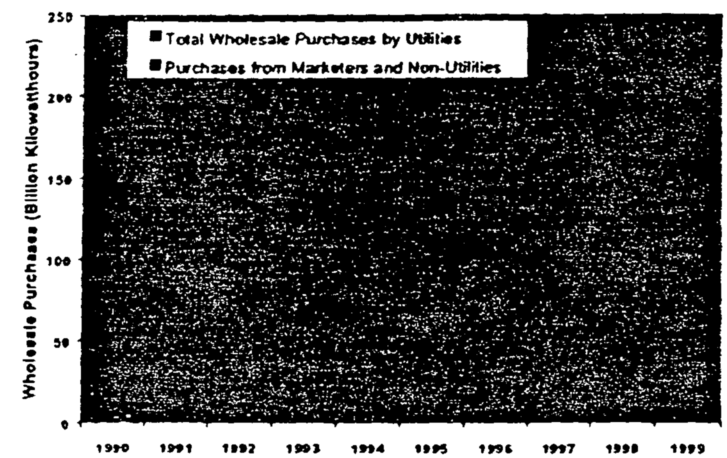
The convergence of prices outside California has been accompanied by dramatic increases in volumes purchased. These volumes reflect both increased reliance on trade for supplying loads, but also increased wholesale activity on the part of the utilities themselves. Both the level of trade and proportion of purchases from marketers and non-utilities have increased dramatically, as shown for the Northwest in Figure 4.

Table 3. Average Cost of Power Purchases by Utilities 1990 - 1999 ($/MWh)

	WSCC Subregion				
Year	Arizona	California	Northwest	Rockies	Total
1990	$38	$53	$20	$28	$38
1991	$36	$52	$20	$30	$37
1992	$38	$57	$22	$32	$40
1993	$36	$58	$25	$31	$41
1994	$37	$61	$27	$36	$42
1995	$35	$57	$25	$35	$40
1996	$32	$54	$29	$34	$36
1997	$31	$50	$24	$35	$33
1998	$30	$55	$29	$36	$36
1999	$27	$45	$31	$30	$35

Source: Resource Data International, PowerDat Database, January, 2001.

Figure 4. Utility Wholesale Power Purchases in the Northwest 1990 to 1999



Source: Resource Data International, PowerDat Database, January, 2001.

3. Northwest Markets During the Summer 2000

The high prices and the power crisis in California were the main focus of attention in the summer of 2000, but the underlying problems were wider regional ones, and the Northwest felt the impact as well. Residential and small commercial customers were not directly exposed to short-term market prices, as they were in San Diego. As Table 2 above shows, most of the generation in the Northwest is utility-owned, and the impact of the high prices in the spot market is lessened by the relatively small proportion of the overall market exposed to those prices. Nevertheless, the recent increases in price have been large and sustained, and the degree of dependence on external supplies or the spot market varies by individual utility. This section provides a general description of how the western market over the summer affected conditions in the Northwest, and provides some limited information on the likely, eventual impact of those prices on customers.

Prices and Sales

Spot Market Price Patterns

Although power market prices spiked at certain points over the summer, the recurrence of high prices over the longer term may have a greater impact on customer bills. Prices spiked less frequently as the summer progressed and California imposed price caps at lower levels, but average prices continued to climb. This climb in prices can be observed in the spot prices at the California-Oregon Border (COB) and at receipt points along the Columbia river (Mid-C) by averaging the daily prices over the previous 30-day period and plotting the trend as shown in Figure 5. A large, but short-lived spike in prices will appear as a jump in the 30-day average, followed by a gradual reduction in the average price. Figure 5 shows a very different pattern: average prices jump up, but they stay at the higher level until the middle of September.

Natural Gas Spot Prices

The cost of natural gas as an input to power generation is one factor in the rising power price. For much of this period, natural gas was the marginal fuel for power generation, at least in California. So it is reasonable to assume that the rising trend in power prices was driven in part by a corresponding rise in gas prices at western delivery points. Figure 6 show the gas prices corresponding to the power prices in Figure 5. The price pattern seems to have four distinct stages:

(1) A moderate rise from around $2.50 per MMBtu from the beginning of the year to about $3.00 per MMBtu in late May;

(2) A more rapid rise to the $4.00 level at the end of June, corresponding to the initial stages of the problem in California;

(3) A leveling off at $4.00 in July and early August, corresponding to moderating weather and load conditions in July; and

(4) A return to the rapidly rising trend in late August and September, to a level over $5.00 by the end of September.

Unlike power prices, spot natural gas prices gave no indication of a falling trend at the end of September. While there seems to be a relationship between gas and power prices in spot markets, it is clearly not simple and direct. Prices for both increase over the period, but at very different rates: gas moves from around $2.50 in May to over $5.00 in September, approximately doubling. Over the same period, power prices moved from around $25 in May to $150 to $200 in September, a six- to eight-fold increase.

Figure 5. Mid Columbia and COB Prices, February to September 2000

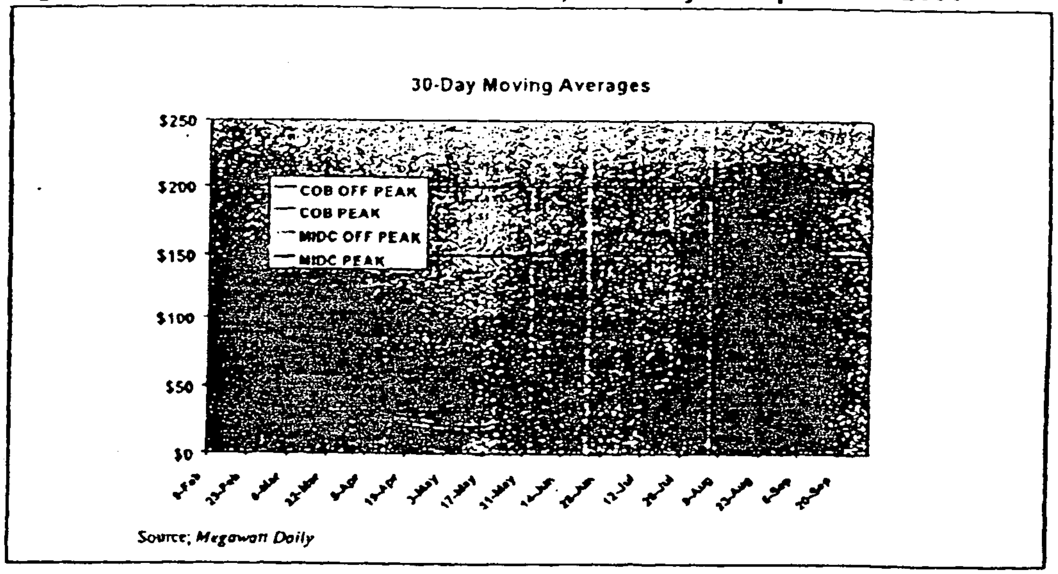
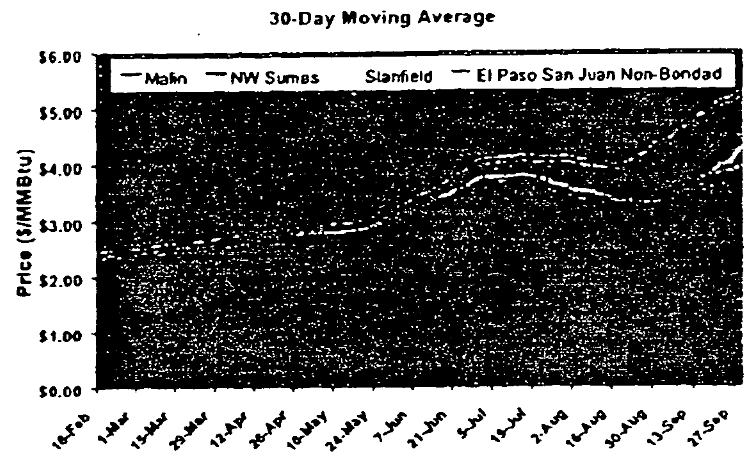


Figure 6. Spot Market Natural Gas Prices



Source: *Gas Daily*

Sales and Revenue by Sector

Preliminary sales and revenue data for the summer do not yet show an indication of rising prices to consumer in residential and commercial sectors. As shown in Table 4, residential sales in the period of May through August have grown from 1995 to 2000, increasing 20 percent over the period; prices grew 6 percent from 1999 to 2000, but this growth does not appear to be significantly higher than in previous years. Industrial sales, on the other hand, have been flat over the period, with year 2000 sales increasing less than 1 percent over 1995.

Residential and commercial power revenues per MWh increased only 1 percent in 2000 over 1999. However, there have been several reports of requests for rate increases by utilities, so there will be some longer term rate impact. [4]

Some indication of potential rate increases may be reflected in increases in industrial prices, which are more likely to quickly reflect pass-through of changes in

[4]The Eugene Water and Electric Board received an increase of 15 percent. Seattle City Light has had two 6-percent rate increases and a 10-percent surcharge.

Table 4. Northwest Sales and Revenue, Totals for May through August, 1995 to 2000

	1995	1996	1997	1998	1999	2000
Residential and Commercial Sectors						
Sales	25.6	27.4	25.8	28.0	29.1	30.9
Average Revenue/Mwh	$56	$58	$58	$58	$57	$58
Industrial Sector						
Sales	22.7	20.5	21.4	23.7	23.1	22.8
Average Revenue/Mwh	$32	$32	$29	$28	$29	$34

costs to the utility than are rates for residential and commercial customers. Industrial average revenues for May through August of 2000 show increases of 20 percent over May through August of 1999 for the Northwest as a whole. Increases varied considerably by state and utility over the summer. In the month of August, for example, the increases in 2000 over August 1999 were largest in Washington (34%) and Oregon (24%), while the remainder of the West had increases of only 4 percent. One utility, Puget Sound, had an increase of 158 percent, from $33/MWh to $84/MWh, and others had increases in the 30% to 50% range. [5]

Generation and Input Costs

Northwest Generation by Resource

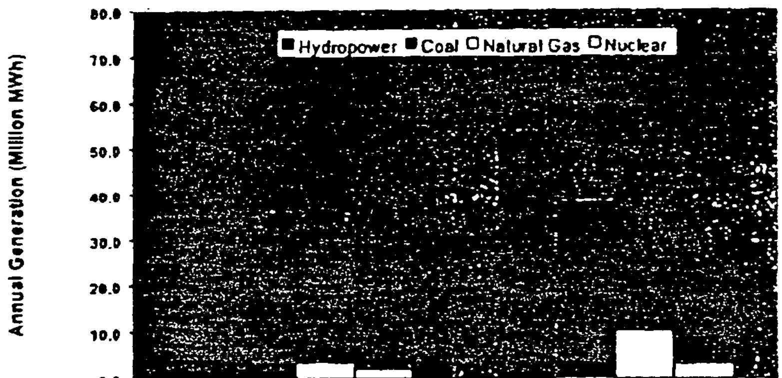
The summer period, May through September, shows two main changes from the pattern of generation in prior years: lower hydropower generation and higher natural gas generation. Hydro generation fell 13.3 million MWh, a decrease of 20 percent from the average of the previous 5 years (see Figure 7.) The loss of hydropower generation was made up by a three-fold increase in natural gas generation (from 3.3 to 10.2 million MWh) and increases in other steam generation from coal and nuclear power plants.

The increase in gas use is a significant increase over prior years, but the trend has been consistently upward, as shown in Figure 8. Some of the increase reflects the addition of new combined cycle capacity, but it also may reflect increased use of older gas steam facilities. Coupled with the increases in gas use elsewhere in the west over the summer, it reflects a new level of gas use in electric generation that can have a significant impact on gas usage if it coincides with peak gas use periods in the winter.

---

[5]Source: RDI PowerDat Database, January 2001. Information based on a sample of utilities in each state.

Figure 7. Total Power Generation by Resources in the Northwest, May to September



	Average, 1995-1999	2000
Hydropower	67.0	53.7
Coal	35.8	30.2
Natural Gas	3.3	10.2
Nuclear	1.9	3.1

Source: Resource Data International, PowerDat Database, January, 2001.

Figure 8. Power Generation from Natural Gas in the Northwest

	1995	1996	1997	1998	1999	2000
Natural Gas	2.6	2.7	2.6	3.6	5.0	10.2

Source: Resource Data International, PowerDat Database, January, 2001.

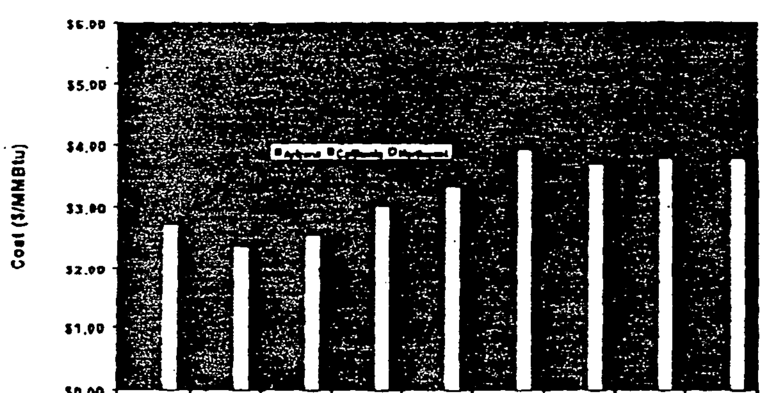
Gas Cost Increases to Utility Plants

The increases in gas use over the summer coincided with the increase in the spot market price of gas. The increases in the spot market price reported in the trade press can be compared with actual gas costs reported at electric utility plants. The gas cost at electric plants in the West is shown in Figure 9. Northwest gas costs increased less than costs in other western regions, starting out the summer near the spot market levels of around $3.00/MMBtu, and ending the summer under $4.00/MMBtu when the spot market price went above $5.

Environmental Factors and Weather Conditions

The Northwest was not directly impacted by the high environmental costs of power generation that raised generation costs in southern California. Since power price increases in one region of the West rapidly translate into increases throughout the West, however, these factors are likely to have had significant indirect impact by raising market prices for power throughout the west.

Figure 9. Gas Costs at Western Electric Utilities, January to September 2000



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Arizona	$2.49	$2.77	$2.93	$2.93	$3.43	$4.45	$4.44	$4.40	$4.45
California	$2.94	$3.09	$3.07	$3.14	$3.70	$4.92	$5.02	$5.13	$5.13
Northwest	$2.72	$2.37	$2.55	$3.01	$3.32	$3.91	$3.67	$3.78	$3.78

Source: Resource Data International, PowerDat, January, 2001.

843

DOE002-0853

The most direct environmental impact in the Northwest is on the availability of water for hydropower generation. The largest impact appears to have resulted from the pattern of runoff during the spring.[6] Over the summer months, Northwest stream flow conditions appear to have been near normal.

Weather conditions in the Northwest during the summer were not as extreme as in other areas of the West. May, June and August were well above normal, but July was near normal. These conditions would not tax the power system in the Northwest under normal conditions, since the summer is not the peak season in the region. However, when combined with the hydropower conditions, they did serve to limit the ability of the Northwest to supply power to California and the Southwest.

[6]See Bulk Power Report, Vol 1, p 2-24.

4. Northwest Markets in November and December, 2000

This section describes the recurrence of high prices and price spikes in the Northwest in November and December 2000, and then discusses the fundamental factors contributing to those spikes. It concludes with a short statistical analysis that quantifies some of the leading factors and uses them to estimate the pattern of power prices in November and December.

Spot Market Power Prices and Volumes

In September and October, power prices appeared to be moderating from the sustained high levels of the summer. Prices continued to fluctuate considerably, but the trend was clearly downward from late August prices over $200 ($225 at Mid-Columbia on August 29) to prices under $100 in early November ($75 on November 4.) In mid-November, prices for natural gas and electricity started to rise again (see Figure 10.) The increases at first were small enough to be attributed solely to anticipation of the winter peak season, but then gas prices jumped over $10 per MMBtu and electricity prices rose to over $200. This significant trend was punctuated by dramatic increases in early December, but returned after the spikes subsided to close around $300 during the last week of December.

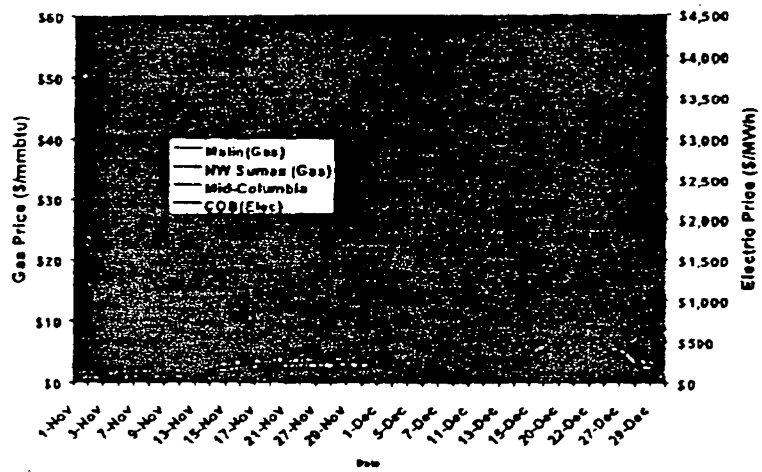
The December prices were foreshadowed by the balance of the month prices at the beginning of December. Balance of the month trades of $310 for December were reported at Mid-Columbia, while prices of $245 at NP15 and $189 at Palo Verde were reported.[7] The higher prices at Mid-Columbia underscore the market perception that the Northwest was likely to be the area of greatest power needs during December. This pattern is reinforced by a comparison with December forward prices a few days earlier: $220 at Mid-Columbia, $190 at NP15, and $180 at Palo Verde.[8] Not only do these prices show the rapid increase in forward prices for December, they also show that the Northwest led the increase, with Mid-Columbia up $90, while NP15 rose only $55 and Palo Verde only $9. Clearly, there were anticipated problems in getting power to the Northwest in December.

---

[7] *Megawatt Daily*, December 1, 2000.

[8] *Megawatt Daily*, November 27, 2000.

Figure 10. Northwest Spot Gas and Electric Prices, November and December 2000



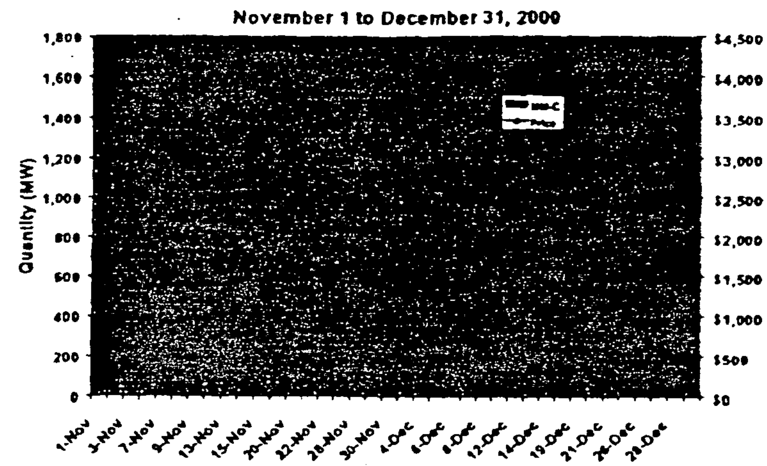
Source: *Megawatt Daily, Gas Daily*

The pattern of natural gas prices tracked with the pattern of power prices (see Figure 10). Power prices did not follow the rapid run up in natural gas prices in the last week of November, but otherwise shifts in power prices appear to mirror shifts in natural gas prices. The last week in November set the stage for the natural gas price increases: the natural gas price at Sumas, Washington, started the week at $8.50 on November 20 and doubled to $17.04 in two days, just before the Thanksgiving holiday. Frigid weather, pipeline operational flow orders (OFOs) on several regional pipelines (Northwest, PG&E, Transwestern and El Paso) and the "dire status" of Southern California gas storage conditions were all cited in trade press accounts as key contributing factors in the rapid gas rise.[9] The speed and size of the natural gas price increase appeared to take the market by surprise, and no immediate impact was seen in power prices.

The power price spikes came in early December, when prices began to rise in the week beginning Monday, December 4. At the end of the week, on December 8, prices for the following Monday, December 11, jumped to over $4,000 at Mid-Columbia and to

[9] *Natural Gas Intelligence, Gas Price Report*, November 27, 2000.

Figure 11. Price and Quantity at Mid Columbia, Day-Ahead On-Peak Power



Source: *Megawatt Daily*

$3,000 at the California-Oregon border. The factors contributing to the rising trend and the price spikes are discussed in the remainder of this section.

Although prices spiked to extraordinary levels on December 11 and 12, as shown in Figure 10, it is not clear how much power was purchased at these prices, and we lack available information to determine the degree of exposure of utilities and their customers in the Northwest. Based on the volumes reported in *Megawatt Daily*, however, it does appear that overall quantities bought diminished as prices spiked (see Figure 11.) The quantities reported in *Megawatt Daily* do not represent estimates of total market quantities, but only the actual quantities included in the price survey. If changes in these quantities are representative of general changes in the market, they do show a marked reduction in purchase quantities beginning in the first week of December when the market began to founder and prices started their path to extreme values.

Weather and Hydro Conditions

As noted in the last section, Northwest weather and climatic factors, specifically temperatures and stream flow conditions, did not appear to be critical factors over the summer or during the early fall. But temperature, precipitation and stream flow conditions changed for the worse during November and early December.

Figure 12 shows the monthly temperature rankings from September to December in three western regions, showing that the entire west experienced an extremely cold November. Nationwide, November was reported as the second coldest November of the 106 on record, with only the winter of 1911 being colder. Idaho, Wyoming, Utah and Arizona experienced their second coldest winters on record, and California and Colorado their third coldest.[10]

Figure 12 shows general temperature conditions, but doesn't show how closely related concerns about weather during the week of December 11 were in early December when prices started to rise. Forecasts during the first week of December anticipated a "polar pig" arriving the next week and bringing record-breaking temperatures for the entire west. The frigid temperatures were forecast to last the entire week [11]. These forecasts combined with a series of Stage 2 emergencies at the California ISO, fueled the trading on Friday, December 7, when prices for power delivered on Monday, December 11, rose to $4,000 at Mid-Columbia. During the week beginning Monday, December 11, the extreme cold arrived, but the extreme conditions did not last quite as long as predicted, with a moderating trend through the week. Prices subsided as temperatures moderated.

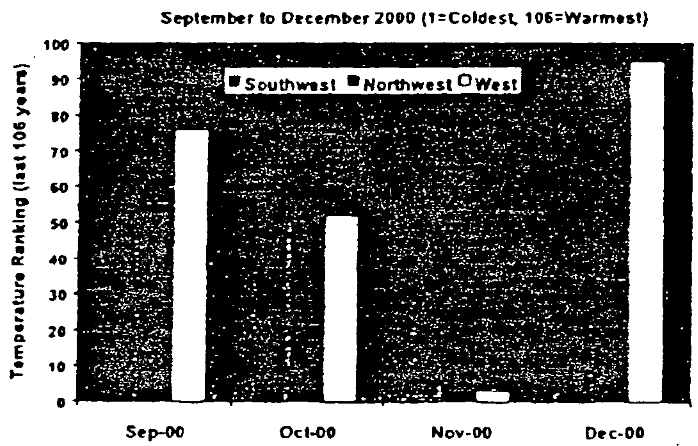
Extreme cold was not the only weather-related factor in the power shortages and high prices. Precipitation in the Northwest, which had been at least at normal levels in September and October, fell to low levels in November and December (see Figure 13) raising growing concerns about the available hydropower at the normal peak winter period in January or February. The precipitation conditions were accompanied by a significant shift in stream flow conditions from normal to low levels through November. The Figure 14 shows how the average stream flow index for Washington fell rapidly until mid-December, reinforcing other demand and supply conditions leading up to the December price spikes.

---

[10] *Natural Gas Intelligence*, December 11, 2000, based on reported information from Salomon Smith Barney.

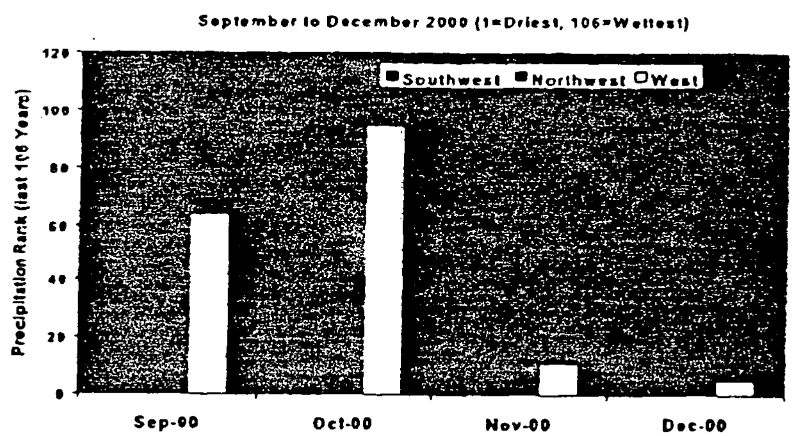
[11] Salomon Smith Barney meteorologists Jon B. Davis and Mark Russo, quoted in *Natural Gas Intelligence*, December 11, 2000.

Figure 12. Rank of Regional Temperatures



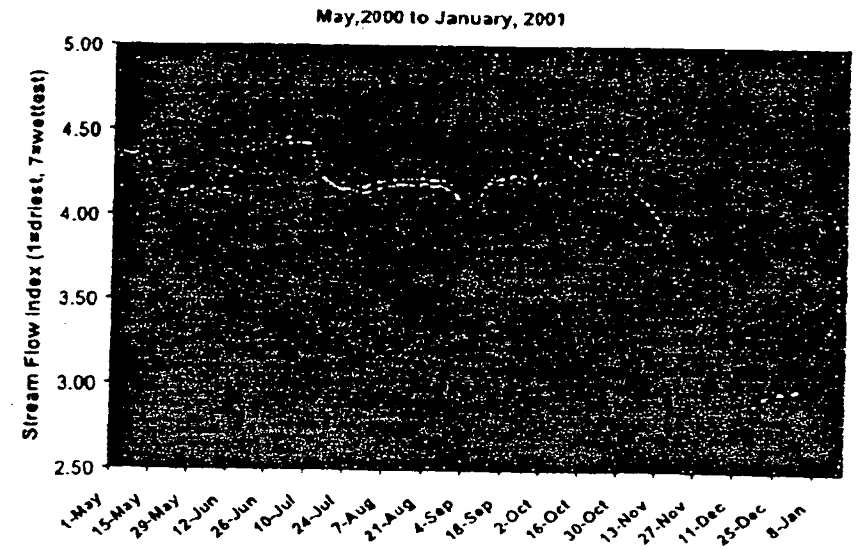
Source: NOAA website, www.ncdc.noaa.gov/ol/climate/research/caq3/caq3.html

Figure 13. Rank of Regional Precipitation



Source: NOAA website, www.ncdc.noaa.gov/ol/climate/research/caq3

Figure 14. Stream Flow Index for Washington State

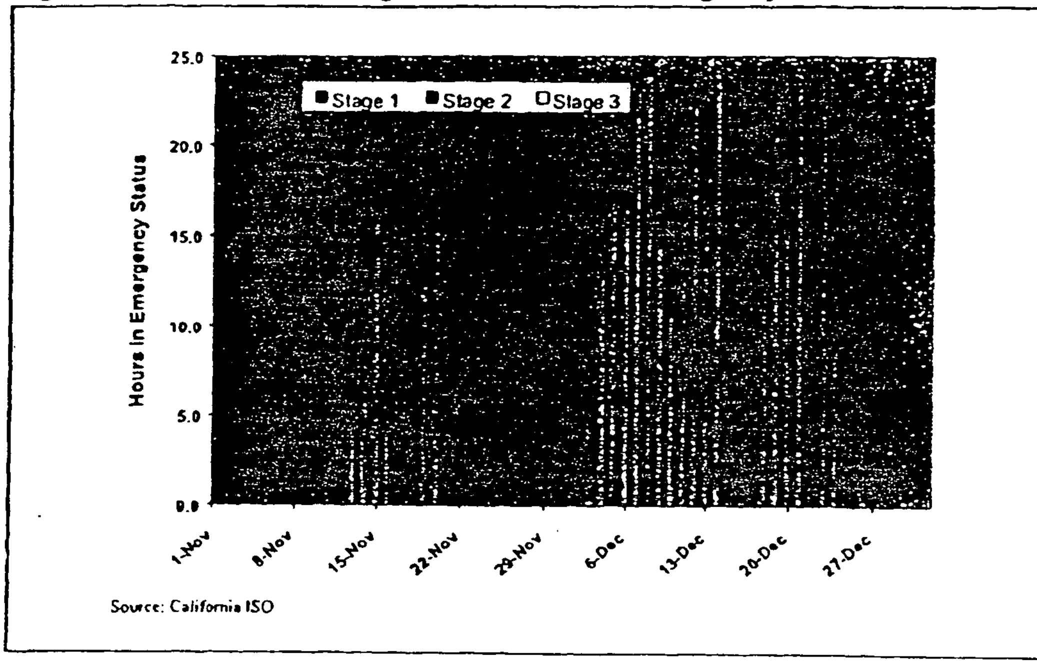


Source: USGS web site: water.usgs.gov/cgi-bin/average_daily?wa

Other Factors Contributing to High Prices and Price Spikes

Several other key factors contributed to the power shortage and price events. There were no emergency conditions at the California ISO in October, permitting power prices to moderate somewhat. As power shortage concerns deepened in December, California experienced a return of emergency conditions. These conditions show up clearly in Figure 15, which plots the hours under each of the emergency stages for the days in November and December. The emergencies were a result of worsening supply and demand conditions, but they fed back into the market, creating additional market stress about the ability to find supplies to meet demand and making the market aware of the vulnerable status of the California ISO.

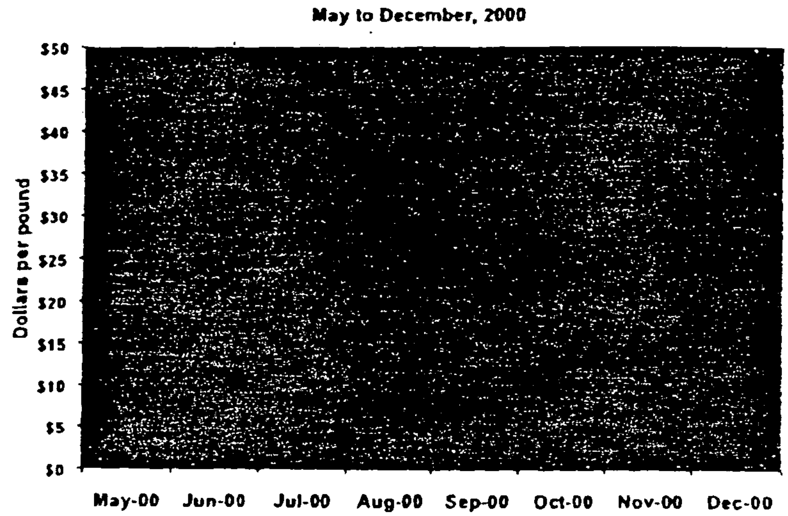
Figure 15. California Emergencies: Hours in Emergency Status



Environmental factors continued to exert further stress during the period. For natural gas supply, they affected both price and quantity. First, prices for NOx permits continued at high levels (see Figure 16) in Southern California. The rules governing the use of these permits make it difficult to directly estimate the impact of their prices on generation costs, but prices at the levels seen since August 2000 are bound to exert upward cost pressure on prices in Southern California and influence power prices in the west when gas is on the margin. Given the conditions in California, gas could be expected to be on the margin much of the time. The impact can be particularly pronounced under emergency conditions, when older units with very high NOx emissions rates are needed to meet load.

Second, environmental restrictions could prohibit certain plants from running at any price. When plants are subject to hard limits on output of NOx emissions, special waivers are needed to permit the plants to run. The need to obtain permits, and the negotiated outcomes that arise, make the environmental component of power pricing an even more uncertain exercise than it is under more normal conditions. This condition occurred during critical times in November and December: 2000 MW of AES gas-fired capacity were taken offline at the end of November under regulatory pressure to install

Figure 16. NOx Reclaim Prices for SCAQMD



Source: Cantor-Fitzgerald web site.

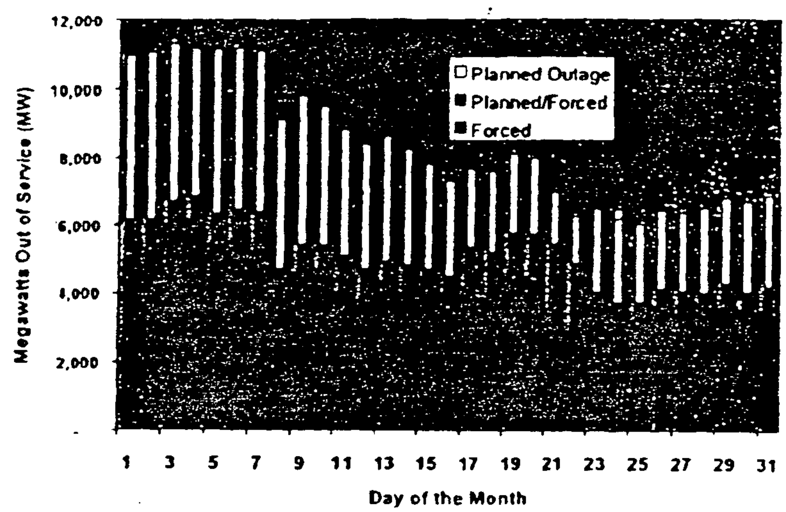
scrubbers. This capacity was returned to service after the high prices on December 11, when AES reached an agreement with the South Coast Air Quality Management District that eased penalties and permitted the capacity to return.

Finally, there are environmental requirements to maintain flow levels for the protection of fish populations which limit the use of water for power generation. As stream flows diminish, the need to release a certain amount of water to preserve the environment will have a major impact on the available energy from hydropower in the Northwest. The water level behind Grand Coolee Dam in the Northwest is the second lowest of the last 25 years, approaching the level in 1989, a level far below all other years from 1975 to date.[12]

Outages were commonly cited by the California ISO as a contributing factor in California emergencies, and appear to have been important in other geographic areas as well. The only systematic outage data available for this study were from the California ISO for December. These data show that outages were high during the first week in December, but were lower in the remainder of the month (see Figure 17.) The specific relationship between these outages and power shortages and prices cannot be determined

[12]Assessing the 2001 Outlook, Northwest Power Planning Council

Figure 17. December 2000 Outages, California ISO



Source: California ISO.

from these data. The high level of outages during the week of December 4 to 10 probably contributed additional market stress as prices began to rise, and the lower level during the week of December 11 to 18 probably contributed to the relatively swift fall of prices from the highest levels. It is difficult to draw any further conclusions from these data, and no conclusions can be systematically extended to the Northwest.

Although we lack detailed quantitative information outside California, it appears, from trade press reports, that some scheduled maintenance was delayed from October to November out of concerns that high temperatures would last through October. [13] The normal winter period is January, so a large amount of planned maintenance was still being performed in December. These conditions are consistent with the level of planned maintenance shown in the California ISO data in Figure 17. In addition, three large nuclear units were out of service for scheduled maintenance at the same time in November. One of them, Diablo Canyon-1 was delayed for two weeks, finally returning around November 22. None of these conditions is inherently suggestive of a pattern of withholding. Even when specific requests to delay maintenance were granted, the results could be mixed. Maintenance on Diablo Canyon-2, scheduled for 4 days at the beginning of December, was delayed until the second weekend in December, from

[13] *Power Markets Week*, November 20, 2000.

December 9th to 11th. As a result the unit went down for maintenance, just as the power price for Monday, December was spiking to $4000 at Mid-Columbia. The unit came back into service late in the day on Monday, in time to contribute to moderating prices during the week, but too late to help mitigate the dramatic spike on Monday.

Combining the Factors: a Descriptive Statistical Analysis

Several of the factors discussed in this section were quantified and developed as a daily time series of prices and conditions. The time series was then used to quantify the relationship between power prices and these factors. The following factors were used in a statistical analysis of on-peak, day-ahead power prices reported in *Megawatt Daily* for the Mid-Columbia delivery point:

- *Temperature Conditions in the Northwest* . The temperature in Seattle as reported by the Accuweather.
- *Emergency Conditions in California* . For this purpose, the presence of emergency conditions was measured by the number of minutes in Stage 2 emergency each day, using data from the California ISO.
- *Stream Flow Conditions* . This measure used daily stream flow information for Washington. Two separate measures were constructed: an average index for each day across all streams, and a percentage of streams with flows below the 25th percentile.

These operating variables were used in a regression analysis to explain the price of power at Mid-Columbia. Using a statistical measure know as the coefficient of determination, or R^2, these variables are highly significant and explain 94 percent of the variation in the Mid-Columbia power price. This result confirms the belief that these fundamental operating conditions were important in explaining the price of power.

DRAFT 2/9/01

Preliminary Summer 2001 Reliability Assessment

INTRODUCTION

The purpose of this report is to provide a preliminary assessment of the Nation's electricity supply and delivery systems this summer.

The North American Electric Reliability Council (NERC), formed in 1968, is responsible for ensuring the reliability of the North American bulk power system. NERC works with all segments of the electric power industry and relies on a system of voluntary efforts and "peer pressure" to ensure compliance with its reliability standards. NERC is comprised of ten regional reliability councils encompassing virtually all of the continental United States, Canada, and the northern portion of Baja California Norte.

NERC defines the reliability of the interconnected bulk power system in terms of two basic, functional aspects:

> *Adequacy* — The ability of the electric system to supply the demand and energy requirements of customers at all times.
>
> *Security* — The ability of the electric system to withstand sudden disturbances such as unanticipated loss of system elements (e.g., generating units, transmission lines, etc.)

Generally speaking, adequacy refers to the amount of generating capacity available to meet system loads, while security encompasses to the day-to-day operation of the power grid.

Each year, NERC produces three reliability assessments: a ten-year reliability assessment which focuses primarily on the overall adequacy of generating and transmission resources, and two seasonal assessments (Summer and Winter) which provide much more detailed information regarding the state of the power grid for the upcoming season. NERC is now just beginning its Summer 2001 Assessment, which will be released in May 2001. Much of the data in this memo is taken from NERC's most recent ten-year assessment (released in October, 2000). As such, this information should be considered preliminary and subject to change as summer approaches.

This report looks at electric reliability primarily as a function of adequacy. However, security concerns are discussed where they have been identified. Assessments of the adequacy of electricity generating supplies typically compare peak demand and the generating capacity available to meet peak demand. The difference between capacity and peak demand is the capacity margin (measured as a percent of total capacity). We first look at capacity margins at the national level then regional levels, and progress down to specific regions of concern.

NATIONAL OUTLOOK

HISTORICAL CAPACITY AND DEMAND[1]

- Figure 1 shows total capacity, summer peak demand, and capacity margins for the U.S. over the past decade. Since 1990, summer capacity margins have fallen from 22% to just under 15% in 2000.

- From 1990 to 1999, peak demand has grown, on average, 2.5% per year, while total generating capacity has grown an average of 0.8% per year. Between 1989 and 1998, U.S. transmission capacity, as measured by transmission miles per MW of peak demand, decreased by 16.2 percent.

- According to the North American Electric Reliability Council (NERC), peak load for Summer, 2000 was just under 686,000 megawatts (MW), while the available capacity was roughly 755,000 megawatts, resulting in a capacity margin of 14.6%.

- This decline in capacity margins; however, does not necessarily mean that the U.S. bulk power system is less reliable today than in the past. There are many reasons why lower capacity margins can result in the same level of reliability (e.g., power plants today are less likely to suffer from unexpected equipment failures).

SUMMER 2001

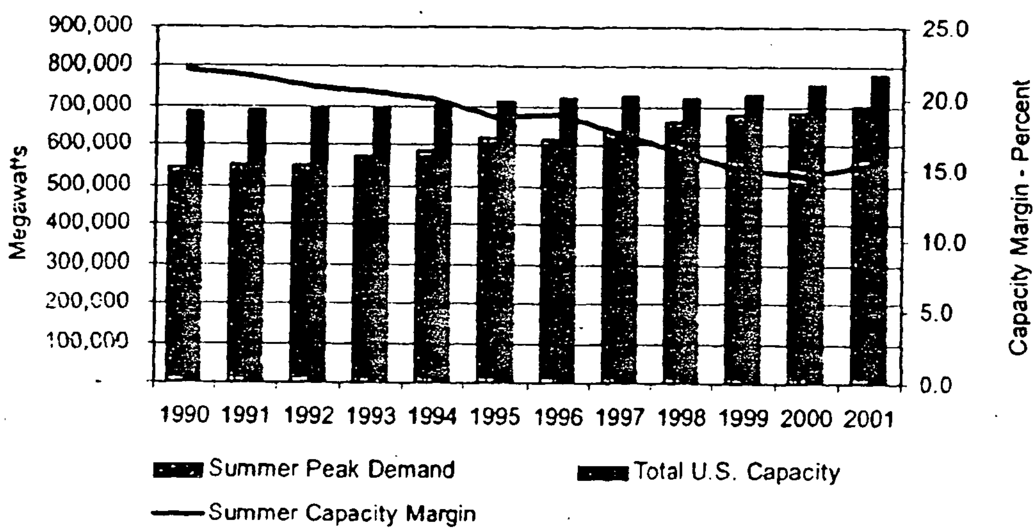
- NERC's most recent forecast for Summer, 2001, projects peak load will be 702,000 megawatts (assuming "normal" weather), while available capacity will be 782,000 megawatts, resulting in a small increase in this summer's national capacity margin compared to last summer.

- From January, 2000, through February, 2001, NERC seasonal assessments indicate that a net total of 26,500 megawatts of capacity will be added. This amounts to a 4% increase in capacity.

---

[1]Historical data (1990-1999) is from the North American Electric Reliability Council (NERC), *Electricity Supply & Demand 2000.* Note that final data for 2000 are not yet available. Data for 2000 and 2001 are projections from the NERC 2000 Ten-Year Reliability Assessment.

FIGURE 1: U.S. Capacity and Peak Demand: 1990-2001



REGIONAL OUTLOOK

While national estimates of peak demand and capacity can provide a starting point for a discussion of projected generation adequacy, these figures provide very little information regarding reliability because electricity markets and infrastructure have distinctive regional characteristics. Supply shortages in one region are often masked by surpluses in other regions when examining national data. Thus, region-by-region assessments are essential for identifying where generation capacity may be inadequate to meet peak demand.

Regional reliability assessments typically focus on the three major interconnections — the Eastern Interconnection, the Western Interconnection, and Texas (ERCOT). These three major interconnections are further broken down into ten NERC regional reliability councils (see Figure 2) NERC projections for peak demand and capacity in each NERC region for Summer 2001 are provided in Table 1. (As noted previously, these data are preliminary and subject to change as summer approaches and updated projections are received by NERC.)

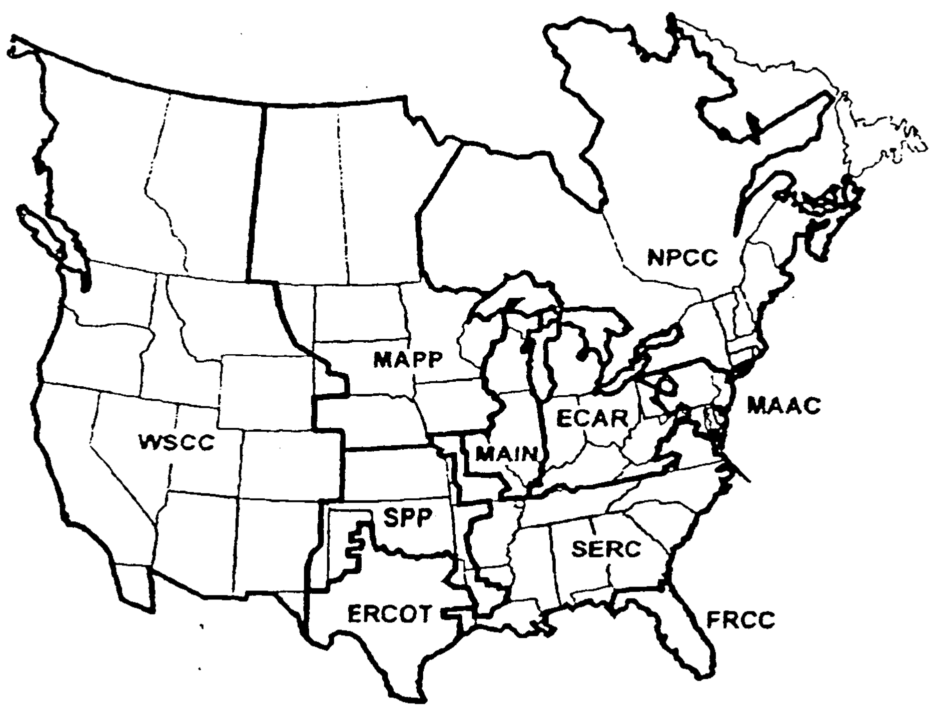


FIGURE 2: NERC Regional Map

858

DOE002-0868

TABLE 1: Regional Projections for Summer 2001

REGION	EXISTING CAPACITY As of Summer '99 (Megawatts)	CAPACITY ADDITIONS Jan 2000 through Feb 2001 (Megawatts)	PROJECTED CAPACITY FOR SUMMER 2001* (Megawatts)	PROJECTED PEAK DEMAND FOR SUMMER 2001 (Megawatts)
ECAR	105,980	3,717	108,426	99,562
ERCOT	59,504	6,594	69,839	56,501
FRCC	38,243	2,125	41,141	38,445
MAAC	57,703	1,215	59,802	51,762
MAIN	51,710	3,145	58,694	52,128
MAPP**	32,951	79	33,168	33,490
NPCC	58,621	2,127	64,443	54,170
SERC	150,254	4,810	161,155	156,533
SPP	42,643	651	44,071	40,127
WSCC	135,872	2,014	141,715	119,130
TOTAL	**733,481**	**26,485**	**782,454**	**701,848**

Source: NERC Electricity Supply & Demand 2000.

*Projections for Summer 2001 include additional capacity that might be added after February 2001 but before summer. Final data on capacity additions for 2000 is not yet available. Estimates of capacity additions through Feb 2001 (column 4) are based on ongoing NERC projections made throughout 2000. Some of these plants may not have in fact started operation in 2000.

**Data are for the U.S. only. Additional capacity in MAPP is located in Canada, giving the MAPP region an adequate overall capacity margin.

Table 2 provides new capacity data for each state.

Areas of Concern

CALIFORNIA

SUMMARY: California's electric power system, which has been experiencing unprecedented and increasingly frequent problems, is likely to experience even greater problems during the summer of 2001. The projected summer peak demand, which is a function of forecasted temperature and other parameters, is likely to be about 50% higher than current (winter) peak demands. Projected capacity shortfalls could exceed 4,000 MW (virtually every summer 2001 estimate for California projects electricity shortages, with some estimates as high as 12,000 MW), resulting in continued or even escalating energy emergencies. Under certain conditions, particularly situations involving multiple contingency events, such emergencies could lead to deep load shedding. In addition, because the Western power grid is so highly interconnected, problems in California could adversely affect the Pacific Northwest and other regions of the West. The entire Western grid will remain vulnerable to unexpected events of large magnitude (e.g., loss of key high-voltage transmission lines, loss of large generating units, disruptions in natural gas supplies, etc.). Such events could cause cascading problems that lead to widespread, uncontrolled blackouts throughout the West.

BACKGROUND: For the past six months, California's Independent System Operator (CA-ISO), the not-for-profit corporation chartered by the state to manage the flow of electricity along the long-distance, high-voltage power lines that make up about 75% of California's electricity grid, has struggled to meet daily electricity demands. The State experienced record curtailments and rolling blackouts affecting hundreds of thousands of customers in northern and central California in January, and Stage 3 emergency alerts, which are issued when operating reserves are forecasted to be less than one-and-a-half percent, have been a daily occurrence for a record 25 days

ASSESSMENT: The California Independent System Operator (CAL-ISO) indicated in November 2000 that 2001 Summer demands could exceed available resources at the time of peak by 253 MW (mild temps) to 4,152 MW (hot temps). These projections include imports of 4,500 MW from outside the ISO, 1,421 MW of new generation, continued operation of CAL-ISO's 44,050 MW of existing generation (except for any generator maintenance outages and deratings due to low water conditions at hydro facilities), and a provision for required operating reserves. (Interruptible demands have not be subtracted from the demand forecast, but that may be academic as all of the hours of interruption allowed under these contracts were used up during the month of January.)

In the northern part of the state, hydro-powered electric generators will be limited by low water levels, as will imports from the Pacific Northwest.

California has an internal transmission constraint that limits how much power can be moved from the southern to northern portions of the state (Path 15). Therefore, most of the reliability problems are expected to occur in northern California.

- Summer peak load estimates forecasted by the CA-ISO are in the 45,000 MW (mild summer temperatures) to 49,000 MW range (hot summer temperatures). The peak load for normal temperatures is estimated to be in the 47,000 MW range.

- Demand growth is estimated to be between 1.8 – 2.1%, although demand in some regions of the state is growing at nearly 15%.

- Summer peak demand includes electric motors driving compressors for air conditioners, which create more demanding inductive loads, rather than heating-based resistive loads, which are more easily managed. This characteristic creates system control problems that stress the grid. These problems are amplified during peak load conditions.

- In late January, PG&E had exhausted the entire 2001 annual allowance for the state's interruptible customer program. This program, which includes about 170 commercial and industrial customers, amount to about 400 MW.

Supply

- The installed capacity in California as of January 1, 2000, is about 52,700 MW. Although no major power plants have been built in California in the last 10 years, nine new generating plants are currently under construction in the state. The California Energy Commission estimates that 1,800 megawatts of new capacity will begin operation this summer.

- Estimates of the required imports to meet summer peak demands range from nearly 5,000 MW (mild summer temperatures) to over 8,500 MW. Expected import capacity is projected to be about 4,600 MW. Therefore, the demand for electricity during the summer 2001 could exceed supply by up to about 4,000 MW, depending on weather conditions, levels of conservation, the availability of electricity imports, the status of generating units, and other factors.

- There has been a severe lack of snow and rain in the Northwest, which depends on hydropower for about 75% of its electricity and has been a key source of emergency power for California in recent months. The Northwest River Forecast Center (Portland) estimates the January-July flow of water through the vast Columbia River basin at only 63% of normal. As a result, hydro reserves are low and as summer demands increase in the Pacific Northwest, hydro-based imports may not be readily available. This is likely to be a major constraint for the summer.

- Plant outages were higher in summer of 2000 than during summer of 1999. Unplanned outages were 3,391 MW in August, 2000, compared to 604 MW in August 1999. This is partly attributable to age of the generating units (82 percent of the fossil plants are over 30 years old, and 37 percent are over 40 years old), maintenance practices, and other factors. Since some plants were run beyond their normal maintenance intervals to meet winter demand, there may be an increase in forced outages over the summer months. An increase in unplanned outages could have a significant impact on available supply during peak times.

- California relies heavily on natural gas in meeting electric power requirements. Gas-fired generation accounted for 49% of power generated in the first nine months of last year. Only 16% of the natural gas consumed in California was produced in the state, leaving California highly dependent on natural gas imports into the state. California is serviced by four major pipelines. Transwestern Pipeline Co., a subsidiary of Enron Corp., operates a line from West Texas into Southern California; El Paso Corp's El Paso Natural Gas Co. runs another large pipeline largely parallel to Transwestern; PG&E Corp's PG&E Gas Transmission Co. brings gas down from Canada; and Williams Co.'s Kern River pipeline brings gas in from the Rocky Mountains.

- Working gas in storage in California is estimated to be more than 20% below the previous 5-year average. The estimated end-year level is the lowest on record. This situation has been exacerbated by the reluctance of the gas suppliers to provide additional inventory to the financially-strapped utilities. As a result, storage draw-down rates have increased even beyond the projections. If the Summer, 2001 gas demand is as strong as projected by EIA, then expectations are that the low end-winter storage levels will present a strong challenge to the North American gas supply system. Natural gas storage provides system flexibility, which is important in off-setting the load patterns of gas-fired generation. Natural gas prices in the West roughly tripled from January, 2000 to September, 2000.

Transmission

- The Pacific Northwest and California are electrically connected by two primary sets of transmission lines (AC and DC lines) that distribute the power generated by the federal dam system and other Northwest suppliers to California. Given the current state of the Western grid, any disruption of the AC transmission lines (a network of 500 kV transmission lines with over 4,800 MW of transfer capability) and/or the DC transmission line (a 1,000 kV line, with nearly 3,100 MW of transfer capability) could cause immediate large-scale blackouts throughout California. Such a massive perturbation to the grid would introduce instability problems that could threaten the entire Western region.

- A transmission bottleneck exists within central California on a group of high-voltage power lines (referred to as "Path 15") which often stalls the transfer of electricity from the south to the north. Congestion occurs when power demands exceed their transmission capacity of about 3,000 megawatts. Path 15 is critical because most of California's electricity reserves and large import capabilities from Arizona and Nevada (over 9,000 MW) are in the southern part of the state. Upgrades to Path 15 cannot be completed by the summer 2001.

- A number of transmission system upgrades near San Francisco and San Diego, including upgrades to transformers, are expected to be completed by the summer.

- The DC line has been the conduit through which southern California has been sending borrowed electricity back north to Oregon during off-peak hours (thus avoiding the Path 15 bottleneck). It has also been used in some instances to send power back to northern California (via Oregon and the AC transmission lines) to meet peak demands.

Interdependencies

- The loss of electric power can lead to significant problems in other infrastructures that depend on that power (e.g., natural gas, oil, telecommunications, water supply systems, transportation, banking and finance, and emergency services). It would also lead to significant business and economic, agricultural, health and safety, and national security impacts. Such "cascading" problems among the interdependent infrastructures have been seen in recent weeks in California as a result of curtailments and rolling blackouts.

PACIFIC NORTHWEST

SUMMARY: The Pacific Northwest is heavily dependent on hydro-powered electric generation. Stream flows and reservoir levels are at critically low levels. The key hydro indicator in the Northwest is runoff at the Dalles Dam on the Columbia Reiver. Current flow is about 65% of normal, and this will be the 4th worst year on record unless they get heavy spring rains. The Pacific Northwest should be able to meet its own customer demand unless weather is extremely hot, but will likely not be able to supply California with energy as they typically do in the summer.

BACKGROUND: The information for this section is provided primarily by the Bonneville Power Administration and focuses mainly on the Federal Columbia River Power System. The Northwest Power Pool (NWPP), which includes seven states and two Canadian provinces, provided some input. Overall, NWPP expects the Northwest region to just meet its forecasted firm load.

Power planning is done on the basis of serving regional firm load for critical water year planning assumptions (1936-1937) which equates to approximately 11,000 average megawatts of firm energy load carrying capability. Under average water year conditions, the additional non-firm energy available is approximately 3000 average megawatts. However, in view of present overall West Coast conditions, including the extreme water condition, the Northwest region is estimating that it will be able to just meet firm loads and required forced outage reserves with no additional margin. Should any resources be lost to the region beyond the required forced outage reserves and or load be higher than normal the Northwest region will have to look to alternatives which may include initiating emergency measures to carry operation through a period of time.

ASSESSMENT:

Water Situation (see figures 1 and 2)

- Current below average streamflows coupled with an assumption of average conditions for the remainder of the water year result in a well below normal volume forecast for the January through July period.
- The current January-July volume forecast is 67 million acre feet (MAF) or 63 percent of normal.
- If the dry conditions continue, this would be among the five lowest water years the Northwest has experienced since record keeping began.

Hydro Generation (see figure 3)

- Below average streamflow conditions have resulted in reduced Federal hydropower generation relative to recent years that experienced average and above average streamflows.

- The projected 4,000-megawatt average reduction in Federal generation compared to generation in 1995 through 1999 is roughly equal to 4 times the amount of energy consumed by the city of Seattle.

Thermal Generation

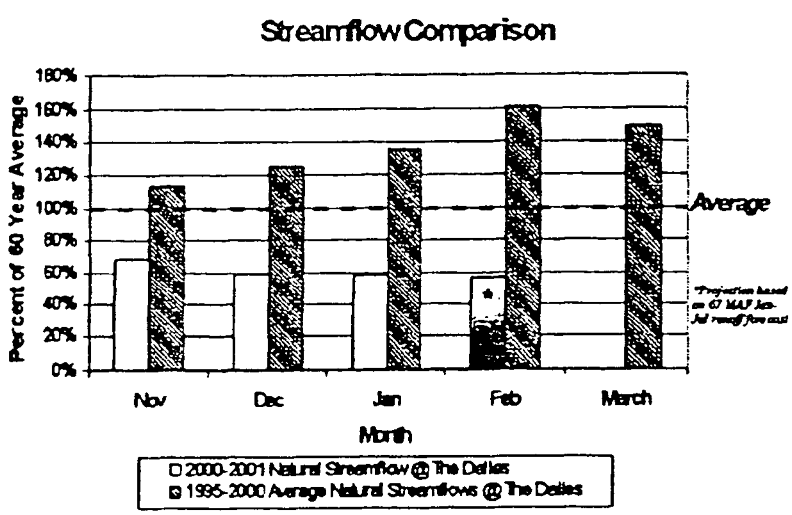
- Thermal generating resources in the region are expected to be normal for the summer period with no problem areas indicated in this area.

Transmission

- Operational transfer capabilities for moving power to and from the Northwest are based on regular seasonal studies by the Western System Coordinating Council and its members. Studies for the summer period are scheduled to be completed during the spring period.

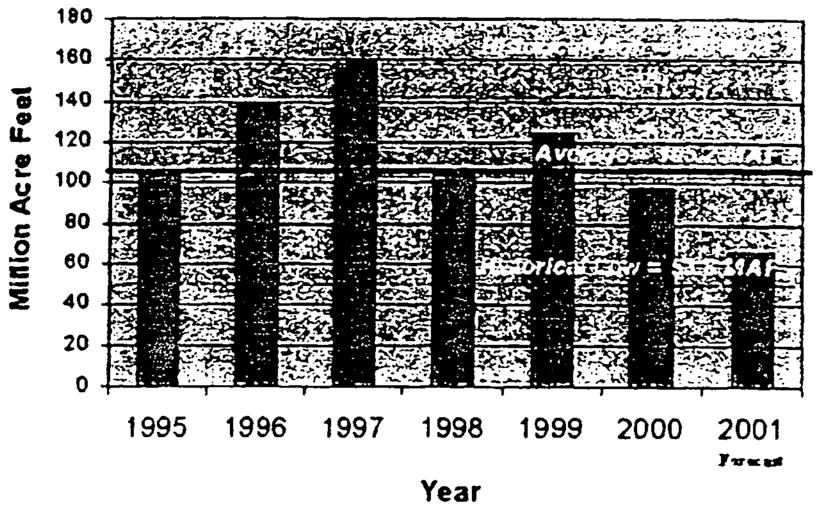
- It is not anticipated that transmission will be a limiting factor for serving Northwest load.

The Water Situation



The Water Situation

January-July Runoff Above The Dalles



NEW YORK CITY

SUMMARY: Electricity supplies will be tight this summer in NYC but supplies should be adequate to serve peak summer loads. The likelihood of shedding firm load due to supply inadequacy is small. The likelihood of widespread distribution system failures similar to those that occurred in 1999 is also small.

BACKGROUND: NYC is a "load island" meaning its peak electric demand exceeds its generation resources and it has to rely on electricity imports via the transmission system. Consolidated Edison (ConEd) estimates the NYC peak load and resources for this summer are:

In-City Generation:	8, 480 MW
Transmission Imports:	5,000 MW
Total Resource:	13, 480 MW
Peak Load:	10,600 MW

- Historical summer generator availability is approximately 90 percent.

- During the summer of 1999, New York City experienced electric power outages due to stress on its distribution system during extremely hot weather and heavy load conditions. Since that time, Consolidated Edison has improved maintenance practices and inspection schedules.

- The 2000 summer peak load was 11,825 MW and the all-time summer peak was 11,850 MW in 1999.

- The in-city generation includes approximately 400 MW of new gas-fired, combustion turbines that will be installed by June 1 by the New York Power Authority to improve electric reliability over the summer. These 40-MW generator units are being installed in sets of two and are rated at 79 MW to avoid siting requirements for generation of 80 MW and greater. Currently, the largest generator in NYC is 950 MW.

- NYC has a unique summer reliability requirement when thunderstorms approach from the West and increase the risk of losing a transmission line. During "thunderstorm alerts" the system must operate based upon the contingency of losing three 345- KV transmission lines. Normally the contingency is two 345-KV lines.

ASSESSMENT: With a state-wide 18 percent capacity reserve requirement, NYC must have 12,508 MW to serve its 10,600 MW peak load. Assuming all transmission import capability is available (5,000 MW) and a 90 percent generator availability rating (90% x 8450 MW), leaves

12,632 MW to meet the peak load requirement. The 124-MW buffer (12,632 MW - 12,508 MW) is very slim. If transmission lines go out of service or an unusually high generator outage rate occurs, ConEd would be forced to implement load reduction measures, which include heightened levels of conservation, curtailment of interruptible loads, voltage reductions and, in extreme cases, shedding firm loads. The likelihood of shedding firm load in New York City due to inadequacy of supply is small. While distribution system outages are always a possibility when equipment fails, we do not anticipate significant distribution outages (similar to those of 1999) this summer in NYC.

LONG ISLAND

SUMMARY: Electricity supplies will be tight this summer on Long Island but supplies should be adequate to serve peak summer loads. The likelihood of shedding firm load due to supply inadequacy is small. The voltage instability problem that occurred in 1999 has been corrected.

BACKGROUND: Long Island is a "load island" meaning its peak electric demand exceeds its generation resources and it has to rely on electricity imports via the transmission system. KetSpan Corporation serves most of the load on Long Island. Several municipal utilities with a total of about 140 MW of generation capacity also operate on Long Island. This discussion focuses on KeySpan's system. KeySpan estimates its peak load and resources for this summer are:

Generation Available:	4,386 MW
Transmission Imports:	1,200 MW
Total Resource:	5,586 MW
Peak Load:	4,468 MW

- Historical summer generator availability is approximately 90 percent.

- During the summer of 1999, Long Island experienced electric power outages due to stress on its distribution system during extremely hot weather and heavy load conditions. They also experienced widespread voltage drops and near voltage collapse in the South Fork area on the eastern end of the island. The low voltage conditions resulted from the inability of KeySpan to supply sufficient generation to serve heavy loads. Contributing to the electricity supply problem was the loss of significant transmission import capability due to a large transformer failure. Since that time, KeySpan has upgraded their transmission system including the addition of a 138-KV transmission line to the South Fork area and replacement of the damaged transformer.

- The all-time summer peak load was 4,590 MW during the summer of 1999.

- The Island's generation includes a new 40-MW gas-fired, combustion turbines that will be installed by June 1 by the New York Power Authority to improve electric reliability over the summer.

ASSESSMENT: There is a state-wide 18 percent capacity reserve requirement; however KeySpan reports that it has a somewhat less operating reserve margin of approximately 500 MW. Thus, KeySpan must have 4,968 MW to serve its estimated 4,486-MW peak load. Assuming all transmission import capability is available (1,200 MW) and a 90 percent generator availability rating (90% x 4,386 MW), leaves 5,147 MW to meet the peak load requirement. The 179-MW buffer (5,147 MW - 4,968 MW) is very slim. If transmission lines go out of service, as happened in 1999, or an unusually high generator outage rate occurs, KeySpan would be forced to implement load reduction measures, which include heightened levels of conservation, curtailment of interruptible loads, voltage reductions and, in extreme cases, shedding firm loads. The likelihood of shedding firm load on Long Island due to inadequacy of supply is small. While distribution system outages are always a possibility when equipment fails, we do not anticipate significant distribution outages (similar to those of 1999) this summer on Long Island.

MIDWEST

SUMMARY: For the summer of 2001, generation resources in the Midwest are generally adequate, but there are some areas that may experience tight generation supplies, which will result in capacity reserve margins falling below recommended minimums. Recent transmission facility expansions are expected to keep transmission reliability parameters for much of the region within acceptable limits. There are, however, a few areas where transmission congestion may be experienced.

BACKGROUND: The northern Midwest, particularly the area around the Chicago metropolitan area, experienced numerous electric power reliability problems in the summer of 1999. These were primarily related to problems with the distribution system and were not the result of supply shortages in generation or constraints in transmission system capability. The summer of 2000 had cool temperatures, which reduced demand below expected levels. As a result, power was available for sales to other areas for most of the summer.

ASSESSMENT:

Demand

- Summer peak demands are projected to increase at between 1.5-2.0% in the region. Peak loads are projected to be 52,000 MW in MAIN, 31,200 MW in MAPP-US, and 99,600 MW in ECAR.

- The slowing of the economy has resulted in somewhat lower than expected sales of electricity in the first month of 2001. Whether this trend continues into the summer is uncertain at this time.

- Summer peak demand is driven by loads from air conditioner motors, whose performance characteristics create system control problems. These problems are amplified during peak load conditions.

Supply

- In the MAIN region of the Midwest (including Illinois, and parts of Wisconsin and Missouri) more than 3,000 MW of new capacity was added in 2,000. An additional 2,000-4,000 MW is projected to be on line before summer. The majority of the additions are in the form of peaker plants. With these additions, reserve margins expected to be within the NERC-recommended levels of 17-20%.

- In the U.S. portion of the MAPP region of the Midwest (including Minnesota, Iowa, North and South Dakota, Nebraska, and portions of Wisconsin and Idaho) generating capacity has been judged by NERC to be inadequate. Summer reserve margins are projected to decline to 14%, which is below the recommended level.

- In the ECAR region (including Indiana, Ohio, Michigan, Kentucky, and West Virginia) capacity margins are expected to be in the 9-11% range. There is a need for substantial new generation capacity and/or import capability to meet demand. Indiana is planning on 925 MW of new merchant plant capacity to be on-line by summer. Ohio is planning for 1,330 MW of new capacity. Aging plants and environmental restrictions on coal use, which is the predominant fuel in the region, present reliability challenges.

- Nuclear units in the region are expected to be at full capacity during the summer peak period.

- The impact of merchant generation has become a concern. Uncertainties regarding size, location, and in-service dates of the new plants has become challenging for the planning process.

- In the absence of a formal independent system operator or regional transmission organization for the Midwest and with traditional utilities no longer owning many of the power plants serving the area, there is concern over how the operation of these plants is being monitored from a system reliability perspective.

Transmission

- In the MAIN region, transmission capacity is generally adequate. Early completion of Commonwealth Edison's Lockport-Lombard 345 kV line has relieved some of the congestion that had been experienced in this corridor in the past. The Wisconsin Upper Michigan Interconnected System import capability is, however, inadequate. The western Eau Claire-Arpin 345 kV interface within this system constrains electricity imports from the west.

- In the U.S. portion of the MAPP region, the transmission system is judged to be adequate to meet firm obligations. There may, however, be potential restrictions if outages on certain lines, particularly near Minneapolis-St. Paul, limit energy transfers from the Twin Cities to Iowa and Wisconsin.

- The transmission networks in ECAR are expected to meet adequacy and security criteria over a wide range of anticipated system conditions as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service as planned.

- Several utilities in the northern Midwest region have already acquired firm transmission rights with the intention of utilizing those rights to acquire available power from other utilities in the region. This will assist in meeting demand during periods of normal and locally high demand. However, this leaves many of these utilities susceptible to price spikes and/or a lack of availability of generation in cases of concurrent peak demand among the region's utilities.

SOUTHEASTERN UNITED STATES

SUMMARY: Conditions in the Southeast are expected to be much the same as the last two summers - extremely tight. A number of new generators are planned to be added by the summer. However, there may be problems delivering the energy from some of these generators to the demand centers because the transmission system additions needed to connect these generators into the transmission system are lagging the construction of generators. Some existing generators are scheduled to be out of service this spring for maintenance to add emissions related equipment. This has the potential to reduce available resources at a critical time of the year.

TEXAS

SUMMARY: Texas projects adequate capacity margins, but there are still some causes for concern in the state. Texas forecasts about 8,000 MW of new generation being added for the summer, but about 2,500 MW of this new generation is in an area of West Texas that prevents it from being delivered widely throughout Texas due to limitations in the transmission system. Some of the new generation is on the border between Texas and the southeastern United States and may not be used to serve the customers of Texas.

Texas experienced prolonged, extreme temperatures last summer, which required some generators to run many more hours than normal. This could lead to increased generator breakdowns this summer (like California experienced this winter).

A retail access pilot program is scheduled to commence on June 1, 2001 in Texas, and the ten power system operating centers (Control Areas) will be consolidated into a single center. Because June is a time of heavy electrical demand in Texas, this situation bears careful watching.

THE NORTHEAST

SUMMARY: The northeastern United States experienced a very cool summer last year. If temperatures had been normal, it is very likely that New York and New England would have experienced serious electricity supply problems. While conditions have improved in this region since last summer, it is still susceptible to shortages if customer demand exceeds expectations due to abnormally hot weather, or if a significant number of generators are unexpectedly out of service.

Last summer, New York City experienced some minor supply shortages due to a lack of sufficient transmission into the city. About 440 MW of new generation will be added in distributed locations around New York City by Summer 2001, which should help alleviate this condition and contribute resources to serving total demand in the state.

BAKER BOTTS LLP

February 5, 2001

Summary and Excerpts

Federal Energy Regulatory Commission
Report on Plant Outages in the State of California

Prepared by: Office of the General Counsel,
Market Oversight & Enforcement;
Office of Markets, Tariffs and Rates
Division of Energy Markets

February 1, 2001

The Report summarizes an audit of generating plant outages in California, conducted by FERC Staff, with the objective of determining whether unplanned maintenance or outages occurred to raise electricity prices in California. The Report focuses specifically on plant outages, electricity shortage and high prices in California in December 2000.

The information contained in the Report was collected through telephone interviews, site visits to plants in California, and visits to company headquarters. Reliant information was obtained from site visits to plants in Daggett and Oxnard, California and through interviews at the corporate headquarters in Houston, Texas. The Report contains detailed data on four of Reliant's five plants located in California and over ninety percent of Reliant's generation that serves the California market. Approximately half of the published Report deals directly with Reliant's continued efforts to maintain its generating units and serve the California market. The Report also has slightly less detail on some generating units owned by West Coast (Dynegy) and some information on plants owned by Southern Energy California.

As an introductory conclusion, the Report states the following: "Staff did not discover any evidence suggesting that the audited companies were scheduling maintenance or incurring outages in an effort to influence prices. Rather, *the companies appeared to have taken whatever steps were necessary to bring the generating facilities back on-line as soon as possible by accelerating maintenance and incurring additional expenses*. Also, the outages did not necessarily correlate to the movement of prices on a given day." (p. 1, emphasis added)

As a final conclusion, the Report states the following: "After reviewing the detailed materials provided by West Coast (Dynegy/NRG) and Reliant, it appears the older units owned by these companies have all experienced similar problems based on increased demand and the age of the units. . . . *Staff did not discover any evidence suggesting that the companies reviewed in detail here, West Coast (Dynegy/NRG) and Reliant, were scheduling maintenance or incurring outages in an effort to influence prices or to obtain leverage in negotiations with the ISO.* Rather, it appears that these companies accelerated maintenance and incurred additional expense to accommodate the ISO's operating needs. They also reduced outages and deferred maintenance in December [2000] and preserved revenue opportunities by doing so. The detailed site reviews are therefore consistent with the results displayed by the aggregated time series data discussed in the introduction of this report, that prices and maintenance have generally moved in an inverted pattern and *the prices are driven by demand, not the companies' maintenance practices*." (p. 52, emphasis added)

The text of the Report lends support to the conclusion that high prices were the result of normal market forces, particularly scarcity and over-use of resources. In analyzing basic market trends, the Report states the following: ". . . while prices moved sharply higher between the 9th and the 13th [of December 2000], outages moved generally downward in the same period, including forced outages. . . . [T]he decline in all outages as prices increased in consistent with an expectation that periods of constrained demand and higher prices would encourage additional load to come forward, both because of a response to the ISO requirements and an opportunity to earn revenues that exceed the marginal cost of operating units that may have higher operating expenses or a greater risk of system failure. Thus, to the extent that maintenance of any type could be deferred, or more tightly controlled, to meet demand and increase revenues, this appears to have been what happened during December." (p. 6)

The Report shows that Reliant expended major amounts of money in 2000 maintaining and improving its plants. For example, for its Coolwater plant in Daggett, California, Reliant spent $23.1 million on major maintenance to keep the units running in 2000, compared to $ 1.0 million in 1998 and $1.2 million in 1999. (p. 15) Reliant also spent $11 million in 2000 for maintenance on its plant in Oxnard, California, compared to $ 5.9 million expended in 1999 for the same plant. (p. 23)

The Report details maintenance needs addressed by Reliant in 2000, and also explains other limits on Reliant's operation, such as environmental requirements that limit the number of hours a plant is permitted to operate in a year. (*e.g.*, pp. 19, 32) The Report also explains steps Reliant took, including investment in programs to develop alternative pollution control technologies, to obtain permission to operate additional hours, after one of its plants reached its environmental limit in July 2000. These steps enabled Reliant to supply an additional 27,000 MWh of electricity to the California market in 2000. (p. 32)

The Report details instances when Reliant has been willing to defer maintenance plans because conditions indicated increased need for electricity in California, or because the California ISO requested that Reliant do so. (*e.g*,. pp. 33, 34) Sometimes these plants were brought into service or kept in service despite the need for repairs or despite previous decisions by Reliant that they the plants would not run for economic reasons or for maintenance reasons. (*e.g*,. pp. 26, 33, 34, 36)

As noted in the Report, when the ISO has called and requested that a plant run, Reliant has honored that request. (p. 36)

229

EDISON ELECTRIC INSTITUTE

Rankings of Investor-Owned Electric Utilities

2000 EDITION

877

DOE002-0887

TABLE OF CONTENTS

Foreword iii
Selected Statistics of the Total United States Investor-Owned Electric Utility Industry iv

Section I - Selected Rankings of Consolidated Financial Data
Top 5, by Assets, Electric Operating Revenues, and Total Electric Operating Revenues (chart) 1
Top 50, by Total Assets 2
Top 50, by Total Operating Revenues 3
Top 50, by Market Capitalization 4
Top 50, by Total Company Employees 4
Top 50, by Total Electric Operating Revenues 5

Section II - Rankings of Operating Companies by Ultimate Customers
Top 5, by Residential, Commercial, and Industrial Customers (chart) 7
Top 50, by Total Ultimate Customers 8
Top 50, by Residential Customers 8
Top 50, by Commercial Customers 9
Top 50, by Industrial Customers 9

Section III - Rankings of Operating Companies by Sales to Ultimate Customers
Top 5, by Residential, Commercial, and Industrial Sales (chart) 11
Top 50, by Total Sales to Ultimate Customers 12
Top 50, by Sales to Residential Customers 12
Top 50, by Sales to Commercial Customers 13
Top 50, by Sales to Industrial Customers 13

Section IV - Rankings of Operating Companies by Revenues from Sales to Ultimate Customers
Top 5, by Residential, Commercial, and Industrial Revenues (chart) 15
Top 50, by Total Revenues from Sales to Ultimate Customers 16
Top 50, by Revenues from Sales to Residential Customers 16
Top 50, by Revenues from Sales to Commercial Customers 17
Top 50, by Revenues from Sales to Industrial Customers 17
Comparative Ranking of Revenues, Sales, and Ultimate Customers 18

Section V - Additional Rankings of Operating Companies
Top 5, by Net Generation, Sales for Resale, and Electric Department Employees (chart) 19
Top 50, by Net Generation 20
Top 50, by Sales for Resale 20
Top 50, by Electric Department Employees 21
Top 10, by Fossil Fuel Receipts 22

Section VI - Miscellaneous
Investor-Owned Electric Utility Holding Companies and Systems 24
Investor-Owned Electric Utility Mergers and Company Name Changes 29
Glossary of Terms 30
Publications Prepared by the Statistics Department

FOREWORD

This publication contains rankings of investor-owned electric utility companies by a number of data items that are frequently used to evaluate the comparative size and scope of industry participants. The EEI Statistics Department receives a number of requests for this type of information, therefore, we have compiled the most frequently requested rankings for inclusion in this publication. The following sources were used to compile the data: Securities and Exchange Commission (SEC) 10-K reports), Company Annual Report to Stockholders, Federal Energy Regulatory Commission (FERC) Form No. 1, and the Department of Energy, Energy Information Administration (DOE/EIA) Forms 759 and 861.

All of the rankings are based on data for the reporting year 1999. Company names included in this document are those that were in effect as of December 31, 1999. Since this time however, several companies have been affected by mergers and name changes. Please refer to page 29 for a list of companies that have merged or changed names since August 1, 1999. See page 24 for a listing of holding companies and subsidiaries, updated through October, 2000.

Most rankings include the top 50 investor-owned electric utility companies. Operating data have been arrayed by operating company*, while the financial data are presented on a consolidated basis. In response to the increasing number of requests for rankings of consolidated or holding companies, we have included the following rankings on a consolidated company basis: Top 50 Electric Utilities and Holding Companies by Total Operating Revenues; Top 50 Electric Utilities and Holding Companies by Market Capitalization; and Top 50 Electric Utilities and Holding Companies by Total Number of Employees.

*Operating data shown for Duke Power Co. in Sections I - V of this publication include operating data for Nantahala Power & Light Co.

SELECTED 1999 STATISTICS OF THE INVESTOR-OWNED ELECTRIC UTILITY INDUSTRY

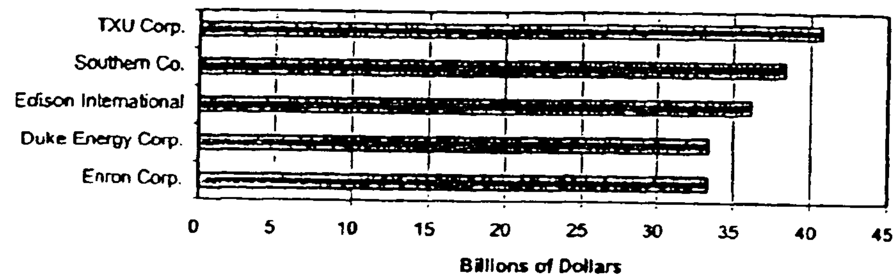
Installed Generating Capacity (p)	483,746 MW
Generation	2,297,834 GWh
Ultimate Customers	
Total	92,408,587
Residential	81,115,934
Commercial	10,433,991
Industrial	389,204
Sales to Ultimate Customers (GWh)	
Total	2,397,707
Residential	802,834
Commercial	763,913
Industrial	766,789
Revenues from Sales to Ultimate Customers	
($000's)	$163,664,990
Total	68,275,866
Residential	56,287,443
Commercial	34,747,270
Industrial	
Assets (in Millions) (p)	$775,437
Total Operating Revenues (in Millions) (p)	$365,703

p Preliminary. MW = megawatt = one thousand kilowatts. GWh = gigawatthour = one million kilowatthours.

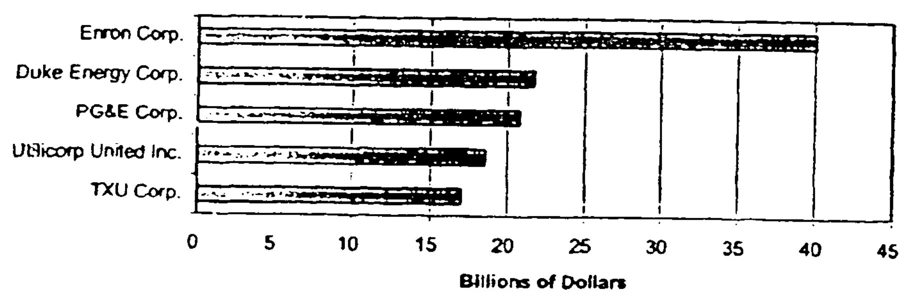
SECTION I
Selected Rankings of Consolidated Financial Data

TOP 5 COMPANIES BY

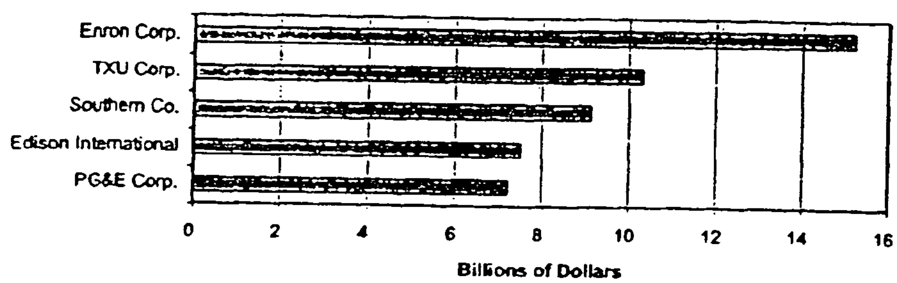
1999 Assets



1999 Total Operating Revenues



1999 Total Electric Operating Revenues



TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES AND HOLDING COMPANIES WITH REGULATED UTILITY OPERATIONS

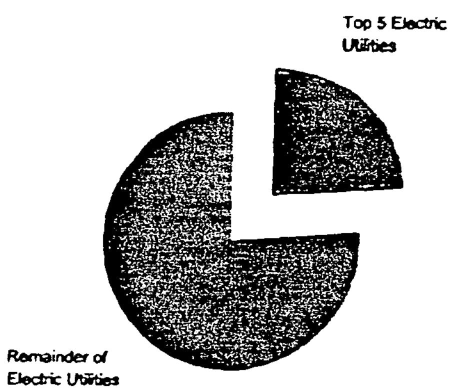
TOTAL ASSETS - 12/31/99
Millions of Dollars

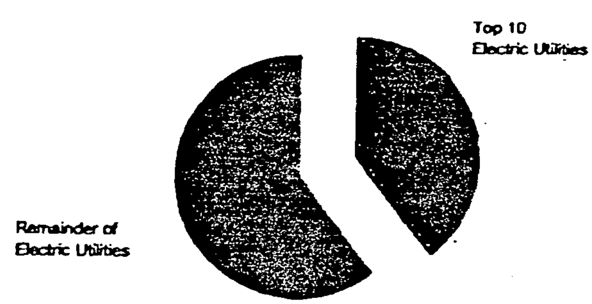
Rank	Company Name	Assets	Rank	Company Name	Assets
1	TXU Corp.	$40,741	26	Northern States Power Company - MN	9,768
2	Southern Co.	38,396	27	Northeast Utilities	9,688
3	Edison International	36,229	28	Constellation Energy Group	9,684
4	Duke Energy Corp.	33,409	29	Cinergy Corp.	9,617
5	Enron Corp.	33,381	30	Carolina Power & Light Co.	9,494
6	PG&E Corp.	29,715	31	Ameren Corp.	9,178
7	Reliant Energy	26,221	32	New Century Energies	8,322
8	Unicom Inc.	23,406	33	Hawaiian Electric Industries Inc.	8,291
9	Entergy Corp	22,985	34	Western Resources, Inc.	8,008
10	GPU Inc.	21,718	35	Utilicorp United Inc.	7,539
11	American Electric Power Inc.	21,488	36	Potomac Electric Power Co.	6,911
12	Public Service Enterprise Group, Inc	19,015	37	Allegheny Energy, Inc.	6,852
13	FirstEnergy Inc.	18,224	38	NiSource Inc.	6,835
14	Dominion Resources Inc.	17,747	39	KeySpan Energy Corp.	6,731
15	Consolidated Edison Inc.	15,531	40	Pinnacle West Capital Corp.	6,609
16	CMS Energy Corp.	15,462	41	Florida Progress Corp.	6,528
17	Central & South West Corp.	14,162	42	Wisconsin Energy Corp.	6,233
18	FPL Group Inc.	13,441	43	Conectiv	6,138
19	PECO Energy Inc.	13,120	44	Alliant Energy Corp.	6,076
20	Niagara Mohawk Power Corp.	12,670	45	SCANA Corp.	6,011
21	DTE Energy Inc.	12,316	46	DQE	5,609
22	Pacificorp *	12,194	47	NSTAR	5,483
23	Sempra Energy	11,270	48	Illinois Power Company	5,298
24	PP&L Resources, Inc.	11,174	49	Sierra Pacific Resources	5,248
25	MidAmerican Energy Holdings Co.	10,766	50	Puget Sound Energy, Inc.	5,146

* As of March 31, 2000

Data were compiled from Consolidated assets as reported on Balance Sheets prepared for company annual reports and SEC 10-K form.

Total Assets





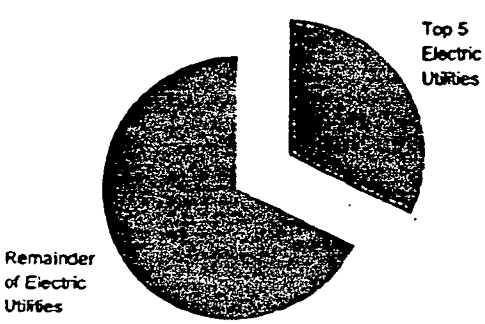
TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES AND HOLDING COMPANIES WITH REGULATED UTILITY OPERATIONS

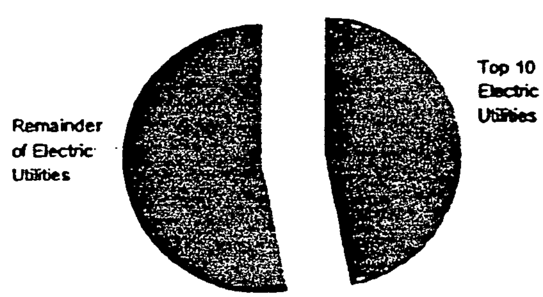
TOTAL OPERATING REVENUES - 12/31/99
Millions of Dollars

Rank	Company Name	Total Operating Revenues	Rank	Company Name	Total Operating Revenues
1	Enron Corp.	$40,112	26	Northeast Utilities	4,471
2	Duke Energy Corp.	21,742	27	MidAmerican Energy Holdings Co.	4,399
3	PG&E Corp.	20,820	28	Niagara Mohawk Holdings Inc.	4,084
4	Utilicorp United Inc.	18,622	29	Pacficorp *	3,987
5	TXU Corp.	17,118	30	Florida Progress Corp.	3,845
6	Reliant Energy	15,303	31	Constellation Energy Group, Inc.	3,786
7	Southern Co.	11,585	32	Conectiv	3,745
8	Edison International	9,670	33	Ameren Corp.	3,524
9	Entergy Corp.	8,773	34	New Century Energies	3,375
10	Avista Corp.	7,905	35	Carolina Power & Light Co.	3,358
11	Consolidated Edison, Inc.	7,491	36	NiSource Inc.	3,145
12	American Electric Power Company, Inc.	6,916	37	Northwestern Corp.	3,004
13	Unicom Corp.	6,848	38	KeySpan Energy Corp.	2,955
14	Public Service Enterprise Group, Inc.	6,497	39	Northern States Power Co.	2,869
15	FPL Group, Inc.	6,438	40	Allegheny Energy, Inc.	2,808
16	FirstEnergy Corp.	6,320	41	LG&E Energy Corp.	2,707
17	CMS Energy Corp.	6,103	42	Potomac Electric Power Co.	2,476
18	Cinergy Corp.	5,938	43	Pinnace West Capital Corp.	2,423
19	Central & South West Corp.	5,537	44	Energy East Corp.	2,279
20	Dominion Resources, Inc.	5,520	45	Wisconsin Energy Corp.	2,273
21	PECO Energy Co.	5,437	46	Alliant Energy Corp.	2,198
22	Sempra Energy	5,435	47	OGE Energy Corp.	2,172
23	GPU Inc.	4,757	48	Puget Sound Energy	2,067
24	DTE Energy Co.	4,728	49	Western Resources, Inc.	2,036
25	PP&L Resources, Inc.	4,590	50	TECO Energy, Inc.	1,983

* As of March 31, 2000
Data compiled from Income Statements as reported on company annual reports and SEC 10-K form.

Total Operating Revenues





883

DOE002-0893

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES AND HOLDING COMPANIES WITH REGULATED UTILITY OPERATIONS

MARKET CAPITALIZATION - 12/31/99

Millions of Dollars

Rank	Company Name	Market Capitalization	Rank	Company Name	Market Capitalization
1	Duke Energy	$18,296	26	PP&L Resources, Inc.	3,607
2	Southern Co.	15,933	27	New Century Energies	3,502
3	TXU Corp.	9,815	28	CMS Energy Corp.	3,399
4	Edison International	9,092	29	KeySpan Energy Corp.	3,165
5	Public Service Enterprise Group, Inc.	7,632	30	Allegheny Energy, Inc.	3,074
6	Consolidated Edison of NY, Inc.	7,625	31	New England Electric System	3,072
7	PG&E Corp.	7,524	32	Northern States Power Co.	2,996
8	Dominion Resources Inc.	7,512	33	SCANA Corp.	2,784
9	FPL Group Inc.	7,321	34	Potomac Electric Power Co.	2,719
10	Unicom	7,303	35	Northeast Utilities Inc.	2,702
11	Reliant Energy	6,526	36	Energy East Corp.	2,685
12	PECO Energy	6,484	37	DPL	2,616
13	Entergy Corp.	6,341	38	Niagara Mohawk Holdings Inc.	2,611
14	American Electric Power, Inc.	6,232	39	DQE Inc.	2,609
15	FirstEnergy	5,137	40	Pinnacle West Capital Corp.	2,590
16	Carolina Power & Light Co.	4,858	41	TECO Energy, Inc.	2,448
17	DTE Energy	4,549	42	ILLINOVA Corp.	2,429
18	Ameren	4,494	43	LG&E Energy Corp.	2,262
19	Constellation Energy	4,338	44	Wisconsin Energy Corp.	2,258
20	Central & SouthWest Corp.	4,252	45	NISource, Inc.	2,234
21	Florida Progress Corp.	4,159	46	Alliant Energy	2,161
22	Sempra Energy	4,124	47	NSTAR	1,930
23	Montana Power Co.	3,973	48	UtiliCorp United, Inc.	1,798
24	Cinergy Inc.	3,804	49	Puget Sound Energy	1,639
25	GPU Inc.	3,720	50	Conectiv	1,571

TOTAL EMPLOYEES

(Company Consolidated)

Year -1999

Rank	Company Name	Employees	Rank	Company Name	Employees
1	Southern Co.	32,949	26	Constellation Energy Group, Inc.	9,000
2	PG&E Corp.	22,433	27	Cinergy Corp.	8,950
3	TXU Corp.	21,984	28	DTE Energy Co.	8,886
4	Duke Energy Corp.	21,000	29	Pacificorp *	8,832
5	Edison International	19,570	30	Minnesota Power	8,000
6	Enron Corp.	17,900	31	Carolina Power & Light Co.	7,752
7	American Electric Power Go., Inc.	17,306	32	KeySpan Energy Corp.	7,723
8	Unicom Corp.	14,435	33	Pinnacle West Capital Corp.	7,534
9	Consolidated Edison, Inc.	14,269	34	Niagara Mohawk Holdings Inc.	7,400
10	Reliant Energy	14,256	35	NiSource Inc.	7,399
11	FirstEnergy Corp.	13,461	36	Ameren Corp.	7,347
12	Entergy Corp.	12,375	37	Western Resources, Inc.	7,049
13	Public Service Enterprise Group, Inc	11,891	38	Alliant Energy Corp.	6,217
14	PECO Energy Co.	11,737	39	New Century Energies	6,191
15	CMS Energy Corp.	11,462	40	LG&E Energy Corp.	5,836
16	Sempra Energy	11,248	41	Wisconsin Energy Corp.	5,706
17	Dominion Resources, Inc.	11,035	42	SCANA Corp.	5,488
18	Central & South West Corp.	10,928	43	TECO Energy, Inc.	5,487
19	GPU Inc.	10,800	44	Allegheny Energy, Inc.	4,923
20	FPL Group, Inc.	9,783	45	Conectiv	4,847
21	MidAmerican Energy Holdings Co.	9,700	46	Energy East Corp.	3,838
22	Florida Progress Corp.	9,329	47	MDU Resources Group, Inc.	3,791
23	PP&L Resources, Inc.	9,166	48	Potomac Electric Power Co.	3,603
24	Northeast Utilities	9,099	49	DQE	3,578
25	Northern States Power Co.	9,098	50	NSTAR	3,400

* As of March 31, 2000

884

DOE002-0894

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES AND HOLDING COMPANIES WITH REGULATED UTILITY OPERATIONS

TOTAL ELECTRIC OPERATING REVENUES - 12/31/99

Millions of Dollars

Rank	Company Name	Electric Operating Revenues	Rank	Company Name	Electric Operating Revenues
1	Enron Corp.	$15,238	26	PP&L Resources, Inc.	2,758
2	TXU Corp.	10,318	27	CMS Energy Corp.	2,667
3	Southern Co.	9,125	28	Florida Progress Corp.	2,633
4	Edison International	7,522	29	New Century Energies	2,527
5	PG&E Corp.	7,232	30	Conectiv	2,460
6	Unicom Corp.	6,848	31	Northern States Power Co.	2,397
7	American Electric Power Company, Inc.	6,315	32	Pinnacle West Capital Corp.	2,293
8	Entergy Corp.	6,271	33	Allegheny Energy, Inc.	2,274
9	FPL Group, Inc.	6,057	34	Constellation Energy Group, Inc.	2,258
10	Consolidated Edison, Inc.	5,793	35	Potomac Electric Power Co.	2,219
11	FirstEnergy Corp.	5,453	36	Wisconsin Energy Corp.	2,050
12	Duke Energy Corp.	4,934	37	MidAmerican Energy Holdings Co.	1,918
13	PECO Energy Co.	4,847	38	Energy East Corp.	1,889
14	DTE Energy Co.	4,728	39	Sempra Energy	1,818
15	Reliant Energy	4,483	40	NSTAR	1,711
16	Northeast Utilities	4,400	41	Illinois Power Company	1,599
17	Cinergy Corp.	4,313	42	Puget Sound Energy	1,558
18	Dominion Resources, Inc.	4,274	43	Alliant Energy Corp.	1,549
19	Public Service Enterprise Group, Inc.	4,173	44	Western Resources, Inc.	1,431
20	GPU Inc.	3,686	45	OGE Energy Corp.	1,262
21	Central & South West Corp.	3,524	46	Sierra Pacific Resources	1,237
22	Pacificorp *	3,292	47	SCANA Corp.	1,226
23	Ameren Corp.	3,288	48	TECO Energy, Inc.	1,200
24	Niagara Mohawk Holdings Inc.	3,248	49	NiSource Inc.	1,121
25	Carolina Power & LightCo.	3,139	50	DQE	1,094

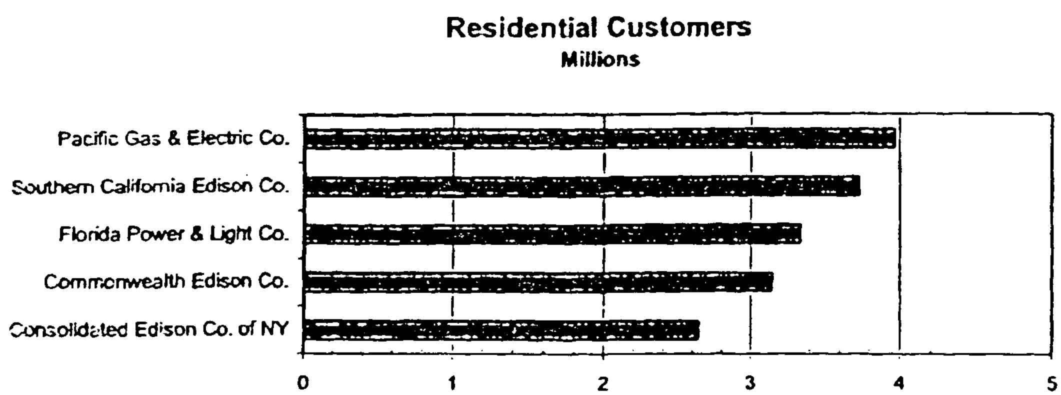
* As of March 31, 2000.

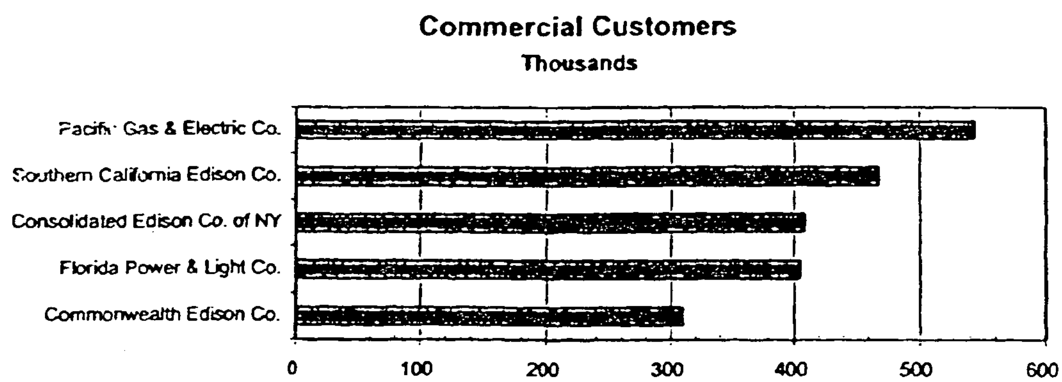
SECTION II

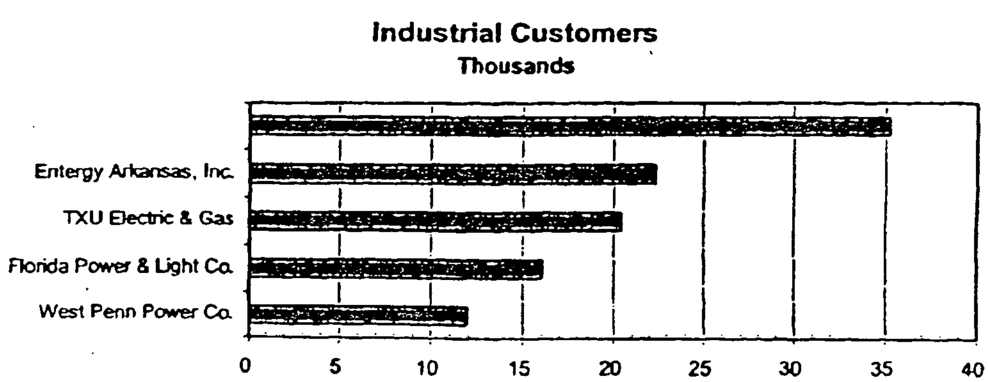
Rankings of Operating Companies by Ultimate Customers

TOP 5 OPERATING COMPANIES BY 1999 ULTIMATE CUSTOMERS

By Class of Service







886

DOE002-0896

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

TOTAL ULTIMATE CUSTOMERS

Average for Year - 1999

Rank	Company Name	Customers	Rank	Company Name	Customers
1	Pacific Gas and Electric Co.	4,535,909	26	Connecticut Light and Power Co., The	1,120,816
2	Southern California Edison Co.	4,213,562	27	Wisconsin Electric Power Co.	995,876
3	Florida Power & Light Co.	3,756,012	28	Jersey Central Power & Light Co.	989,126
4	Commonwealth Edison Co.	3,475,519	29	Ohio Edison Co.	982,772
5	Consolidated Edison Co. of New York, Inc	3,054,693	30	Massachusetts Electric Co.	981,469
6	TXU Electric Co.	2,537,010	31	Puget Sound Energy	899,902
7	Detroit Edison Co.	2,078,607	32	Appalachian Power Co.	892,748
8	Virginia Electric and Power Co.	2,047,938	33	New York State Electric & Gas Corp.	813,137
9	Duke Power.	2,022,835	34	Arizona Public Service Co.	806,569
10	Public Service Electric and Gas Co.	1,991,609	35	Cleveland Electric Illuminating Co., The	742,357
11	Georgia Power Co.	1,854,311	36	Portland General Electric Co.	714,130
12	Consumers Energy	1,651,437	37	OG&E Electric Services	697,939
13	Reliant Energy HL&P	1,645,552	38	PSI Energy, Inc.	696,330
14	Niagara Mohawk Power Corp.	1,579,090	39	Potomac Electric Power Co.	696,243
15	PacifiCorp	1,449,207	40	Ohio Power Co.	585,577
16	Florida Power Corp.	1,371,188	41	Boston Edison Co.	676,915
17	Alabama Power Co.	1,303,541	42	Entergy Gulf States, Inc.	664,043
18	Northern States Power Co. - MN	1,281,491	43	West Penn Power Co.	662,551
19	PECO Energy Co.	1,256,756	44	Central Power and Light Co.	661,105
20	PP&L, Inc.	1,214,301	45	MidAmerican Energy Co.	658,165
21	Carolina Power & Light Co.	1,199,456	46	Columbus Southern Power Co.	645,491
22	Public Service Co. of Colorado	1,194,847	47	Entergy Arkansas, Inc.	637,244
23	San Diego Gas & Electric Co.	1,184,844	48	Entergy Louisiana, Inc.	634,997
24	AmerenUE	1,164,127	49	Cincinnati Gas & Electric Co.	632,452
25	Baltimore Gas & Electric Co.	1,126,035	50	Nevada Power Co.	566,675

RESIDENTIAL CUSTOMERS

Average for Year - 1999

Rank	Company Name	Residential Customers	Rank	Company Name	Residential Customers
1	Pacific Gas & Electric Co.	3,972,257	26	Public Service Co. of Colorado	981,590
2	Southern California Edison Co.	3,732,780	27	Wisconsin Electric Power Co.	897,333
3	Florida Power & Light Co.	3,332,425	28	Ohio Edison Co.	879,302
4	Commonwealth Edison Co.	3,145,712	29	Jersey Central Power & Light Co.	878,134
5	Consolidated Edison Co. of NY, Inc.	2,642,102	30	Massachusetts Electric Co.	872,636
6	TXU Electric Co.	2,236,743	31	Puget Sound Energy, Inc.	797,421
7	Detroit Edison Co.	1,893,736	32	Appalachian Power Co.	770,390
8	Virginia Electric & Power Co.	1,821,399	33	New York State Electric & Gas Corp.	719,833
9	Duke Power	1,722,109	34	Arizona Public Service Co.	716,638
10	Public Service Electric & Gas Co.	1,720,036	35	Cleveland Electric Illuminating Co.	667,670
11	Georgia Power Co.	1,616,204	36	Portland General Electric Co.	627,396
12	Consumers Energy	1,457,459	37	Potomac Electric Power Co.	624,802
13	Reliant Energy HL&P	1,443,188	38	PSI Energy Inc.	609,000
14	Niagara Mohawk Power Corp.	1,425,094	39	OG&E Electric Services	599,702
15	PacifiCorp	1,239,072	40	Ohio Power Co.	592,824
16	Florida Power Corp.	1,208,739	41	Boston Edison Co.	584,795
17	PECO Energy Co.	1,146,199	42	West Penn Power Co.	580,230
18	Northern States Power Co.-MN	1,129,028	43	Entergy Gulf States, Inc.	579,099
19	Alabama Power Co.	1,112,007	44	Columbus Southern Power Co.	579,094
20	PP&L, Inc.	1,082,900	45	MidAmerican Energy Co.	569,824
21	San Diego Gas & Electric Co.	1,061,008	46	Central Power & Light Co.	563,217
22	Connecticut Light & Power Co.	1,022,005	47	Cincinnati Gas & Electric Co.	562,920
23	AmerenUE	1,015,222	48	Entergy Louisiana, Inc.	555,754
24	Baltimore Gas & Electric Co.	1,014,380	49	Entergy Arkansas, Inc.	541,575
25	Carolina Power & Light Co.	1,009,694	50	Nevada Power Co.	499,074

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

COMMERCIAL CUSTOMERS

Average for Year - 1999

Rank	Company Name	Commercial Customers	Rank	Company Name	Commercial Customers
1	Pacific Gas & Electric Co.	544,009	26	Baltimore Gas & Electric Co.	106,990
2	Southern California Edison Co.	468,784	27	Jersey Central Power & Light Co.	106,371
3	Consolidated Edison Co. of NY, Inc.	407,952	28	Massachusetts Electric Co.	103,939
4	Florida Power & Light Co.	404,944	29	Ohio Edison Co.	97,680
5	Commonwealth Edison Co.	309,828	30	Puget Sound Energy, Inc.	96,769
6	Duke Power	282,248	31	Wisconsin Electric Power Co.	95,964
7	Public Service Electric & Gas Co.	254,328	32	Connecticut Light & Power Co.	92,046
8	TXU Electric & Gas	248,544	33	Central Power & Light Co.	88,184
9	Georgia Power Co.	225,892	34	Boston Edison Co.	87,639
10	Reliant Energy HL&P	200,517	35	Portland General Electric Co.	85,870
11	Virginia Electric & Power Co.	198,154	36	Arizona Public Service Co.	85,071
12	Alabama Power Co.	185,851	37	PSI Energy Inc.	82,365
13	Consumers Energy	182,955	38	Ohio Power Co.	82,313
14	Carolina Power & Light Co.	181,975	39	New York State Electric & Gas Corp.	79,432
15	Detroit Edison Co.	181,893	40	OG&E Electric Services	77,876
16	PacifiCorp	170,315	41	MidAmerican Energy Co.	76,335
17	Niagara Mohawk Power Corp.	149,108	42	Entergy Gulf States, Inc.	73,037
18	AmerenUE	141,664	43	Entergy Arkansas, Inc.	72,844
19	Florida Power Corp.	140,313	44	South Carolina Electric & Gas Co.	72,048
20	Northern States Power Co. - MN	138,660	45	Potomac Electric Power Co.	71,280
21	Public Service Co. of Colorado	129,212	46	Kentucky Utilities Co.	70,455
22	PP&L, Inc.	126,100	47	West Penn Power Co.	69,841
23	San Diego Gas & Electric Co.	121,838	48	Cleveland Electric Illuminating Co.	69,200
24	Appalachian Power Co.	111,675	49	Entergy Louisiana, Inc.	67,051
25	PECO Energy Co.	108,131	50	Nevada Power Co.	66,477

INDUSTRIAL CUSTOMERS

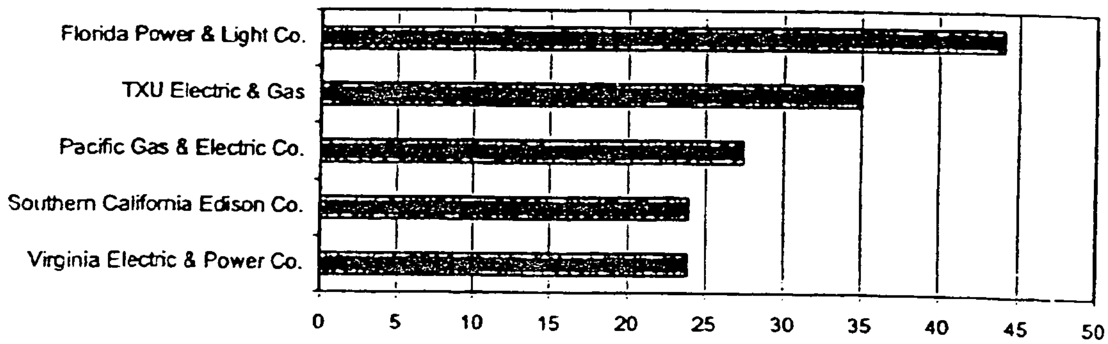
Average for Year - 1999

Rank	Company Name	Industrial Customers	Rank	Company Name	Industrial Customers
1	PacifiCorp	35,240	26	Public Service Co. of Oklahoma	4,902
2	Entergy Arkansas, Inc.	22,356	27	Baltimore Gas & Electric Co.	4,565
3	TXU Electric & Gas	20,436	28	PP&L, Inc.	4,500
4	Florida Power & Light Co.	16,042	29	Ohio Edison Co.	4,378
5	West Penn Power Co.	11,963	30	Appalachian Power Co.	4,322
6	Consumers Energy	9,196	31	Puget Sound Energy, Inc.	4,224
7	Georgia Power Co.	9,187	32	Southern California Edison Co.	4,176
8	OG&E Electric Services	8,961	33	Massachusetts Electric Co.	4,167
9	Public Service Electric & Gas Co.	8,940	34	Indianapolis Power & Light Co.	4,086
10	Entergy Gulf States, Inc.	8,745	35	Connecticut Light & Power Co.	3,987
11	Duke Power	8,672	36	Arizona Public Service Co.	3,943
12	Northern States Power Co. - MN	8,561	37	Kansas Gas and Electric Co.	3,503
13	Monongahela Power Co.	8,024	38	PSI Energy Inc.	3,479
14	Ohio Power Co.	7,856	39	Montana Power Co.	3,372
15	Southwestern Public Service Co.	7,406	40	Entergy Mississippi, Inc.	3,203
16	Entergy Louisiana, Inc.	6,946	41	Jersey Central Power & Light Co.	2,981
17	AmerenUE	5,664	42	Public Service Co. of New Hampshire	2,896
18	Southwestern Electric Power Co.	5,609	43	Columbus Southern Power Co.	2,855
19	West Texas Utilities Co.	5,499	44	Northern Indiana Public Service Co.	2,699
20	Indiana Michigan Power Co.	5,431	45	Florida Power Corp.	2,620
21	Central Power & Light Co.	5,335	46	Cincinnati Gas & Electric Co.	2,610
22	Cleveland Electric Illuminating Co.	5,271	47	Central Maine Power Co.	2,459
23	Potomac Edison Co.	5,172	48	New York State Electric & Gas Corp.	2,441
24	Carolina Power & Light Co.	5,041	49	Kansas City Power & Light Co.	2,381
25	Alabama Power Co.	4,982	50	Pennsylvania Electric Co.	2,232

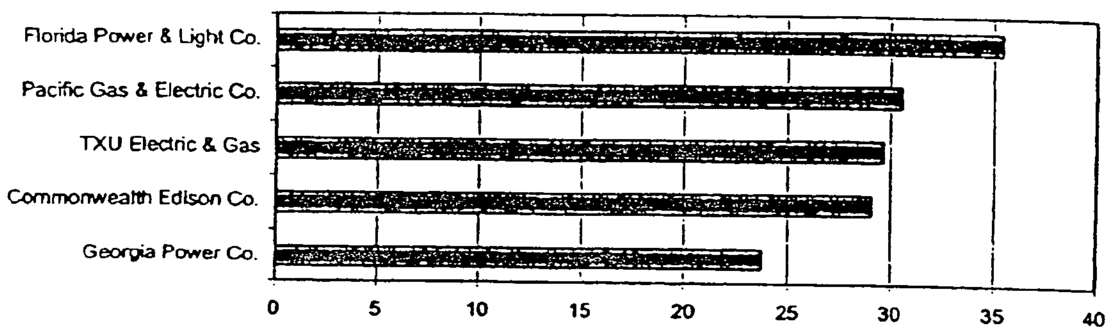
SECTION III
Rankings of Operating Companies by Sales to Ultimate Customers

TOP 5 OPERATING COMPANIES BY 1999 SALES TO ULTIMATE CUSTOMERS
By Class of Service

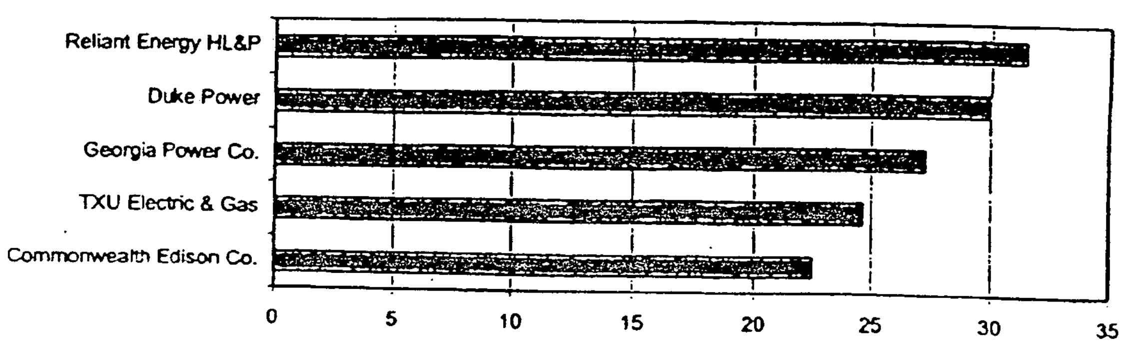
Residential Sales
Billions of Kilowatthours



Commercial Sales
Billions of Kilowatthours



Industrial Sales
Billions of Kilowatthours



TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

SALES TO ULTIMATE CUSTOMERS
Year - 1999

Rank	Company Name	MWh Sales	Rank	Company Name	MWh Sa
1	TXU Electric & Gas	95,927,336	26	Wisconsin Electric Power Co.	26,877,3
2	Florida Power & Light Co.	84,450,082	27	PSI Energy, Inc.	26,080,7
3	Commonwealth Edison Co.	83,500,597	28	Ohio Edison Co.	24,946,7
4	Duke Power	74,109,763	29	Potomac Electric Power Co.	24,209,2
5	Georgia Power Co.	70,972,000	30	PECO Energy Co.	23,593,6
6	Pacific Gas and Electric Co.	70,186,749	31	PP&L, Inc.	23,397,0
7	Reliant Energy HL&P	69,374,552	32	Public Service Co. of Colorado	23,337,6
8	Southern California Edison Co.	67,206,530	33	Connecticut Light and Power Co.	22,315,4
9	Virginia Electric and Power Co.	65,826,104	34	OG&E Electric Services	21,916,8
10	Alabama Power Co.	50,157,204	35	Central Power and Light Co.	21,303,6
11	Detroit Edison Co.	49,822,240	36	Puget Sound Energy	21,292,0
12	PacifiCorp	46,605,155	37	Arizona Public Service Co.	20,961,8
13	Public Service Electric and Gas Co.	40,289,444	38	Cincinnati Gas & Electric Co.	20,070,8
14	Carolina Power & Light Co.	40,217,290	39	Cleveland Electric Illuminating Co.	20,021,6
15	Consumers Energy	35,754,796	40	Portland General Electric Co.	19,258,9
16	Entergy Gulf States, Inc.	34,347,913	41	Jersey Central Power & Light Co.	18,951,1
17	Niagara Mohawk Power Corp.	33,756,106	42	South Carolina Electric & Gas Co.	18,878,8
18	AmerenUE	33,565,723	43	Entergy Arkansas, Inc.	18,663,6
19	Florida Power Corp.	33,441,029	44	Indiana Michigan Power Co.	18,339,8
20	Consolidated Edison Co. of New York, Inc	32,630,506	45	Illinois Power Co.	18,215,4
21	Ohio Power Co.	31,982,889	46	West Penn Power Co.	17,281,5
22	Northern States Power Co. - MN	31,645,688	47	Columbus Southern Power Co.	16,435,0
23	Baltimore Gas & Electric Co.	29,264,078	48	Kentucky Utilities Co.	16,307,5
24	Entergy Louisiana, Inc.	29,095,658	49	Southwestern Electric Power Co.	16,049,2
25	Appalachian Power Co.	27,933,324	50	MidAmerican Energy Co.	16,007,3

SALES TO RESIDENTIAL CUSTOMERS
Year - 1999

Rank	Company Name	Residential MWh Sales	Rank	Company Name	Resident MWh Sal
1	Florida Power & Light Co.	44,108,106	26	Entergy Gulf States, Inc.	8,928,64
2	TXU Electric & Gas	35,081,048	27	Arizona Public Service Co.	8,774,82
3	Pacific Gas & Electric Co.	27,429,734	28	Northern States Power Co. - MN	8,642,41
4	Southern California Edison Co.	23,976,071	29	Entergy Louisiana, Inc.	8,354,19
5	Virginia Electric & Power Co.	23,933,786	30	Ohio Edison Co.	8,122,41
6	Commonwealth Edison Co.	23,715,724	31	Jersey Central Power & Light Co.	7,973,87
7	Duke Power	22,032,753	32	PSI Energy Inc.	7,871,76
8	Reliant Energy HL&P	21,144,483	33	OG&E Electric Services	7,508,88
9	Georgia Power Co.	19,404,709	34	Portland General Electric Co.	7,404,37
10	Florida Power Corp.	16,244,772	35	Wisconsin Electric Power Co.	7,346,84
11	Alabama Power Co.	15,699,081	36	Central Power & Light Co.	7,247,62
12	Detroit Edison Co.	14,064,096	37	Public Service Co. of Colorado	7,052,92
13	Carolina Power & Light Co.	13,318,127	38	Potomac Electric Power Co.	7,013,63
14	PacifiCorp	13,032,079	39	Tampa Electric Co.	6,967,17
15	AmerenUE	11,872,621	40	Cincinnati Gas & Electric Co.	6,833,94
16	Consolidated Edison Co. of NY, Inc.	11,854,996	41	Ohio Power Co.	6,546,13
17	Public Service Electric & Gas Co.	11,747,256	42	Entergy Arkansas, Inc.	6,492,92
18	Consumers Energy	11,447,338	43	San Diego Gas & Electric Co.	6,327,48
19	PP&L, Inc.	11,381,000	44	South Carolina Electric & Gas Co.	6,268,55
20	Baltimore Gas & Electric Co.	11,349,276	45	Massachusetts Electric Co.	6,251,88
21	Appalachian Power Co.	10,394,478	46	Nevada Power Co.	6,134,66
22	Niagara Mohawk Power Corp.	10,193,922	47	Columbus Southern Power Co.	6,112,87
23	Puget Sound Energy, Inc.	9,787,382	48	West Penn Power Co.	5,942,06
24	PECO Energy Co.	9,649,013	49	Kentucky Utilities Co.	5,447,34
25	Connecticut Light & Power Co.	9,070,738	50	Indiana Michigan Power Co.	5,351,39

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

SALES TO COMMERCIAL CUSTOMERS

Year - 1999

Rank	Company Name	Commercial MWh Sales	Rank	Company Name	Commercial MWh Sales
1	Florida Power & Light Co.	35,456,942	26	Jersey Central Power & Light Co.	7,618,222
2	Pacific Gas & Electric Co.	30,570,948	27	Boston Edison Co.	7,484,619
3	TXU Electric & Gas	29,673,933	28	Puget Sound Energy, Inc.	7,461,482
4	Commonwealth Edison Co.	29,124,844	29	Entergy Gulf States, Inc.	7,310,108
5	Georgia Power Co.	23,715,486	30	Portland General Electric Co.	7,287,401
6	Southern California Edison Co.	22,812,150	31	Ohio Edison Co.	6,946,794
7	Duke Power	21,910,912	32	Columbus Southern Power Co.	6,683,121
8	Virginia Electric & Power Co.	21,760,428	33	PSI Energy Inc.	6,653,941
9	Public Service Electric & Gas Co.	19,932,648	34	Cleveland Electric Illuminating Co.	6,508,752
10	Detroit Edison Co.	19,546,640	35	PP&L, Inc.	6,313,000
11	Consolidated Edison Co. of NY Inc.	19,337,946	36	San Diego Gas & Electric Co.	6,283,848
12	Reliant Energy HL&P	16,615,979	37	Kansas City Power & Light Co.	6,260,085
13	Potomac Electric Power Co.	15,889,711	38	Massachusetts Electric Co.	6,105,112
14	Baltimore Gas & Electric Co.	13,194,090	39	Appalachian Power Co.	6,092,792
15	AmerenUE	12,682,640	40	South Carolina Electric & Gas Co.	5,952,030
16	PacifiCorp	12,676,071	41	Cincinnati Gas & Electric Co.	5,392,044
17	Alabama Power Co.	12,314,085	42	OG&E Electric Services	5,363,636
18	Niagara Mohawk Power Corp.	11,871,169	43	Tampa Electric Co.	5,336,395
19	Public Service Co. of Colorado	11,436,253	44	Central Power & Light Co.	5,255,798
20	Carolina Power & Light Co.	11,073,845	45	Entergy Louisiana, Inc.	5,221,419
21	Consumers Energy	10,748,734	46	Northern States Power Co.-MN	5,163,084
22	Florida Power Corp.	10,326,848	47	Public Service Co. of Oklahoma	5,056,916
23	Arizona Public Service Co.	9,431,119	48	Ohio Power Co.	5,050,789
24	Connecticut Light & Power Co.	8,973,405	49	Entergy Arkansas, Inc.	4,880,194
25	Wisconsin Electric Power Co.	8,028,191	50	Idaho Power Co.	4,870,063

SALES TO INDUSTRIAL CUSTOMERS

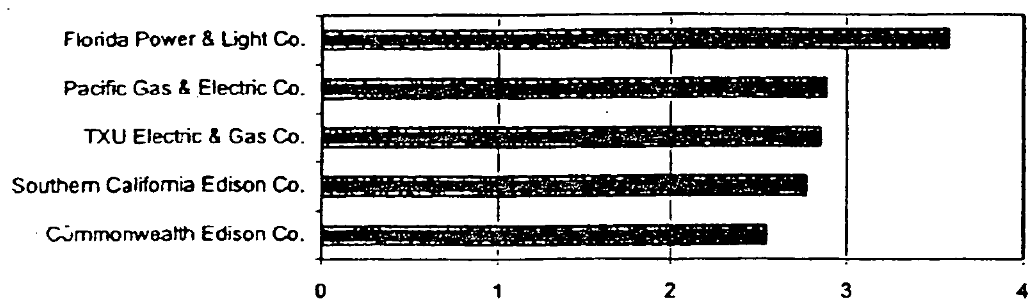
Year - 1999

Rank	Company Name	Industrial MWh Sales	Rank	Company Name	Industrial MWh Sales
1	Reliant Energy HL&P	31,480,606	26	Illinois Power Co.	8,721,860
2	Duke Power	29,878,386	27	PECO Energy Co.	8,645,492
3	Georgia Power Co.	27,300,355	28	Indiana Michigan Power Co.	8,236,177
4	TXU Electric & Gas	24,671,536	29	Public Service Electric & Gas Co.	8,229,498
5	Commonwealth Edison Co.	22,473,975	30	Central Power & Light Co.	8,219,415
6	Alabama Power Co.	21,942,889	31	Cleveland Electric Illuminating Co.	8,068,911
7	Ohio Power Co.	20,303,285	32	West Penn Power Co.	7,727,269
8	PacifiCorp	20,248,263	33	Southwestern Public Service Co.	7,315,683
9	Southern California Edison Co.	19,707,374	34	Indianapolis Power & Light Co.	7,253,760
10	Entergy Gulf States, Inc.	17,684,463	35	Entergy Arkansas, Inc.	7,053,935
11	Northern States Power Co.-MN	17,555,092	36	Electric Energy Inc.	7,013,929
12	Detroit Edison Co.	15,863,779	37	Southwestern Electric Power Co.	6,807,093
13	Entergy Louisiana, Inc.	15,051,633	38	OG&E Electric Services	6,621,629
14	Carolina Power & Light Co.	14,472,827	39	Minnesota Power	6,435,924
15	Consumers Energy	13,339,546	40	Cincinnati Gas & Electric Co.	6,349,370
16	Pacific Gas & Electric Co.	11,595,419	41	MidAmerican Energy Co.	6,225,969
17	Niagara Mohawk Power Corp.	11,493,402	42	South Carolina Electric & Gas Co.	6,140,248
18	PSI Energy Inc.	11,488,756	43	Potomac Edison Co.	5,841,102
19	Wisconsin Electric Power Co.	11,333,561	44	Monongahela Power Co.	5,736,718
20	Virginia Electric & Power Co.	11,142,066	45	Kentucky Utilities Co.	5,663,094
21	Appalachian Power Co.	10,744,639	46	PP&L, Inc.	5,564,000
22	Ohio Valley Electric Corp.	9,805,889	47	Toledo Edison Co.	5,448,819
23	Ohio Edison Co.	9,732,421	48	Nevada Power Co.	5,445,560
24	Northern Indiana Public Service Co.	9,198,314	49	Alliant Energy/IES Utilities, Inc.	5,071,545
25	AmerenUE	8,872,434	50	Public Service Co. of Oklahoma	4,971,651

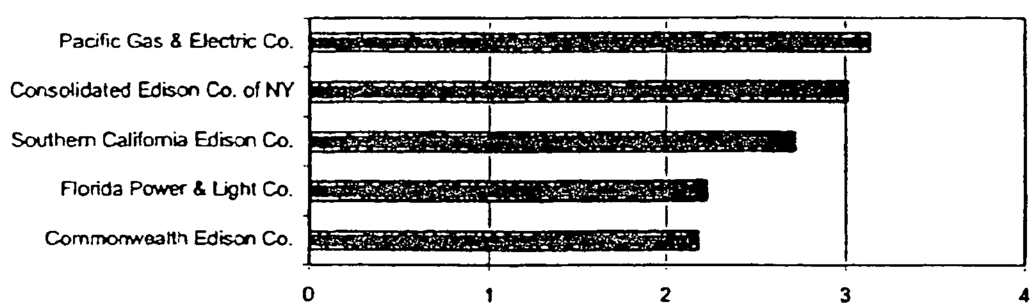
SECTION IV
Rankings of Operating Companies by Revenues From Sales to Ultimate Customers

TOP 5 OPERATING COMPANIES BY 1999 ELECTRIC OPERATING REVENUES
By Class of Service

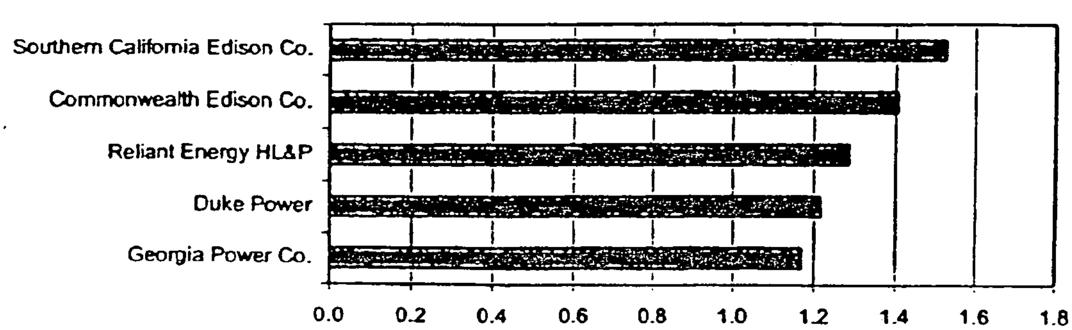
Residential Revenues
Billions of Dollars



Commercial Revenues
Billions of Dollars



Industrial Revenues
Billions of Dollars



892

DOE002-0902

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

REVENUES FROM SALES TO ULTIMATE CUSTOMERS
Year - 1999
Thousands of Dollars

Rank	Company Name	Total Revenues	Rank	Company Name	Total Revenues
1	Pacific Gas and Electric Co.	$6,785,994	26	Entergy Gulf States, Inc.	1,788,538
2	Southern California Edison Co.	6,692,164	27	Potomac Electric Power Co.	1,788,040
3	Commonwealth Edison Co.	6,175,861	28	PP&L, Inc.	1,761,778
4	TXU Electric & Gas	5,851,857	29	Cleveland Electric Illuminating Co.	1,743,148
5	Florida Power & Light Co.	5,830,116	30	Arizona Public Service Co.	1,716,236
6	Consolidated Edison Co. of NY, Inc.	4,500,992	31	Entergy Louisiana, Inc.	1,686,442
7	Reliant Energy HL&P	4,247,269	32	Wisconsin Electric Power Co.	1,550,536
8	Georgia Power Co.	4,129,088	33	New York State Electric & Gas Corp.	1,492,881
9	Duke Power	4,093,115	34	San Diego Gas & Electric Co.	1,415,141
10	Virginia Electric and Power Co.	3,989,073	35	Ohio Power Co.	1,393,498
11	Public Service Electric and Gas Co.	3,873,893	36	Public Service Co. of Colorado	1,375,599
12	Detroit Edison Co.	3,791,116	37	Boston Edison Co.	1,338,479
13	Niagara Mohawk Power Corp.	3,043,028	38	Central Power and Light Co.	1,306,971
14	Alabama Power Co.	2,811,117	39	Appalachian Power Co.	1,292,237
15	Carolina Power & Light Co.	2,519,348	40	Puget Sound Energy	1,269,286
16	Consumers Energy	2,498,266	41	Cincinnati Gas & Electric Co.	1,259,683
17	Florida Power Corp.	2,361,848	42	Massachusetts Electric Co.	1,259,428
18	Connecticut Light and Power Co.	2,190,813	43	PSI Energy, Inc.	1,251,012
19	PacifiCorp	2,172,555	44	OG&E Electric Services	1,191,079
20	Baltimore Gas & Electric Co.	2,118,845	45	Entergy Arkansas, Inc.	1,172,352
21	Ohio Edison Co.	2,093,478	46	Illinois Power Co.	1,138,822
22	PECO Energy Co.	2,066,833	47	South Carolina Electric & Gas Co.	1,124,176
23	AmerenUE	2,038,863	48	Tampa Electric Co.	1,100,103
24	Jersey Central Power & Light Co.	2,010,735	49	Columbus Southern Power Co.	1,062,454
25	Northern States Power Co. - MN	1,922,997	50	Indiana Michigan Power Co.	1,039,934

REVENUES FROM SALES TO RESIDENTIAL CUSTOMERS
Year - 1999
Thousands of Dollars

Rank	Company Name	Residential Revenues	Rank	Company Name	Residential Revenues
1	Florida Power & Light Co.	$3,345,390	26	PacifiCorp	799,574
2	Pacific Gas & Electric Co.	2,941,464	27	New York State Electric & Gas Corp.	736,368
3	Southern California Edison Co.	2,758,443	28	Northern States Power Co.-MN	682,784
4	TXU Electric & Gas	2,644,063	29	San Diego Gas & Electric Co.	662,437
5	Commonwealth Edison Co.	2,205,066	30	Entergy Louisiana, Inc.	620,146
6	Virginia Electric & Power Co.	1,892,318	31	Puget Sound Energy, Inc.	608,259
7	Consolidated Edison Co. of NY Inc.	1,881,808	32	Entergy Gulf States, Inc.	607,874
8	Reliant Energy HL&P	1,773,925	33	Cleveland Electric Illuminating Co.	598,957
9	Duke Power	1,596,132	34	Potomac Electric Power Co.	586,311
10	Georgia Power Co.	1,410,099	35	Appalachian Power Co.	578,162
11	Florida Power Corp.	1,394,869	36	Wisconsin Electric Power Co.	574,769
12	Public Service Electric & Gas Co.	1,319,499	37	Tampa Electric Co.	557,443
13	Detroit Edison Co.	1,300,433	38	Massachusetts Electric Co.	553,247
14	Niagara Mohawk Power Corp.	1,246,846	39	Central Power & Light Co.	540,452
15	Alabama Power Co.	1,145,646	40	Entergy Arkansas, Inc.	533,245
16	PECO Energy Co.	1,090,823	41	Cincinnati Gas & Electric Co.	529,476
17	Carolina Power & Light Co.	1,053,996	42	Public Service Co. of Colorado	529,463
18	Connecticut Light & Power Co.	1,014,215	43	OG&E Electric Services	515,299
19	Consumers Energy	976,006	44	PSI Energy Inc.	511,821
20	Baltimore Gas & Electric Co.	975,259	45	South Carolina Electric & Gas Co.	495,653
21	Jersey Central Power & Light Co.	923,345	46	Columbus Southern Power Co.	473,200
22	PP&L, Inc.	918,000	47	Boston Edison Co.	450,280
23	AmerenUE	871,211	48	Atlantic City Electric Co.	445,670
24	Ohio Edison Co.	854,746	49	Portland General Electric Co.	437,080
25	Arizona Public Service Co.	805,173	50	Ohio Power Co.	433,739

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

REVENUES FROM SALES TO COMMERCIAL CUSTOMERS

Year - 1999

Thousands of Dollars

Rank	Company Name	Commercial Revenues	Rank	Company Name	Commercial Revenues
1	Pacific Gas & Electric Co.	$3,051,519	26	Public Service Co. of Colorado	618,638
2	Consolidated Edison Co. of NY Inc.	2,471,560	27	Florida Power Corp.	617,586
3	Southern California Edison Co.	2,415,477	28	Cleveland Electric Illuminating Co.	617,170
4	Florida Power & Light Co.	2,218,382	29	San Diego Gas & Electric Co.	591,820
5	Commonwealth Edison Co.	2,196,069	30	Wisconsin Electric Power Co.	510,094
6	Public Service Electric & Gas Co.	1,888,209	31	PP&L, Inc.	497,000
7	TXU Electric & Gas	1,841,827	32	Puget Sound Energy, Inc.	474,240
8	Detroit Edison Co.	1,628,642	33	Massachusetts Electric Co.	472,607
9	Georgia Power Co.	1,527,880	34	PECO Energy Co.	449,324
10	Duke Power	1,272,801	35	Entergy Gulf States, Inc.	430,292
11	Virginia Electric & Power Co.	1,210,849	36	Columbus Southern Power Co.	420,612
12	Niagara Mohawk Power Corp.	1,195,701	37	Central Power & Light Co.	393,595
13	Reliant Energy HL&P	1,146,185	38	Kansas City Power & Light Co.	387,068
14	Potomac Electric Power Co.	1,121,287	39	Entergy Louisiana, Inc.	386,042
15	Baltimore Gas & Electric Co.	902,553	40	New York State Electric & Gas Corp.	383,818
16	Connecticut Light & Power Co.	850,729	41	Atlantic City Electric Co.	377,195
17	Alabama Power Co.	807,098	42	South Carolina Electric & Gas Co.	366,805
18	Jersey Central Power & Light Co.	795,105	43	Cincinnati Gas & Electric Co.	363,183
19	Consumers Energy	792,692	44	Portland General Electric Co.	355,615
20	AmerenUE	766,750	45	Tampa Electric Co.	345,503
21	Boston Edison Co.	736,865	46	Northern States Power Co. - MN	344,246
22	Arizona Public Service Co.	733,038	47	PSI Energy, Inc.	331,800
23	Carolina Power & Light Co.	704,603	48	Illinois Power Co.	329,223
24	PacifiCorp	663,012	49	Delmarva Power & Light Co.	323,901
25	Ohio Edison Co.	648,359	50	OG&E Electric Services	317,950

REVENUES FROM SALES TO INDUSTRIAL CUSTOMERS

Year - 1999

Thousands of Dollars

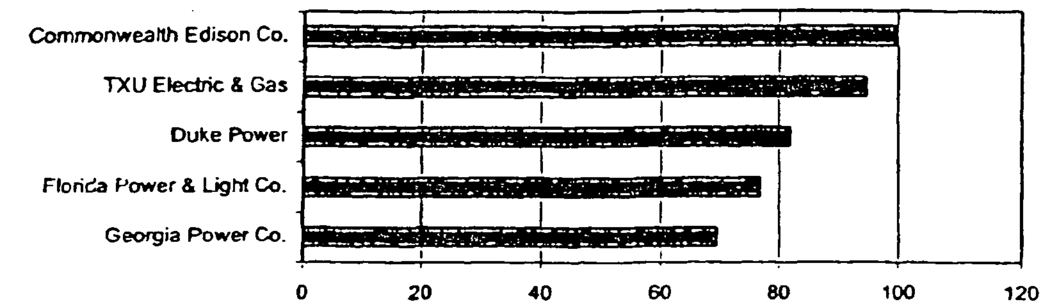
Rank	Company Name	Industrial Revenues	Rank	Company Name	Industrial Revenues
1	Southern California Edison Co.	$1,440,183	26	AmerenUE	385,538
2	Reliant Energy HL&P	1,299,899	27	Appalachian Power Co.	377,373
3	Commonwealth Edison Co.	1,290,926	28	Illinois Power Co.	368,288
4	Duke Power	1,198,634	29	Indiana Michigan Power Co.	364,606
5	Georgia Power Co.	1,143,002	30	Entergy Arkansas, Inc.	335,824
6	TXU Electric & Gas	938,191	31	Central Power & Light Co.	330,629
7	Northern States Power Co. - MN	868,700	32	PP&L, Inc.	329,000
8	Alabama Power Co.	843,090	33	Indianapolis Power & Light Co.	328,903
9	Detroit Edison Co.	815,149	34	West Penn Power Co.	320,349
10	Pacific Gas & Electric Co.	728,143	35	Connecticut Light & Power Co.	291,062
11	Entergy Gulf States, Inc.	718,778	36	Nevada Power Co.	290,410
12	Consumers Energy	705,026	37	Cincinnati Gas & Electric Co.	283,679
13	Carolina Power & Light Co.	685,054	38	Toledo Edison Co.	277,305
14	PacifiCorp	679,654	39	Jersey Central Power & Light Co.	271,954
15	Ohio Power Co.	674,998	40	MidAmerican Energy Co.	264,760
16	Entergy Louisiana, Inc.	646,517	41	Hawaiian Electric Co., Inc.	258,870
17	Public Service Electric & Gas Co.	607,755	42	Southwestern Electric Power Co.	255,038
18	Ohio Edison Co.	583,400	43	Dayton Power and Light Co.	242,410
19	Niagara Mohawk Power Corp.	550,463	44	OG&E Electric Services	239,934
20	Cleveland Electric Illuminating Co.	508,585	45	South Carolina Electric & Gas Co.	233,625
21	PECO Energy Co.	471,253	46	Minnesota Power	229,601
22	Wisconsin Electric Power Co.	451,164	47	Central Maine Power Co.	229,395
23	Virginia Electric & Power Co.	437,487	48	New York State Electric & Gas Corp.	222,426
24	Northern Indiana Public Service Co.	416,176	49	Southwestern Public Service Co.	222,258
25	PSI Energy Inc.	398,802	50	Massachusetts Electric Co.	220,891

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES
COMPARATIVE RANKING OF REVENUES, SALES AND ULTIMATE CUSTOMERS
Year - 1999

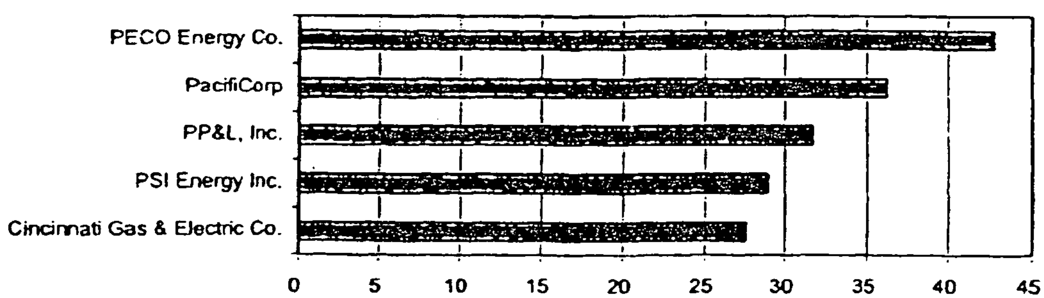
Company Name	Revenues	Rank	MWh Sales	Rank	Customers	Rank
Pacific Gas & Electric Co.	$6,785,994	1	70,186,749	6	4,535,909	1
Southern California Edison Co.	6,692,164	2	67,206,530	8	4,213,562	2
Commonwealth Edison Co.	6,175,861	3	83,500,597	3	3,475,519	4
TXU Electric & Gas	5,851,857	4	95,927,336	1	2,537,010	6
Florida Power & Light Co.	5,830,116	5	84,450,082	2	3,756,012	3
Consolidated Edison Co. of New York, Inc.	4,500,992	6	32,630,506	20	3,054,693	5
Reliant Energy HL&P	4,247,269	7	69,374,552	7	1,645,552	13
Georgia Power Co.	4,129,088	8	70,972,000	5	1,854,311	11
Duke Power	4,093,115	9	74,109,763	4	2,022,835	9
Virginia Electric & Power Co.	3,989,073	10	65,826,104	9	2,047,938	8
Public Service Electric & Gas Co.	3,873,893	11	40,289,444	13	1,991,609	10
Detroit Edison Co.	3,791,116	12	49,822,240	11	2,078,607	7
Niagara Mohawk Power Corp.	3,043,028	13	33,756,106	17	1,579,090	14
Alabama Power Co.	2,811,117	14	50,157,204	10	1,303,541	17
Carolina Power & Light Co.	2,519,348	15	40,217,290	14	1,199,456	21
Consumers Energy	2,498,266	16	35,754,796	15	1,651,437	12
Florida Power Corp.	2,361,848	17	33,441,029	19	1,371,188	16
Connecticut Light & Power Co., The	2,190,813	18	22,315,405	33	1,120,816	26
PacifiCorp	2,172,555	19	46,605,155	12	1,449,207	15
Baltimore Gas & Electric Co.	2,118,845	20	29,264,078	23	1,126,035	25
Ohio Edison Co.	2,093,478	21	24,946,704	28	982,772	29
PECO Energy Co.	2,066,833	22	23,593,639	30	1,256,756	19
AmerenUE	2,036,863	23	33,565,723	18	1,164,127	24
Jersey Central Power & Light Co.	2,010,735	24	18,951,186	41	989,126	28
Northern States Power Co. - MN	1,922,997	25	31,645,688	22	1,281,491	18
Entergy Gulf States, Inc.	1,788,538	26	34,347,913	16	664,043	42
Pepco	1,788,040	27	24,209,242	29	696,243	38
PP&L, Inc.	1,761,778	28	23,397,070	31	1,214,301	20
Cleveland Electric Illuminating Co., The	1,743,148	29	20,021,821	39	742,357	35
Arizona Public Service Co.	1,716,236	30	20,961,836	37	806,569	34
Entergy Louisiana, Inc.	1,686,442	31	29,095,658	24	634,997	48
Wisconsin Electric Power Co.	1,550,536	32	26,877,397	26	995,876	27
New York State Electric & Gas Corp.	1,492,881	33	13,192,379	62	813,137	33
San Diego Gas & Electric Co.	1,415,141	34	14,718,306	56	1,184,844	23
Ohio Power Co.	1,393,498	35	31,982,889	21	685,577	40
Public Service Co. of Colorado	1,375,599	36	23,337,607	32	1,194,847	22
Boston Edison Co.	1,338,479	37	12,864,155	63	676,915	41
Central Power & Light Co.	1,306,971	38	21,303,608	35	661,105	44
Appalachian Power Co.	1,292,237	39	27,933,324	25	892,748	32
Puget Sound Energy	1,269,286	40	21,292,035	36	899,902	31
Cincinnati Gas & Electric Co.	1,259,683	41	20,070,826	38	632,452	49
Massachusetts Electric Co.	1,259,428	42	15,657,428	52	981,469	30
PSI Energy, Inc.	1,251,012	43	26,080,752	27	696,330	37
OG&E Electric Services	1,191,079	44	21,916,854	34	697,939	36
Entergy Arkansas, Inc.	1,172,352	45	18,663,671	43	637,244	47
Illinois Power Co.	1,138,822	46	18,215,452	45	485,879	59
South Carolina Electric & Gas Co.	1,124,176	47	18,878,812	42	522,302	55
Tampa Electric Co.	1,100,103	48	15,804,958	51	543,661	53
Columbus Southern Power Co.	1,062,454	49	16,435,078	47	645,491	46
Indiana Michigan Power Co.	1,039,934	50	18,339,892	44	556,970	51

SECTION V
Additional Rankings of Operating Companies
1999 Data

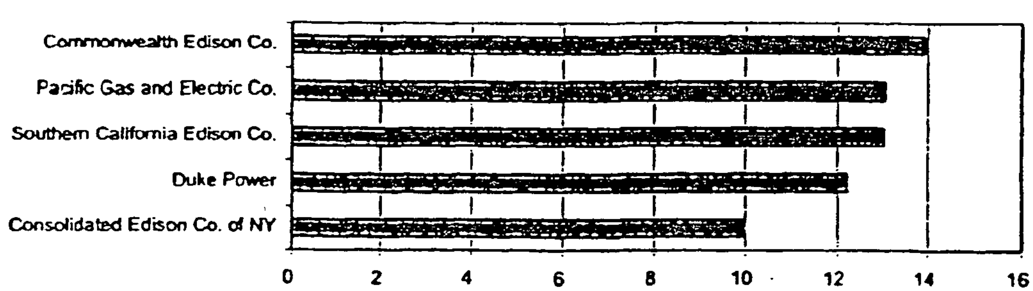
Net Generation
Millions of Megawatthours



Sales for Resale
Millions of Megawatthours



Electric Department Employees
Thousands



TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

NET GENERATION
Year - 1999
Megawatthours

Rank	Company Name	Generation	Rank	Company Name	Generation
1	Commonwealth Edison Co.	99,683,853	26	Wisconsin Electric Power Co.	28,398,952
2	TXU Electric & Gas	94,574,997	27	Cincinnati Gas & Electric Co.	27,112,651
3	Duke Power	81,869,260	28	Consumers Energy	25,329,352
4	Florida Power & Light Co.	76,839,241	29	Entergy Arkansas, Inc.	22,990,765
5	Georgia Power Co.	69,328,069	30	Potomac Electric Power Co.	22,806,586
6	Alabama Power Co.	62,794,354	31	Arizona Public Service Co.	22,484,845
7	Virginia Electric and Power Co.	62,269,185	32	Southwestern Public Service Co.	22,366,482
8	Reliant Energy HL&P	60,496,311	33	Central Power & Light Co.	22,165,977
9	PacifiCorp	57,541,406	34	Southwestern Electric Power Co.	22,145,646
10	Detroit Edison Co.	52,499,750	35	OG&E Electric Services	21,767,546
11	Carolina Power & Light Co.	51,665,192	36	Entergy Louisiana, Inc.	20,990,235
12	Ohio Power Co.	46,933,555	37	MidAmerican Energy Co.	19,757,510
13	PECO Energy Co.	42,054,432	38	Public Service Co of Colorado	19,707,204
14	PP&L, Inc.	39,470,951	39	Cleveland Electric Illuminating Co.	19,636,958
15	AmerenUE	37,579,419	40	Kentucky Utilities Co.	18,205,574
16	Public Service Electric & Gas Co.	34,568,422	41	Idaho Power Co.	17,917,936
17	Pacific Gas & Electric Co.	33,834,631	42	West Penn Power Co.	17,490,239
18	Northern States Power Co. - MN	33,724,560	43	South Carolina Electric & Gas Co.	17,055,438
19	Baltimore Gas & Electric Co.	32,683,655	44	Northern Indiana Public Service Co.	17,005,071
20	Southern California Edison Co.	32,383,136	45	Illinois Power Co.	16,792,644
21	PSI Energy Inc.	32,275,666	46	Dayton Power & Light Co.	16,728,107
22	Florida Power Corp.	32,140,176	47	Indianapolis Power & Light Co.	16,210,867
23	Appalachian Power Co.	31,819,012	48	Tampa Electric Co.	15,835,011
24	Entergy Gulf States, Inc.	29,291,355	49	Consolidated Edison Co. of NY, Inc.	15,549,062
25	Ohio Edison Co.	29,283,756	50	Kansas City Power & Light Co.	14,827,901

SALES FOR RESALE
Year - 1999
Megawatthours

Rank	Company Name	Sales for Resale	Rank	Company Name	Sales for Resale
1	PECO Energy Co.	42,741,425	26	Louisville Gas & Electric Co.	8,428,472
2	PacifiCorp	36,315,498	27	AEP Generating Co.	8,296,946
3	PP&L, Inc..	31,709,386	28	Southwestern Public Service Co.	7,599,535
4	PSI Energy Inc.	28,971,339	29	System Energy Resources Inc.	7,584,676
5	Cincinnati Gas & Electric Co.	27,566,718	30	Indiana Michigan Power Co.	7,580,517
6	Avista Corp.	19,777,887	31	Southwestern Electric Power Co.	7,521,517
7	Commonwealth Edison Co.	19,487,287	32	Duke Power	7,437,909
8	Ohio Power Co.	18,869,866	33	MidAmerican Energy Co.	7,167,449
9	Public Service Co of Colorado	17,997,230	34	Connecticut Light & Power Co.	6,941,382
10	Alabama Power Co.	17,119,732	35	AmerenUE	6,857,763
11	Arizona Public Service Co.	15,862,298	36	Georgia Power Co.	6,865,174
12	Carolina Power & Light Co.	14,541,871	37	Southern Electric Generating Co.	6,677,430
13	Portland General Electric Co.	14,384,519	38	Ohio Valley Electric Corp.	6,538,119
14	Entergy Arkansas, Inc.	12,460,205	39	Illinois Power Co.	6,526,265
15	KeySpan Generation LLC	12,142,079	40	Cleco Utility Group Inc.	6,438,974
16	Puget Sound Energy, Inc.	11,873,006	41	Montana Power Co.	6,322,424
17	Public Service Co. of New Mexico	11,171,621	42	Northern States Power Co. - MN	6,304,678
18	West Penn Power Co.	10,207,209	43	Ohio Edison Co.	6,124,176
19	Kentucky Utilities Co.	10,188,369	44	Idaho Power Co.	5,923,948
20	Appalachian Power Co.	9,804,230	45	Public Service Co. of New Hampshire	5,875,136
21	Virginia Electric & Power Co.	9,742,110	46	Detroit Edison Co.	5,702,232
22	Public Service Electric & Gas Co.	9,711,620	47	New York State Electric & Gas Corp.	5,525,137
23	Delmarva Power & Light Co.	9,157,794	48	AmerenCIPS	5,306,387
24	Consolidated Edison Co. of NY, Inc.	9,105,786	49	Tucson Electric Power Co.	5,224,235
25	Indiana-Kentucky Electric Corp.	8,487,027	50	Potomac Electric Power Co.	5,036,509

TOP 50 INVESTOR-OWNED ELECTRIC UTILITIES

ELECTRIC DEPARTMENT EMPLOYEES
Year - 1999

Rank	Company Name	Employees	Rank	Company Name	Employees
1	Commonwealth Edison Co.	13,932	26	Potomac Electric Power Co.	3,603
2	Pacific Gas and Electric Co.	13,073	27	Appalachian Power Co.	3,304
3	Southern California Edison Co.	13,040	28	South Carolina Electric & Gas Co.	3,287
4	Duke Power	12,242	29	Indiana Michigan Power Co.	3,119
5	Consolidated Edison Co. of NY, Inc.	9,926	30	Ohio Power Co.	3,084
6	Florida Power & Light Co.	9,676	31	Tampa Electric Co.	2,755
7	Virginia Electric and Power Co.	9,065	32	Portland General Electric Co.	2,605
8	Georgia Power Co.	8,607	33	Kansas City Power & Light Co.	2,485
9	Detroit Edison Co.	8,425	34	MidAmerican Energy Co.	2,460
10	TXU Electric & Gas Co.	7,868	35	New York State Electric & Gas Corp.	2,431
11	Pacificorp	7,574	36	Connecticut Light and Power Co.	2,348
12	Public Service Electric and Gas Co.	7,230	37	Duquesne Light Co.	2,142
13	Alabama Power Co.	6,701	38	Northern Indiana Public Service Co.	2,052
14	Reliant Energy HL&P	6,645	39	OG&E Electric Services	2,046
15	Carolina Power & Light Co.	6,333	40	San Diego Gas & Electric Co.	2,024
16	PP&L, Inc.	6,314	41	Alliant Utilities/IES Utilities Inc.	2,014
17	PECO Energy Co.	6,235	42	Boston Edison Co.	2,009
18	Niagara Mohawk Power Corp.	6,161	43	Wisconsin Public Service Corp.	1,979
19	Arizona Public Service Co.	5,959	44	PSI Energy, Inc.	1,903
20	Consumers Energy	5,730	45	Indianapolis Power & Light Co.	1,833
21	Baltimore Gas and Electric Co.	5,097	46	Ohio Edison Co.	1,811
22	Florida Power Corp.	4,766	47	Cincinnati Gas & Electric Co.	1,788
23	Northern States Power Co. - MN	4,764	48	Public Service Co. of Colorado	1,728
24	Wisconsin Electric Power Co.	4,525	49	Idaho Power Co.	1,720
25	AmerenUE	3,978	50	Puget Sound Energy, Inc.	1,718

TOP 10 INVESTOR-OWNED ELECTRIC UTILITIES

FOSSIL FUEL RECEIPTS

Year - 1999

Rank	Company Name	Coal (thousand short tons)	Rank	Company Name	Petro (thou ba
1	TXU Electric & Gas Co.	34,554	1	Florida Power & Light Co.	3
2	Georgia Power Co.	32,505	2	Hawaiian Electric Co., Inc.	1
3	PacifiCorp	30,773	3	Florida Power Corp.	1
4	Alabama Power Co.	24,398	4	Connecticut Light & Power Co.	[illegible]
5	Detroit Edison Co.	20,444	5	KeySpan Energy	[illegible]
6	Reliant Energy HL&P	20,059	6	Central Hudson Gas & Electric Corp.	[illegible]
7	AmerenUE	17,789	7	Entergy Mississippi Co.	[illegible]
8	PSI Energy Inc.	16,030	8	Consolidated Edison Co. of NY, Inc.	[illegible]
9	Duke Power	14,802	9	Potomac Electric Power Co.	[illegible]
10	Ohio Power Co.	14,504	10	Virginia Electric & Power Co.	[illegible]

Rank	Company Name	Gas (thousand Mcf)	Rank	Company Name	Petroleum (thou short
1	TXU Electric & Gas Co.	375,690	1	Pennsylvania Power Co.	
2	Reliant Energy HL&P	250,565	2	Northern Indiana Public Service Co.	
3	Entergy Gulf States Co.	193,162	3	Northern States Power Co.	
4	Florida Power & Light Co.	192,915	4	PP&L, Inc.	
5	Entergy Louisiana Co.	140,477	4	Utilicorp United Inc.	
6	Central Power & Light Co.	128,535	6	Wisconsin Electric Power Co.	
7	Public Service Co. of Oklahoma	79,118	7	Alliant Energy/Wisconsin Power & Light	
8	KeySpan Energy Corp.	78,994	8	Central Power & Light Co.	
9	Southwestern Public Service Co.	67,441	9	Indianapolis Power & Light Co.	
10	OG&E Electric Services	62,113	10	AmerenUE	

Rank	Company Name	Fuel Oil (thousand barrels)
1	Florida Power & Light Co.	37,403
2	Hawaiian Electric Co., Inc.	10,713
3	Florida Power Corp.	10,229
4	Connecticut Light & Power Co.	7,221
5	KeySpan Energy Corp.	6,874
6	Central Hudson Gas & Electric Corp.	5,912
7	Consolidated Edison Co. of NY, Inc.	4,949
8	Entergy Mississippi Co.	4,916
9	Potomac Electric Power Co.	3,865
10	Virginia Electric Power Co.	3,711

Note: Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.
Source: Federal Energy Regulatory Commission, FERC Form 423, Monthly Report Cost and Quality of Fuels for Electric Utility Plants.

SECTION VI

Miscellaneous

Investor-Owned Electric Utility Holding Companies and Systems

Investor-Owned Electric Utility Mergers and Name Changes

Glossary of Terms

INVESTOR-OWNED ELECTRIC UTILITY HOLDING COMPANIES AND SYSTEMS

AES Corporation (AES)
1001 North 19th Street
Arlington, VA 22209
(703) 522-1315
Central Illinois Light Company

Alaska Energy and Resources Company (AER)
5601 Tonsgard Court
Juneau, AK 99801-7201
(907) 780-2222
Alaska Electric Light and Power Company

Allegheny Energy, Inc. (AYE) *
10435 Downsville Pike
Hagerstown, MD 21740-1766
(301) 790-3400
Monongahela Power Company
Potomac Edison Company, The
West Penn Power Company
Note: All subsidiaries operate under the name Allegheny Power. Their legal names are listed above.

ALLETE (ALE)
30 West Superior Street
Duluth, MN 55802-2093
(218) 722-2641
Minnesota Power
Superior Water, Light and Power Company

Alliant Energy Corporation (LNT) *
222 West Washington Avenue
Madison, WI 53701-0192
(608) 252-3311
Alliant Energy/IES Utilities Inc.
Alliant Energy/Interstate Power Company
Alliant Energy/Wisconsin Power and Light Company
South Beloit Water, Gas and Electric Company

Ameren Corp. (AEE) *
One Ameren Plaza
1901 Chouteau Avenue
St. Louis, MO 63103-3003
(314) 621-3222
AmerenCIPS
AmerenUE

American Electric Power Company, Inc. (AEP) *
1 Riverside Plaza
Columbus, OH 43215-2373
(614) 223-1000
AEP Generating Company
Appalachian Power Company
Central Power & Light Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company
West Texas Utilities Company
Wheeling Power Company
Note: All subsidiaries operate under the name American Electric Power. Their legal names are listed above.

American States Water Company (AWR)
630 East Foothill Boulevard
San Dimas, CA 91773-1212
(909) 394-3600
Southern California Water Company

Central Vermont Public Service Corporation (CV)
77 Grove Street
Rutland, VT 05701-0608
(802) 773-2711
Connecticut Valley Electric Company, Inc.

CH Energy Group, Inc. (CNH)
284 South Avenue
Poughkeepsie, NY 12601-4823
(914) 452-2000
Central Hudson Gas & Electric Corporation

Cinergy Corp. (CIN) *
139 East Fourth Street
Cincinnati, OH 45202-4003
(513) 287-2644
Cincinnati Gas & Electric Company, The
Miami Power Corporation
Union Light, Heat & Power Company
West Harrison Gas & Electric Company
PSI Energy, Inc.

* Subject to the full regulatory scope of the Public Utility Holding Company Act of 1935 (PUHCA).

INVESTOR-OWNED ELECTRIC UTILITY HOLDING COMPANIES AND SYSTEMS, Cont'd.

Cleco Corporation (CNL)
2030 Donahue Ferry Road
Pineville, LA 71360-5226
(318) 484-7400
Cleco Utility Group, Inc.

CMS Energy Corporation (CMS)
Fairlane Plaza South
330 Town Center Drive
Dearborn, MI 48126
(313) 436-9261
Consumers Energy

Conectiv (CIV) *
800 King Street
Wilmington, DE 19899
(302) 429-3114
Atlantic City Electric Company
Deepwater Operating Company
Delmarva Power & Light Company

Consolidated Edison, Inc. (ED)
4 Irving Place
New York, NY 10003-3502
(212) 460-4600
Consolidated Edison Company of New York, Inc.
Orange and Rockland Utilities, Inc.
Pike County Light & Power Company
Rockland Electric Company

Constellation Energy Group, Inc. (CEG)
250 West Pratt Street
Baltimore, MD 21201
(410) 234-5685
Baltimore Gas and Electric Company

CP&L Energy, Inc.
411 Fayetteville Street Mall
Raleigh, NC 27601-1748
(919) 546-6111
Carolina Power & Light Company

Dominion Resources, Inc. (DRI)*
120 Tredegar Street
Richmond, VA 23219
(804) 819-2000
Dominion Virginia Power
Dominion North Carolina Power

DPL Inc. (DPL)
Courthouse Plaza, SW
Dayton, OH 45402
(937) 224-6000
Dayton Power and Light Company, The

DQE (DQE)
Cherrington Corp. Center
500 Cherrington Pkwy
Coraopolis, PA 15108-3184
(412) 262-4700
Duquesne Light Company

DTE Energy Company (DTE)
2000 Second Avenue
Detroit, MI 48226-1279
(313) 235-8000
Detroit Edison Company, The

Duke Energy Corporation (DUK)
422 South Church Street
Charlotte, NC 28201-1006
(704) 594-6200
Duke Power
Nantahala Power & Light Company

Dynegy (DYN)
1000 Louisiana
Houston, TX 77002
(713) 507-6400
Illinois Power Company

Edison International (EIX)
2244 Walnut Grove Avenue
Rosemead, CA 91770-0800
(626) 302-2222
Southern California Edison Company

Energy East Corporation (EAS) *
1 Commerce Plaza
Albany, NY 12260
(518) 434-3014
Central Maine Power Company
New York State Electric & Gas Corporation

Enron Corp. (ENE)
1400 Smith Street
Houston, TX 77002
(713) 853-6161
Portland General Electric Company

* Subject to the full regulatory scope of the Public Utility Holding Company Act of 1935 (PUHCA).

INVESTOR-OWNED ELECTRIC UTILITY HOLDING COMPANIES AND SYSTEMS, Cont'd.

Entergy Corporation (EC) *
639 Loyola Avenue
New Orleans, LA 70113-1704
(504) 529-5262
- Entergy Arkansas, Inc.
- Entergy Gulf States, Inc.
- Entergy Louisiana, Inc.
- Entergy Mississippi, Inc.
- Entergy New Orleans, Inc.
- System Energy Resources, Inc.

Exelon Corporation (EXE) *
One First National Plaza
10 South Dearborn Street
Chicago, IL 60690-3005
(312) 394-7399
- Commonwealth Edison Company
- Commonwealth Edison Company of Indiana
- PECO Energy Power Company
  - Susquehanna Power Company, The
- Susquehanna Electric Company, The

FirstEnergy Corp. (FE)
76 South Main
Akron, OH 44308-1890
(800) 736-3402
- Cleveland Electric Illuminating Company, The
- Ohio Edison Company
  - Pennsylvania Power Company
- Toledo Edison Company, The

Florida Progress Corporation (FPC)
One Progress Plaza
St. Petersburg, FL 33701
(727) 824-6400
- Florida Power Corporation

FPL Group, Inc. (FPL)
700 Universe Boulevard
Juno Beach, FL 33408-2683
(561) 694-4000
- Florida Power & Light Company

GPU, Inc. (GPU) *
300 Madison Avenue
Morristown, NJ 07962-1911
(973) 455-8200
- Jersey Central Power & Light Company
- Metropolitan Edison Company
  - York Haven Power Company
- Pennsylvania Electric Company

Note: GPU, Inc. operates under the name GPU. All subsidiaries operate under the name GPU Energy. Their legal names are listed above.

Hawaiian Electric Industries, Inc. (HEI)
900 Richards Street
Honolulu, HI 96813
(808) 543-5662
- Hawaiian Electric Company, Inc.
  - Hawaii Electric Light Company, Inc.
  - Maui Electric Company, Ltd.

IDACORP, Inc. (IDA)
1221 West Idaho Street
Boise, ID 83702-5627
(208) 388-2200
- Idaho Power Company

IPALCO Enterprises, Inc. (IPL)
25 Monument Circle
Indianapolis, IN 46206-1595
(317) 261-8261
- Indianapolis Power & Light Company

KeySpan Corporation (KSE)
One MetroTech Center
Brooklyn, NY 11201-3851
(718) 403-2000
- KeySpan Generation LLC

LG&E Energy Corporation (LGE)
220 West Main Street
Louisville, KY 40232
(502) 627-2000
- Kentucky Utilities Company
- Louisville Gas and Electric Company

MidAmerican Energy Holdings Company (MEC)
666 Grand Avenue
Des Moines, IA 50309
(515) 242-4300
- MidAmerican Energy Company

National Grid Group plc (NGG) *
National Grid House, Kirby Corner Road
Coventry CV4 8JY, England
011-44-1203-423616
- National Grid USA *
  - Granite State Electric Company
  - Massachusetts Electric Company
  - Montaup Electric Company
  - Nantucket Electric Company
  - Narragansett Electric Company, The
  - New England Electric Transmission Corporation
  - New England Hydro-Transmission Corporation
  - New England Hydro-Transmission Electric Co.
  - New England Power Company

* Subject to the full regulatory scope of the Public Utility Holding Company Act of 1935 (PUHCA).

INVESTOR-OWNED ELECTRIC UTILITY HOLDING COMPANIES AND SYSTEMS, Cont'd.

Niagara Mohawk Holdings Inc. (NMK)
300 Erie Boulevard West
Syracuse, NY 13202-4201
(315) 474-1511
Niagara Mohawk Power Corp.

NiSource, Inc. (NI)
801 East 86th Avenue
Merrillville, IN 46410
(219) 853-5200
Northern Indiana Public Service Company

Northeast Utilities (NU) *
174 Brush Hill Avenue
West Springfield, MA 01090-0010
(413) 785-5871
Connecticut Light and Power Company, The
Holyoke Water Power Company
Holyoke Power and Electric Company
Public Service Company of New Hampshire
Western Massachusetts Electric Company

NSTAR (NST)
800 Boylston Street
Boston, MA 02199-8003
(617) 424-2000
Boston Edison Company
Cambridge Electric Light Company
Canal Electric Company
Commonwealth Electric Company

OGE Energy Corp. (OGE)
321 North Harvey Avenue
Oklahoma City, OK 73102
(405) 553-3000
OG&E Electric Services

PG&E Corporation (PCG)
1 Market, Spear Tower
Suite 2400
San Francisco, CA 94105
(415) 267-7000
Pacific Gas & Electric Company

Pinnacle West Capital Corporation (PNW)
400 East Van Buren Street
Phoenix, AZ 85072
(602) 379-2616
Arizona Public Service Company

PPL Corporation (PPL)
Two North Ninth Street
Allentown, PA 18101-1179
(610) 774-5151
PPL Utilities

Public Service Enterprise Group, Inc. (PSEG)
80 Park Plaza
Newark, NJ 07102-4106
(973) 430-7000
Public Service Electric and Gas Company

Reliant Energy, Inc. (REI)
1111 Louisiana
Houston, TX 77002-5231
(713) 207-3000
Reliant Energy HL&P

RGS Energy Group Inc. (RGS)
89 East Avenue
Rochester, NY 14649-0001
(716) 771-4444
Rochester Gas and Electric Corporation

SCANA Corporation (SCG)
1426 Main Street
Columbia, SC 29201
(803) 217-9000
South Carolina Electric & Gas Company
South Carolina Generating Company, Inc.

ScottishPower Group (SPI) *
1 Atlantic Quay
Glasgow G2 8SP, Scotland
011-44-141-2488200
PacifiCorp

Sempra Energy (SRE)
101 Ash Street
San Diego, CA 92101-3906
(619) 696-2000
San Diego Gas & Electric Company

Sierra Pacific Resources (SPR)
6100 Neil Road
Reno, NV 89511-1132
(775) 834-4011
Nevada Power Company
Sierra Pacific Power Company

Southern Company, The (SO) *
270 Peachtree Street, NW
Atlanta, GA 30303
(404) 506-6526
Alabama Power Company
Georgia Power Company
Gulf Power Company
Mississippi Power Company
Savannah Electric and Power Company
Southern Electric Generating Company

*Subject to the full regulatory scope of the Public Utility Holding Company Act of 1935 (PUHCA).

INVESTOR-OWNED ELECTRIC UTILITY HOLDING COMPANIES AND SYSTEMS, Cont'd.

TECO Energy, Inc. (TE)
702 North Franklin Street
Tampa, FL 33602-4418
(813) 228-4111
Tampa Electric Company

TNP Enterprises, Inc. (TNP)
4100 International Plaza Tower Two
Fort Worth, TX 76109-4896
(817) 731-0099
Texas-New Mexico Power Company

Texas Utilities Company (TXU)
dba TXU Corp.
Energy Plaza, 1601 Bryan Street
Dallas, TX 75201-3411
(214) 812-4600
Southwestern Electric Service Company
TXU Electric & Gas

UIL Holdings Corporation (UIL)
157 Church Street
New Haven, CT 06506-0901
(203) 299-2000
United Illuminating Company, The

UGI Corporation (UGI)
460 North Gulph Road
King of Prussia, PA 19406
(610) 337-1000
UGI Utilities, Inc.

UniSource Energy Corporation (UNS)
220 West Sixth Street
Tucson, AZ 85701-1093
(520) 571-4000
Tucson Electric Power Company

UNITIL Corporation (UNT) *
Six Liberty Lane West
Hampton, NH 03842-1720
(603) 772-0775
Concord Electric Company
Exeter & Hampton Electric Company
Fitchburg Gas and Electric Light Company

Vectren, Inc. (VVC)
20 NW Fourth Street
Evansville, IN 47741-0001
(812) 465-5300
Southern Indiana Gas and Electric Company

Western Resources, Inc. (WRI)
818 South Kansas Avenue
Topeka, KS 66612-1217
(785) 575-6300
Kansas Gas and Electric Company

Wisconsin Energy Corporation (WEC)
P.O. Box 2949
Milwaukee, WI 53201-2949
(414) 221-2345
Edison Sault Electric Company
Wisconsin Electric Power Company

WPS Resources Corporation (WPS)
700 North Adams Street
Green Bay, WI 54307
(920) 433-1727
Upper Peninsula Power Company
Wisconsin Public Service Corporation

Xcel Energy Inc. (XEL) *
1225 17th Street
Denver, CO 80202-5533
(303) 571-7511
Cheyenne Light, Fuel and Power Company
Northern States Power Company
Northern States Power Company (WI)
Public Service Company of Colorado
Southwestern Public Service Company

*Subject to the full regulatory scope of the Public Utility Holding Company Act of 1935 (PUHCA).

INVESTOR-OWNED ELECTRIC UTILITY MERGERS AND COMPANY NAME CHANGES
October 1999 - October 2000

Company Name	Merged Into/Name Change*	Date
Blackstone Valley Electric Co.	Narragansett Electric Co.	04/19/00
CMP Group, Inc.	Energy East Corp.	09/01/00
Central and SouthWest Corp.	American Electric Power Co., Inc.	06/15/00
CILCORP Inc.	AES Corporation	10/18/99
Eastern Edison Co.	Massachusetts Electric Co.	04/19/00
Eastern Utilities Associates	National Grid USA	04/19/00
Illinova Corporation	Dynegy	02/01/00
Minnesota Power, Inc.	*ALLETE*	09/05/00
Newport Electric Co.	Narragansett Electric Co.	04/19/00
New Century Energies	Xcel Energy Inc.	08/21/00
New England Electric System (NEES)	National Grid USA	03/22/00
North Carolina Power Co.	*Dominion North Carolina Power*	08/28/00
PP&L Resources, Inc.	*PPL Corporation*	02/14/00
PP&L, Inc.	*PPL Utilities*	02/14/00
SIGCORP, Inc.	Vectren Corporation	03/31/00
Unicom Corporation	Exelon Corporation	10/20/00
Utilicorp United Inc. (West Virginia Power)	Allegheny Power	01/04/00
Virginia Electric and Power Co.	*Dominion Virginia Power*	08/28/00

*Italics indicate company name change only.

GLOSSARY OF TERMS

Assets (and Other Debits) Items of value owned by or owed to a business. Represents either a property right or value acquired, or an expenditure made which has created a property right or is properly applicable to the future. Utility assets include: Utility Plant, Other Property and Investments, Current and Accrued Assets, and Deferred Debits.

Average Number of Customers The arithmetic averages of month-end customers in each of 12 consecutive months. For those billed other than every month, the number of such customers is adjusted to a 12-month basis (e.g., for bi-monthly billing the number of customers billed, or counted, in each month is multiplied by two and the result averaged for the 12-month period).

Classes of Electric Service

Residential: A customer, sales, and revenue classification covering electric energy supplied for residential (household) purposes. The classification of an individual customer's account where the use is both residential and commercial is based on principal use.

Commercial and Industrial: (Small Light and Power, Large Light and Power) A customer, sales, and revenue classification covering energy supplied for commercial and industrial purposes, except that supplied under special contracts or agreements or service classifications applicable only to municipalities or divisions or agencies of federal or state

Railroads and Railways: A customer, sales, and revenue classification covering electric energy supplied to railroads and interurban and street railways for general railroad use, including the propulsion of cars or locomotives, where such energy is supplied under separate and distinct rate schedules.

Interdepartmental Sales: Kilowatthour sales of electric energy to other departments (gas, steam, water, etc.) and dollar value of such sales at tariff or other specified rates for the energy supplied.

Sales for Resale: (Other Electric Utilities) Sales of electric energy to other electric utilities or public authorities for resale purposes.

Combination Company A company which renders more than one type of utility service, such as electric and gas. If more than 95% of such a company's utility plant is devoted to one type of service, or more than 95% of its operating revenue is derived from one type of service, it is not classified as a combination company.

Customer (Electric) An individual, firm, organization, or other electric utility which purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer unless the consumptions are combined before the bill is calculated. *See also Ultimate Customers.*

Electric Utility Industry or Electric Utilities All enterprises engaged in the production and/or distribution of electricity for use by the public, including investor-owned electric utility companies; cooperatively-owned electric utilities; government-owned electric utilities (municipal systems, federal agencies, state projects, andd public power districts); and where the data are not separable, those industrial plants contributing to the public supply.

Generation, Electric The act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kilowatthours.

Gross The total amount of electric energy produced by the generating units in a generating station or stations measured at the generator terminals.

Net Gross generation less kilowatthours used at the generating station(s).

Holding Company, (Electric Utility) Usually means a Corporation (parent company) that directly or indirectly owns a majority or all of the voting securities of one or more electric utility companies which are located in the same or contiguous states. As most states do not permit a foreign utility company (i.e., one which operates in another state) to operate within their own boundaries, the holding company type of organization is used to bring into one family, consistent with state law, companies that can best be operated as part of an integrated utility system. *See also Holding Company, Registered*

Holding Company, Registered Under the Public Utility Holding Company Act of 1935 (PUHCA) unless an exemption is available, all holding companies whose subsidiaries are engaged in the electric utility business or in retail distribution of natural manufactured gas must register with the Securities and Exchange Commission (SEC) as a company that directly or indirectly owns 10% or more of the voting securities of a public utility. Once registered, a holding company (I) must limit the operations of each holding company system to a "single integrated public utility system" with only "such other businesses as are reasonably incidental or economically necessary or appropriate to the operations of [the]...system," and (ii) comply with various regulations regarding the financing and operation of the holding company system.

Holding Company, Exempt Unless the SEC finds that the exemption is detrimental to the public interest or the interests of investors or consumers, a utility holding company may be exempted from the provisions of PUHCA under certain conditions.

Investor-Owned Electric Utilities Those electric utilities organized as tax-paying businesses usually financed by the sale of securities in the free market, and whose properties are managed by representatives regularly elected by their shareholders. Investor-owned electric utilities, which may be owned by an individual proprietor or a small group of people, are usually corporations owned by the general public.

Operating Company Any company engaged in the production, transmission or distribution of electric energy. Usually excludes those which are cooperatively or municipally operated and federal/state power projects.

Operating Revenues The amounts billed by the utility for utility services rendered and for other services incidental thereto.

Ultimate Customers Those customers purchasing electricity for their own use and not for resale.

EEI Statistics Publications

Advance Release—2000 Edition Data for the Statistical Yearbook of the Electric Utility Industry/1999

Get your first look at 1999 electric utility industry data with EEI's *Advance Release – 2000 Edition*. This is the initial data collection charting 1999 electric utility operations and financial performance. Previewing year-end results in easy-to-read charts and tables, this release provides the most current data available on:

- Installed capacity by state and prime mover
- Generation by state and prime mover
- Fuel consumption
- Customers, sales, and revenues by state and customer class
- Revenue per kilowatthour by state and customer class
- Revenue and use per customer by state and customer class
- Combined balance sheets and income statements
- Long-term financing
- And more

Use these figures to get a head start on your analysis of 1999. EEI, 2000.

Item# 03-00-11-009
List Price: $90.00
EEI Member Price: $45.00

Capacity and Generation of Non-Utility Sources of Energy

The data is now available as special data reports. The summary tables containing capacity and generation by state, type of producer, fuel and industry class will be created for immediate delivery. You can also request custom data runs to meet your specific data needs. Order a single table or as many as you need with exactly the data you need…and no data that you don't need! Data are available for calendar years 1985 through 1998.

Give EEI a call and let's discuss your data needs! Call Peggy Suggs at 202-508-5572 or e-mail psuggs@eei.org

Catalogue of Investor-Owned Electric Utilities — 2000 Edition

The *Catalogue* is an essential reference that should be on the shelf of all energy professionals! Expanded and completely updated!

Your one-stop resource for:

- Who are the industry's players?
- Which companies have merged or changed names?
- Which companies are no longer in existence?
- Which companies are jointly owned?

You get complete IOU listings of:

- All operating companies (Organized by state)
- All holding companies and systems
- All jointly-owned and combination companies

Company information includes:

- Current company names, addresses and telephone numbers
- Revenues
- Rankings by sales, revenues, and customers
- Ultimate customers
- Megawatthour sales
- Mergers and acquisitions
- Power marketing affiliates of investor-owned electric utilities

This nuts-and-bolts directory is a basic reference that should be on the office shelf of everyone involved in the energy industry! Available as a print publication or as a PDF file. EEI, 2000.

FREE to EEI Utility Members – EEI Utility Members have FREE access to the *Catalogue* in EEI Member Net's Products and Services section at www.eei.org/member_net. Print copies can be purchased for an additional cost.

Print Format:
Item # 03-00-12-009
List Price: $95.00
EEI Associate Member Price: $45.00
EEI Utility Member Price: Free electronically in EEI Member Net, print copies are $45.00

PDF File:
Item #03-00-18-009
List Price: $75.00
EEI Associate Member Price: $25.00
A PDF file will be e-mailed to you within three days of receipt of payment.

Customized Statistical Reports

Customized computer runs for special information needs are available. Using any data element in the *Statistical Yearbook*, or *Capacity and Generation: Non-Utility Sources of Energy*, special reports can be created. Historical data is also available. Contact the EEI Statistics Department at (202) 508-5574.

Historical Statistics of the Electric Utility Industry through 1992

This comprehensive reference traces important operating and financial data as far back as 1902. Data are presented in tables that clearly show information and trends for both the investor-owned electric utilities and the total electric utility industry. Various categories make accessibility easy:

- Generating capacity
- Electric power supply
- Generation
- Fuel
- Energy
- Energy sales
- Customers
- Revenues
- Financial
- Economics
- And more

Tables sorted by state cover statistics from 1960 through 1992. Starting years for each series may vary depending on information availability. Data has been compiled from EEI's statistical questionnaires, the Federal government, and the private sector. Recommended for energy analysts, consultants, investors, students, and anyone interested in the electric utility industry. EEI, 1995.

Item # 11-95-01-009
List Price: $200.00
EEI Member Price: $100.00

Historical Statistics of the Electric Utility Industry through 1992 (Diskette)

Files are in standard LOTUS 1-2-3® format for easy retrieval and manipulation of tables. All information is identical to and appears in the same order as the book for easy reference. Full or partial installation may be chosen depending on available computer memory.

Diskette
Item # 11-95-03-009
List Price: $350.00
EEI Member Price: $175.00

Book and Diskette Set
Item #11-95-04-009
List Price: $395.00
EEI Member Price: $195.00

Rankings of Investor-Owned Electric Utilities—2000 Edition

Who are the major players in today's changing market place? This barometer of the investor-owned electric utility industry provides information on the top 50 utilities in several categories. Includes rankings on a holding-company basis by assets and by electric operating revenues; on an operating company basis by ultimate customer, sales to ultimate customers, and by revenues to ultimate customers. A comparative ranking, showing total revenues, customers, and sales – ranked by revenues – is also provided. Additional rankings include net generation, number of employees, total sales for resale, and fossil fuel receipts (top ten).

Additional holding company rankings include total operating revenues, market capitalization, and total employees. Useful for utilities, public service commissions, governmental agencies, energy consultants, and financial institutions, Rankings helps industry stakeholders with company-to-company comparisons. Available as a print publication or as a PDF file. EEI, 2000.

FREE to EEI Utility Members – EEI Utility Members have FREE access to the *Rankings of IOUs* in EEI Member Net's Products and Services section at www.eei.org/member_net. Print copies can be purchased for an additional cost.

Print Format
Item # 03-00-19-009
List Price: $95.00
EEI Associate Member Price: $45.00
EEI Utility Member Price: Free electronically in EEI Member Net, print copies are $45.00

PDF File
Item # 03-00-20-009
List Price: $75.00
EEI Associate Member Price: $25.00
A PDF file will be e-mailed to you upon receipt of payment.

Statistical Releases Package

Access comprehensive statistical information on the Internet with one easy order! EEI's *Statistical Release Package* provides continuous, accurate, and timely statistical data tracking the electric power industry. This Web-based data collection includes the latest *Statistical Yearbook of the Electric Utility Industry* and the *Advance Release of Data for the Statistical Yearbook*. Also included are annual subscriptions to the *Weekly Electric Output Report** and *StatMaps*.

• **Statistical Yearbook of the Electric Utility Industry** — The premier reference source for electric utility operations and financial performance statistics. (also available separately as a print publication or PDF file)

• **Advance Release** — A data preview for the annual *Statistical Yearbook*, including select tables and charts of the most current data available. Published each Spring. (also available separately as a print publication or PDF file)

• **Weekly Electric Output Report*** — Provides up-to-date electric output data for nine geographic areas and the total United States. Data are presented on a year-to-date and a 52 weeks-ended basis.

• **StatMaps** — Monthly statistics for the total electric utility industry on generation, sales, revenues and average cents per kWh expended on electricity. Annual data on customers by state are included as well. Provided in U.S. state map format, access to state and U.S. Census Bureau regional data is a few mouse clicks away.

EEI Utility Members have FREE access to this Web site through EEI Member Net's Products and Services section at www.eei.org/member_net.

EEI Associates and Non-members:

One rate for your entire site...or your whole corporation! Access the Statistical Release Package through EEI's Electronic Subscription Service "EEI Online." You can distribute EEI Online products to your own location—**for one low price.** No additional site license is required. (See Terms and Conditions when you subscribe.) Access for multiple locations is also available. Call for details.

Subscribe now!

Call 202-508-5005 to subscribe, or visit our web site at www.eei.org/7online. You will receive an ID and password to access your service within three business days after we receive your completed subscriber agreement form.

Annual Subscription Rates

List Price: $400.00

EEI Associate Members: $200.00

EEI Utility Members: FREE

**Weekly Electric Output is also available via fax. Call for details.*

Statistical Yearbook of the Electric Utility Industry – 2000 Edition

The premier reference source for electric utility operations and financial performance statistics. Data covers all areas of the electric utility industry, including cooperatively-owned, government-owned, and investor-owned utilities. The *Yearbook* provides the most current picture of the rapidly changing electric power industry. Includes national, regional, and state statistics in easy-to-read charts and tables for:

Operating Stats

- Installed capacity
- Average kilowatthour use
- Fuel use and type
- Consumption of fossil fuels
- Generation and supply
- Capacity, capability and peak load
- Sources of energy for generation
- Average delivered cost of fossil fuels
- Circuit miles of overhead lines

Financial Performance/Economic Statistics

- Sales, revenues, and customers
- Taxes
- Utility finance
- Income statements
- Long-term utility financing
- Balance sheets
- Common stock averages
- Average yields
- Construction expenditures

Data is collected from a variety of private and public sources. Other sources of energy are also included in these aggregate figures. Available as a print publication or a PDF file. EEI, 2000.

FREE to EEI Utility Members – EEI Utility Members have FREE access to the *Statistical Yearbook* as part of the *Statistical Release Package* in EEI Member Net's Products and Services section at www.eei.org/member_net. Print copies can be purchased for an additional cost.

Print Format

Item # 03-00-14-009

List Price: $450.00

EEI Associate Member Price: $225.00

EEI Utility Member Price: Free electronically in EEI Member Net, print copies are $225.00

PDF File

Item # 03-00-15-009

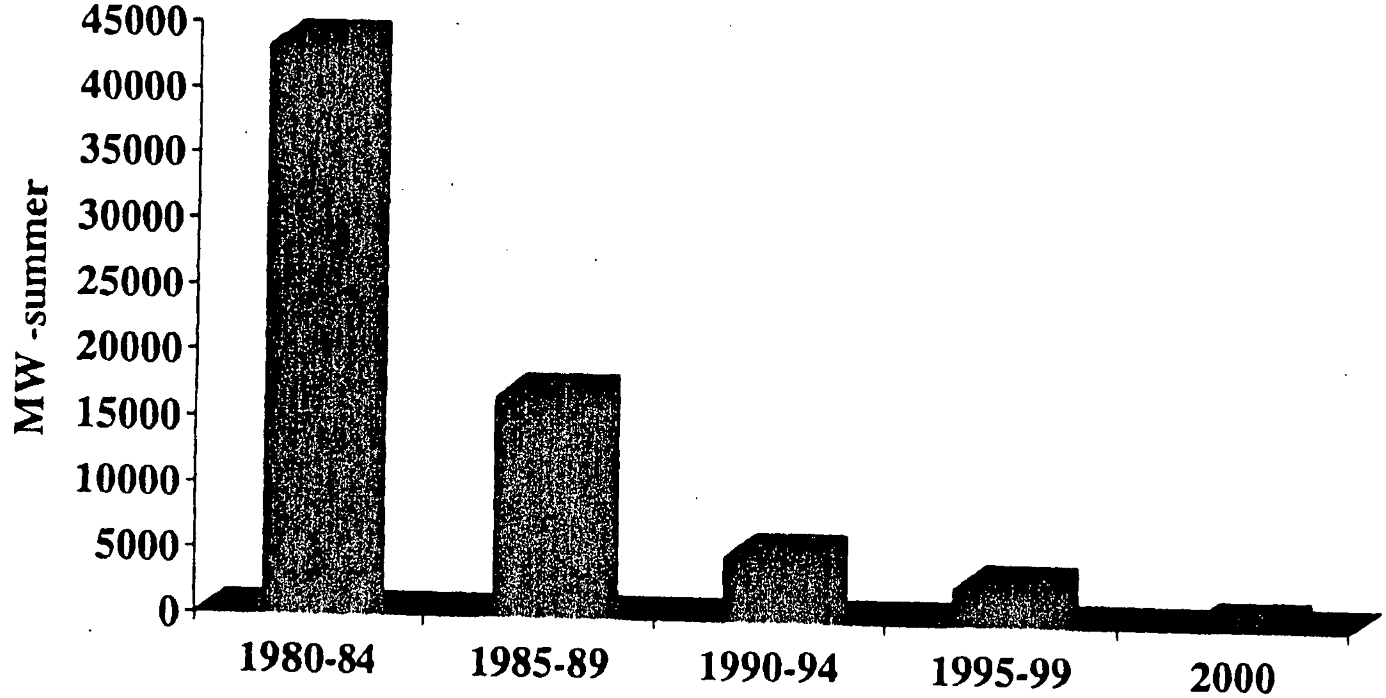
List Price: $150.00

EEI Associate Member Price: $75.00

A PDF file will be e-mailed to you upon receipt of payment.

230

New Coal Additions 1980-2000



Source: Energy Information Administration

DOE002-0921

911

231

GAS TURBINE - MODULAR HELIUM REACTOR (GT-MHR)

COMMERCIALIZATION PROGRAM BRIEFING

March 2001

GENERAL ATOMICS

GAS TURBINE - MODULAR HELIUM REACTOR (GT-MHR)

COMMERCIALIZATION PROGRAM BRIEFING

- PLANT DESCRIPTION
- PROGRAM DESCRIPTION

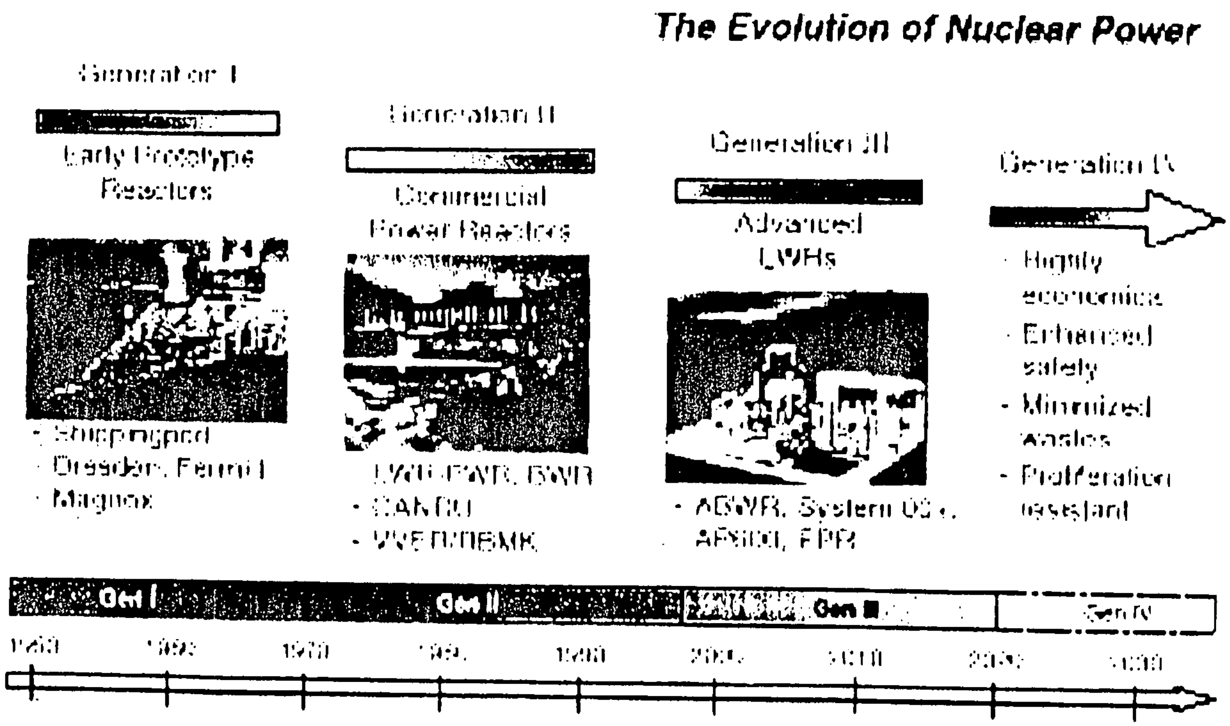
GENERAL ATOMICS

GT-MHR COMMERCIALIZATION PROGRAM

PLANT DESCRIPTION

GENERAL ATOMICS

Nuclear Power Generation IV Initiative

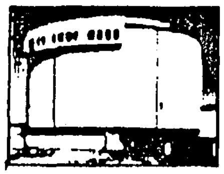


U.S. AND EUROPEAN TECHNOLOGY BASES FOR MODULAR HIGH TEMPERATURE REACTORS

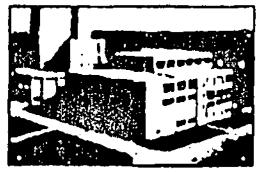
BROAD FOUNDATION OF HELIUM REACTOR TECHNOLOGY

EXPERIMENTAL REACTORS

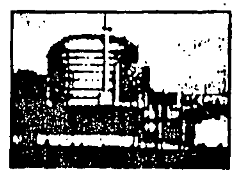
DEMONSTRATION OF BASIC HTGR TECHNOLOGY



DRAGON
(U.K.)
1963 - 76

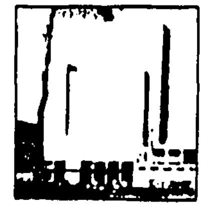


AVR
(FRG)
1967 - 1988



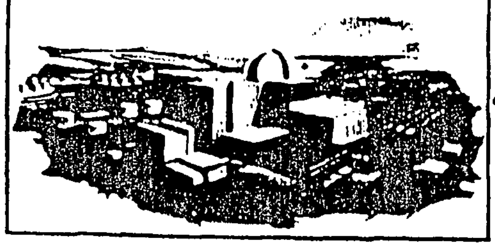
PEACH BOTTOM 1
(U.S.A.)
1967 - 1974

FORT ST. VRAIN
(U.S.A.)
1976 - 1989



THTR
(FRG)
1986 - 1989

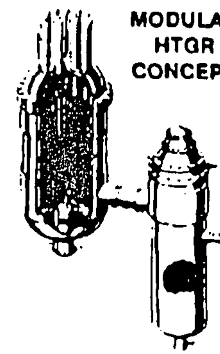
LARGE HTGR PLANTS



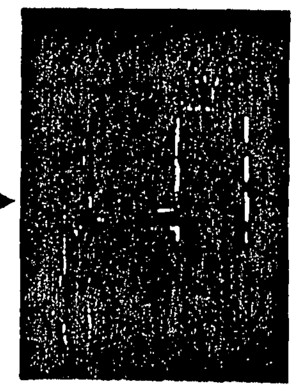
HTGR TECHNOLOGY PROGRAM

- MATERIALS
- COMPONENTS
- FUEL
- CORE
- PLANT TECHNOLOGY

MODULAR HTGR CONCEPT



GT-MHR

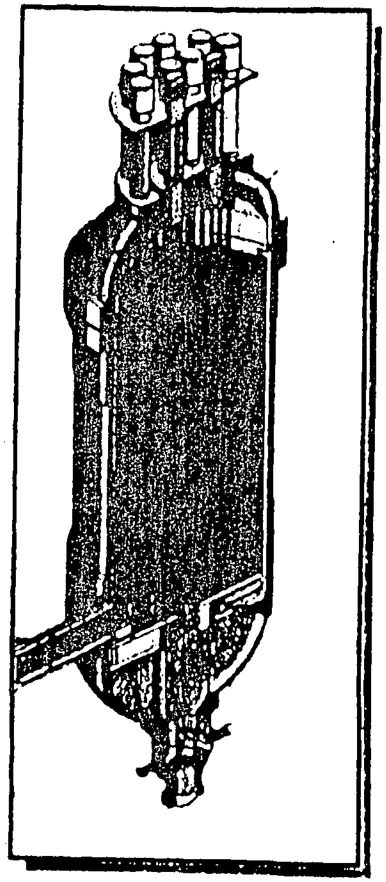


GENERAL ATOMICS

DOE002-0926

916

MODULAR HELIUM REACTOR CHARACTERISTICS ATTRACTIVE FOR GEN IV GOALS



- Helium gas coolant (inert)
- Refractory fuel
  (high temperature capability)
- Graphite reactor core
  (high temperature stability)
- Low power density (order of magnitude lower than LWRs)
- Demonstrated technologies

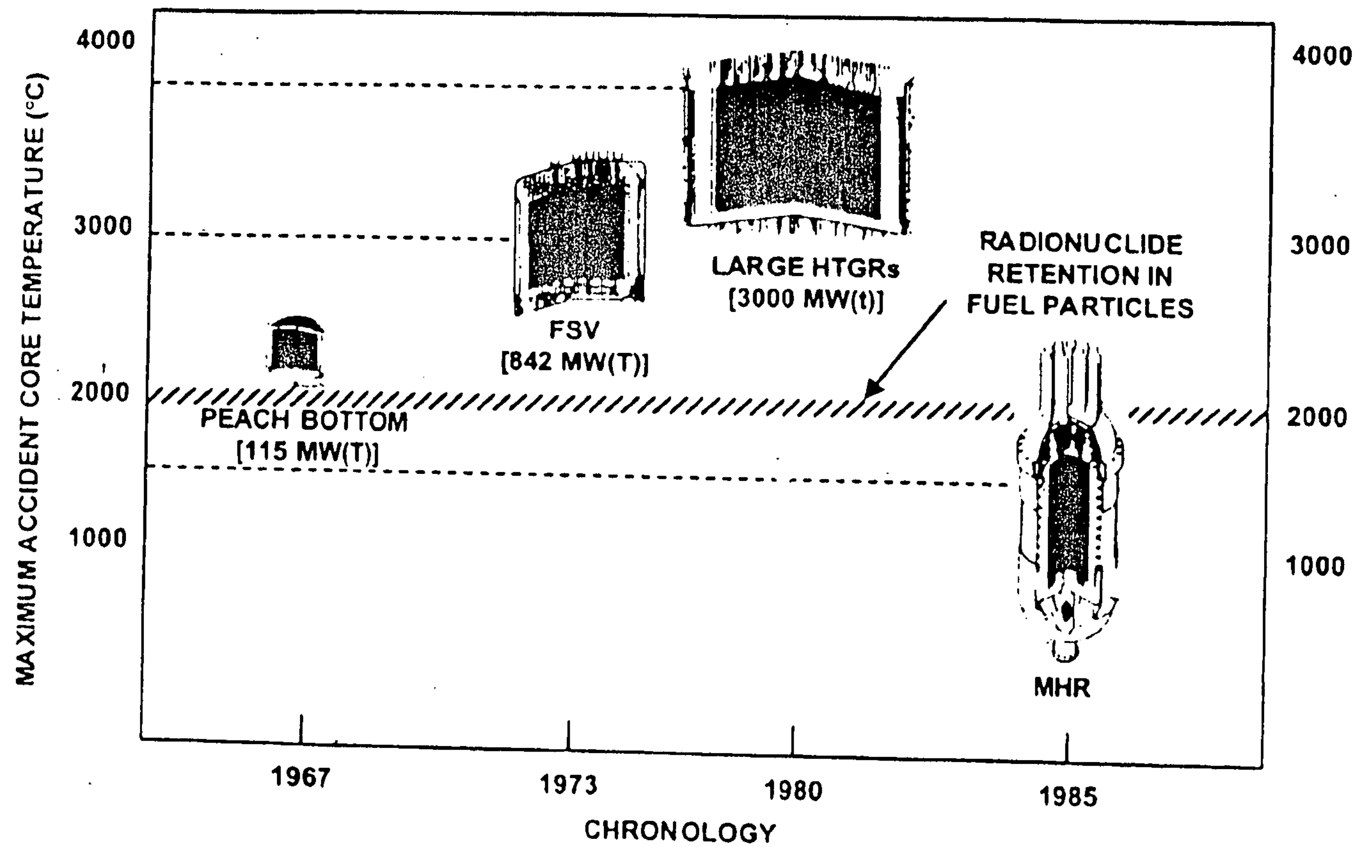
...EFFICIENT, RELIABLE PERFORMANCE
WITH INHERENT SAFETY

GENERAL ATOMICS

DOE002-0927

L-271(3)
6-6-95

MODULAR HELIUM REACTOR REPRESENTS A FUNDAMENTAL CHANGE IN REACTOR DESIGN AND SAFETY PHILOSOPHY



...SIZED AND CONFIGURED TO TOLERATE EVEN A SEVERE ACCIDENT

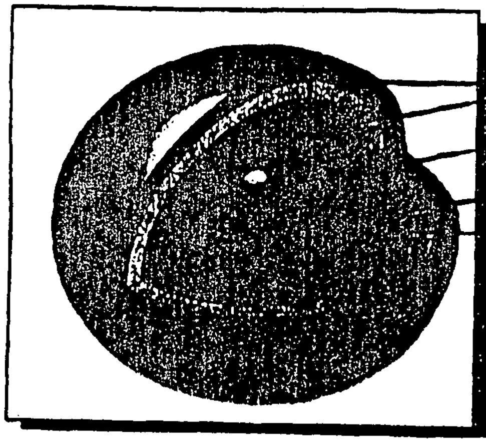
GENERAL ATOMICS

I-222(1)
1-12-96

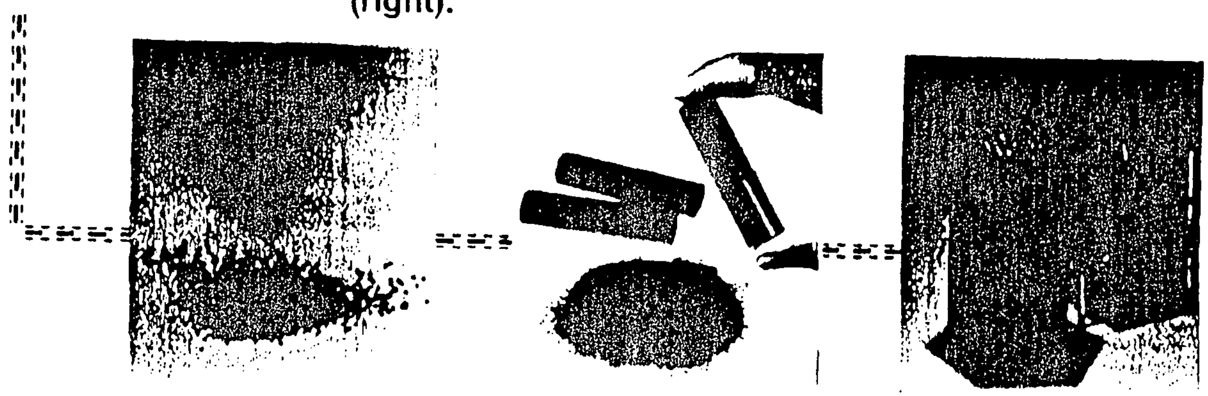
DOE002-0928

918

CERAMIC FUEL RETAINS ITS INTEGRITY UNDER SEVERE ACCIDENT CONDITIONS



TRISO Coated fuel particles (left) are formed into fuel rods (center) and inserted into graphite fuel elements (right).



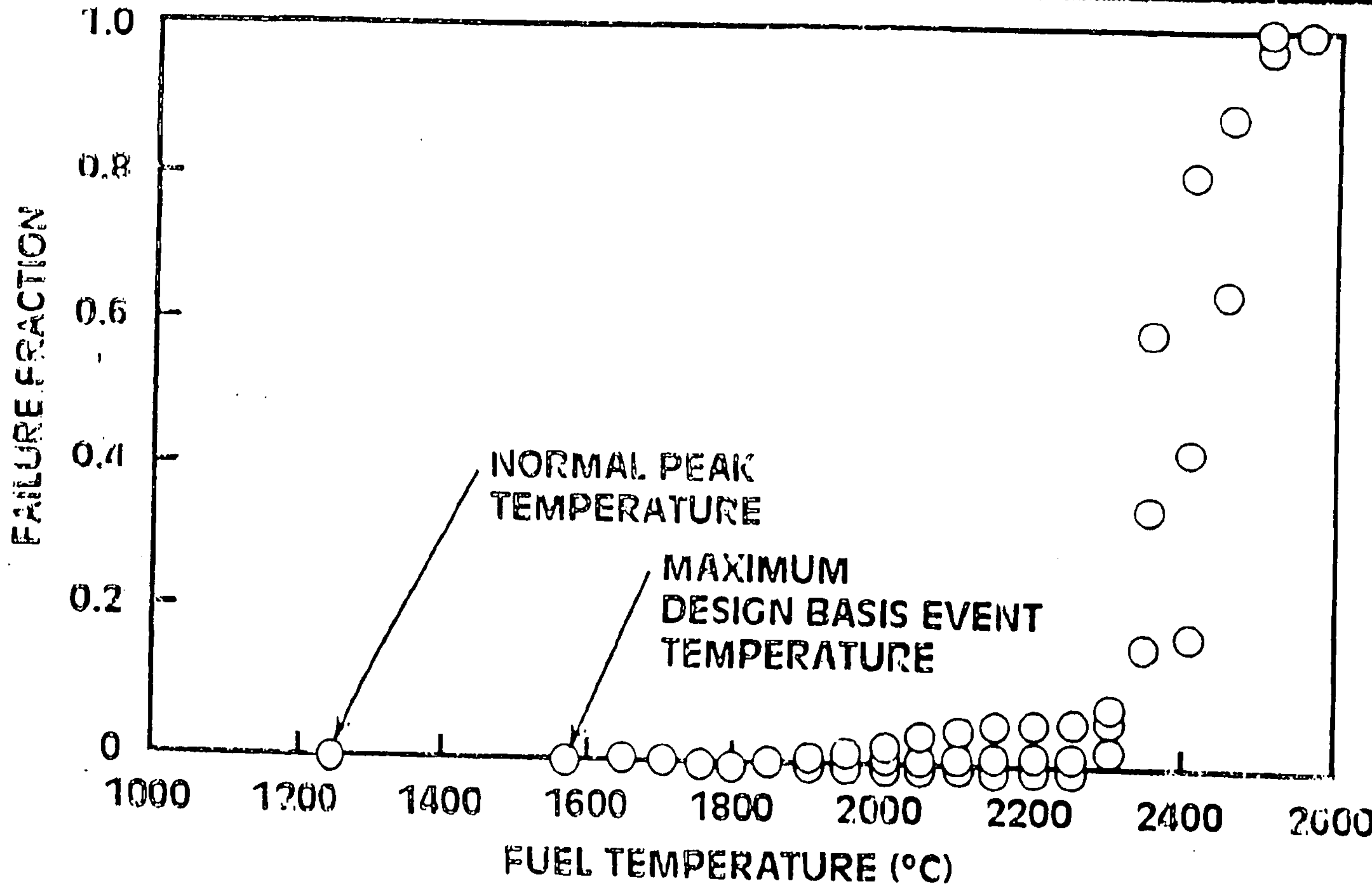
PARTICLES **COMPACTS** **FUEL ELEMENTS**

GENERAL ATOMICS

919

L-029(5)
4-14-94

[illegible] STABLE TO BEYOND MAXIMUM ACCIDENT TEMPERATURES



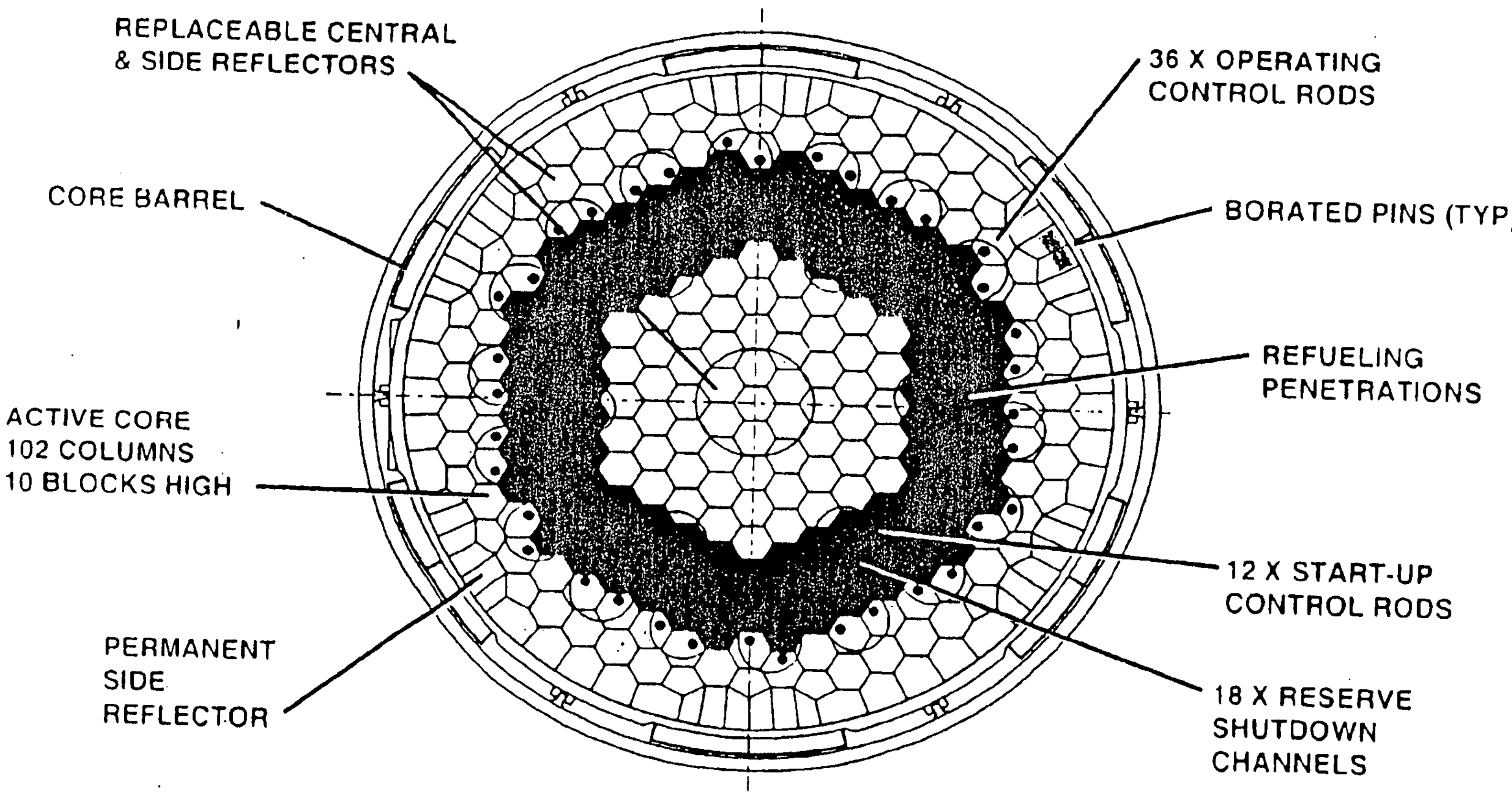
GENERAL ATOMICS

L-266(1)
7-28-94
W-9

920

DOE002-0930

ANNULAR REACTOR CORE LIMITS FUEL TEMPERATURE DURING ACCIDENTS



...ANNULAR CORE USES EXISTING TECHNOLOGY

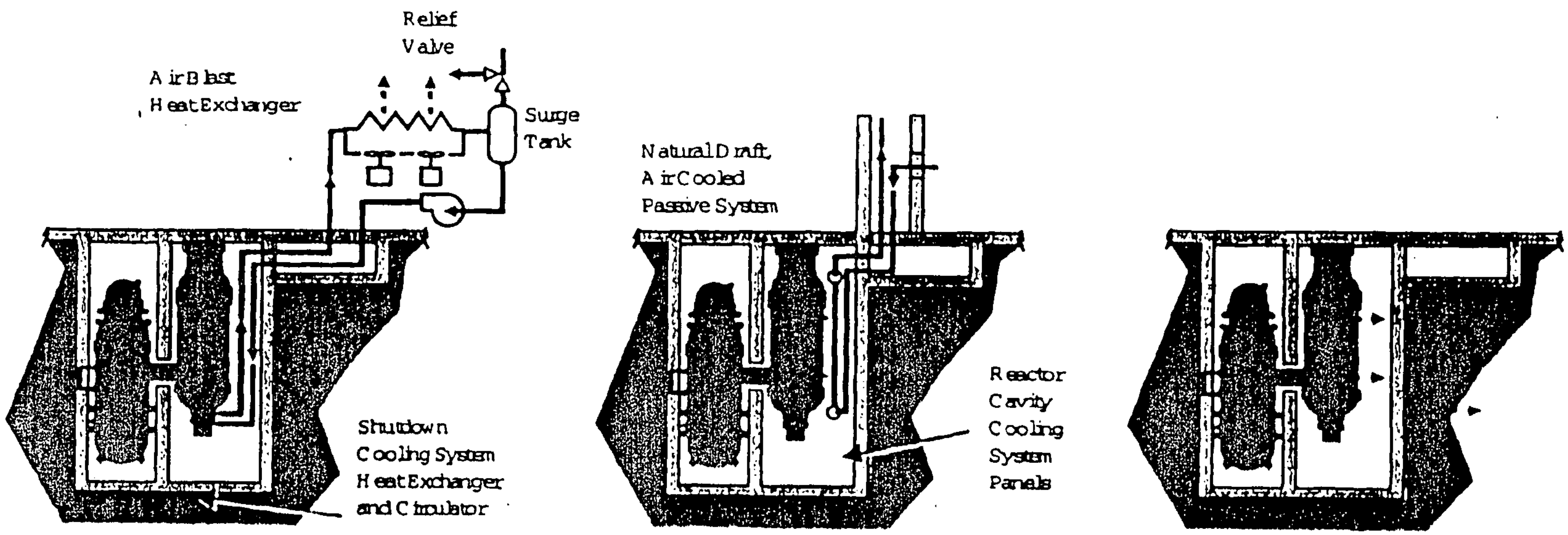
GENERAL ATOMICS

L-199(10)
6-9-95

DOE002-0931

921

POSSIBLE DECAY HEAT REMOVAL PATHS WHEN NORMAL POWER CONVERSION SYSTEM IS UNAVAILABLE



A) Active Shutdown Cooling System

B) Passive Reactor Cavity Cooling System

C) Passive Radiation and Conduction of Afterheat to Silo Containment (Beyond Design Basis Event)

. . . DEFENSE-IN-DEPTH BUTTRESSED BY INHERENT CHARACTERISTICS

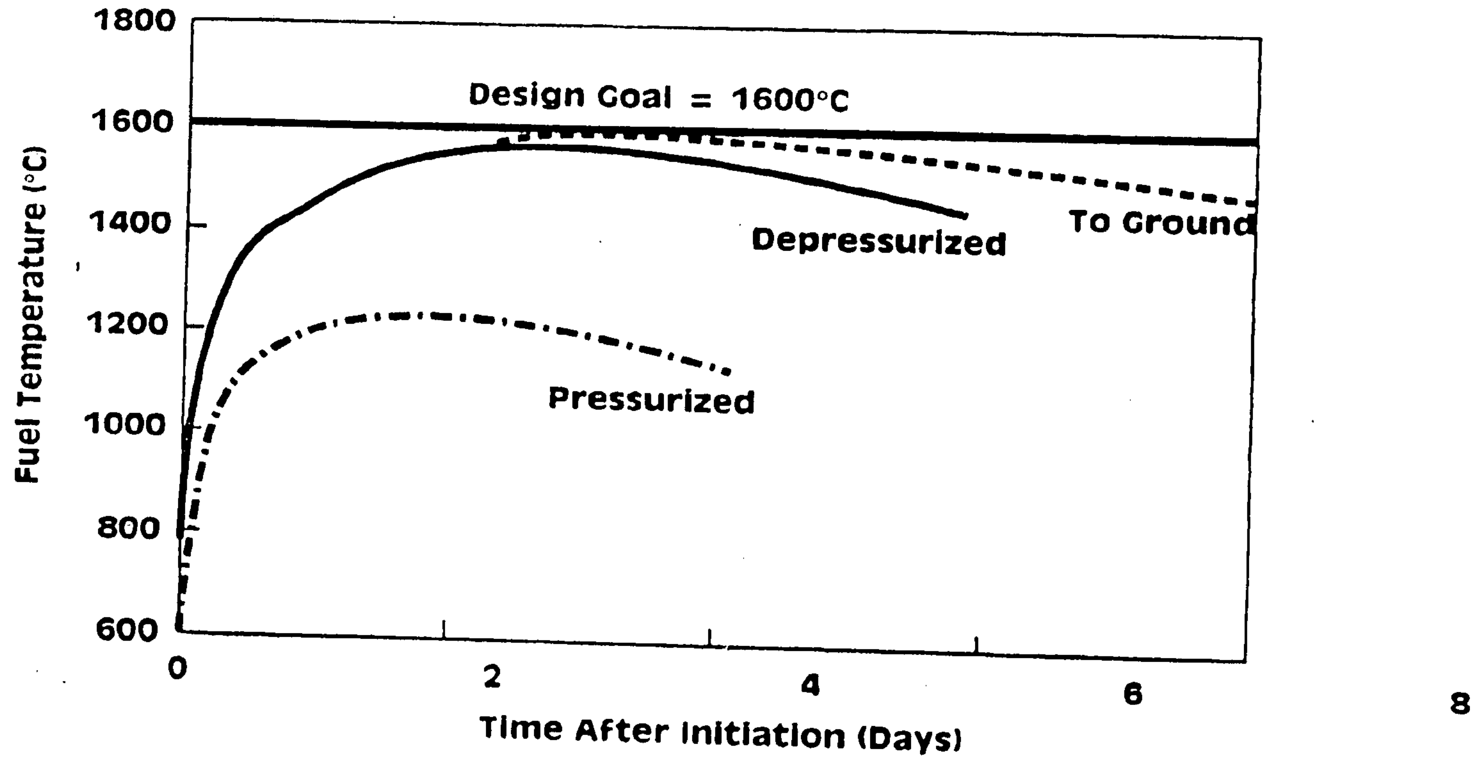
GENERAL ATOMICS

L-266(2)
7-28-94

DOE002-0932

922

FUEL TEMPERATURES REMAIN BELOW DESIGN LIMITS DURING LOSS OF COOLING EVENTS



... PASSIVE DESIGN FEATURES ENSURE FUEL REMAINS BELOW 1600°C

GENERAL ATOMICS

L-340(3)
11-16-94

DOE002-0933

923

PASSIVE SAFETY BY DESIGN

- Fission Products Retained in Coated Particles
  - *High temperature stability materials*
  - *Refractory coated fuel*
  - *Graphite moderator*

- Worst case fuel temperature limited by design features
  - *Low power density*
  - *Low thermal rating per module*
  - *Annular Core*
  - *Passive heat removal*

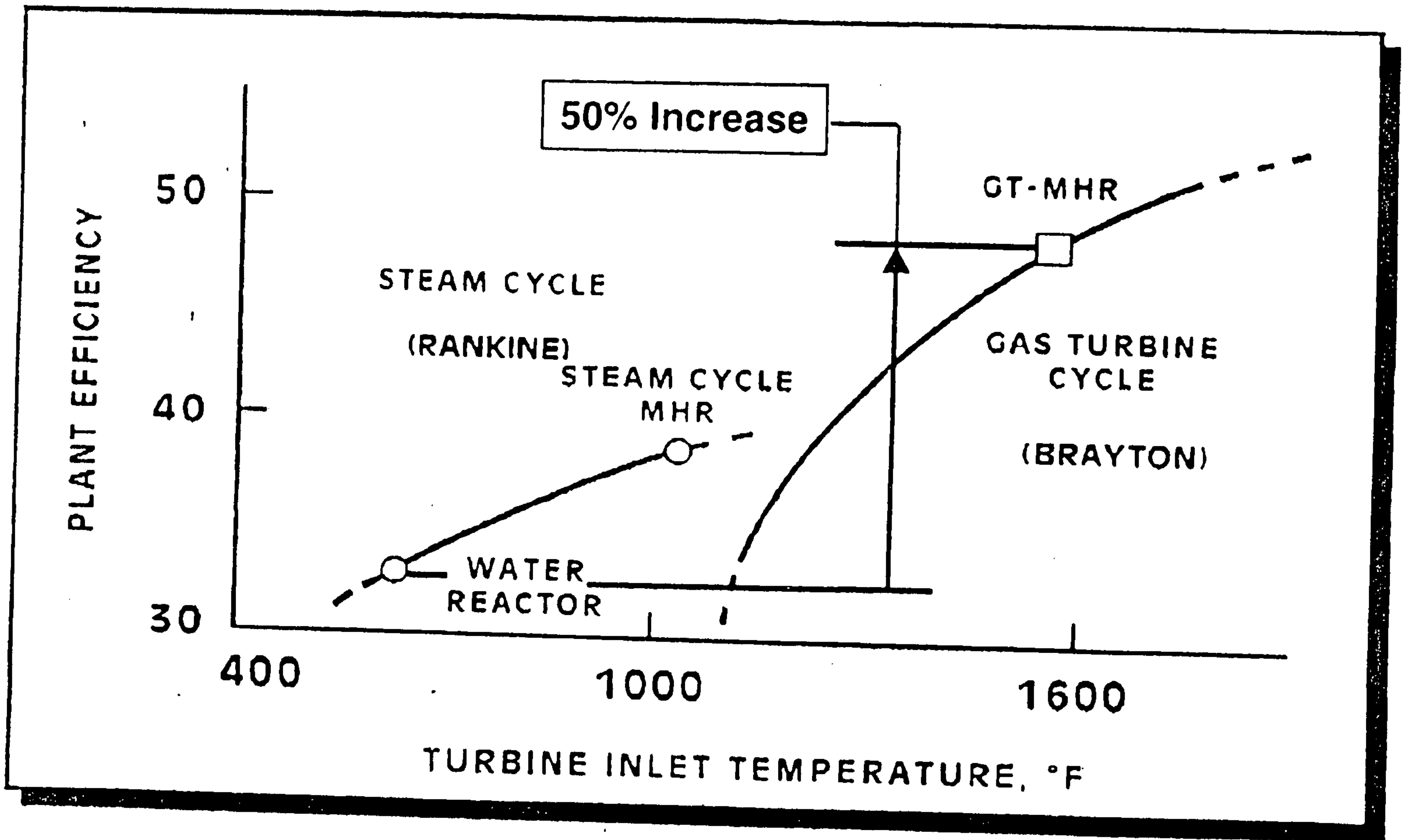
....CORE CAN'T MELT

- Core Shuts Down Without Rod Motion

GENERAL ATOMICS

DOE002-0934

HIGH TEMPERATURE GAS REACTORS HAVE UNIQUE ABILITY TO USE BRAYTON CYCLE



L-029(4)
6-9-94

GENERAL ATOMICS

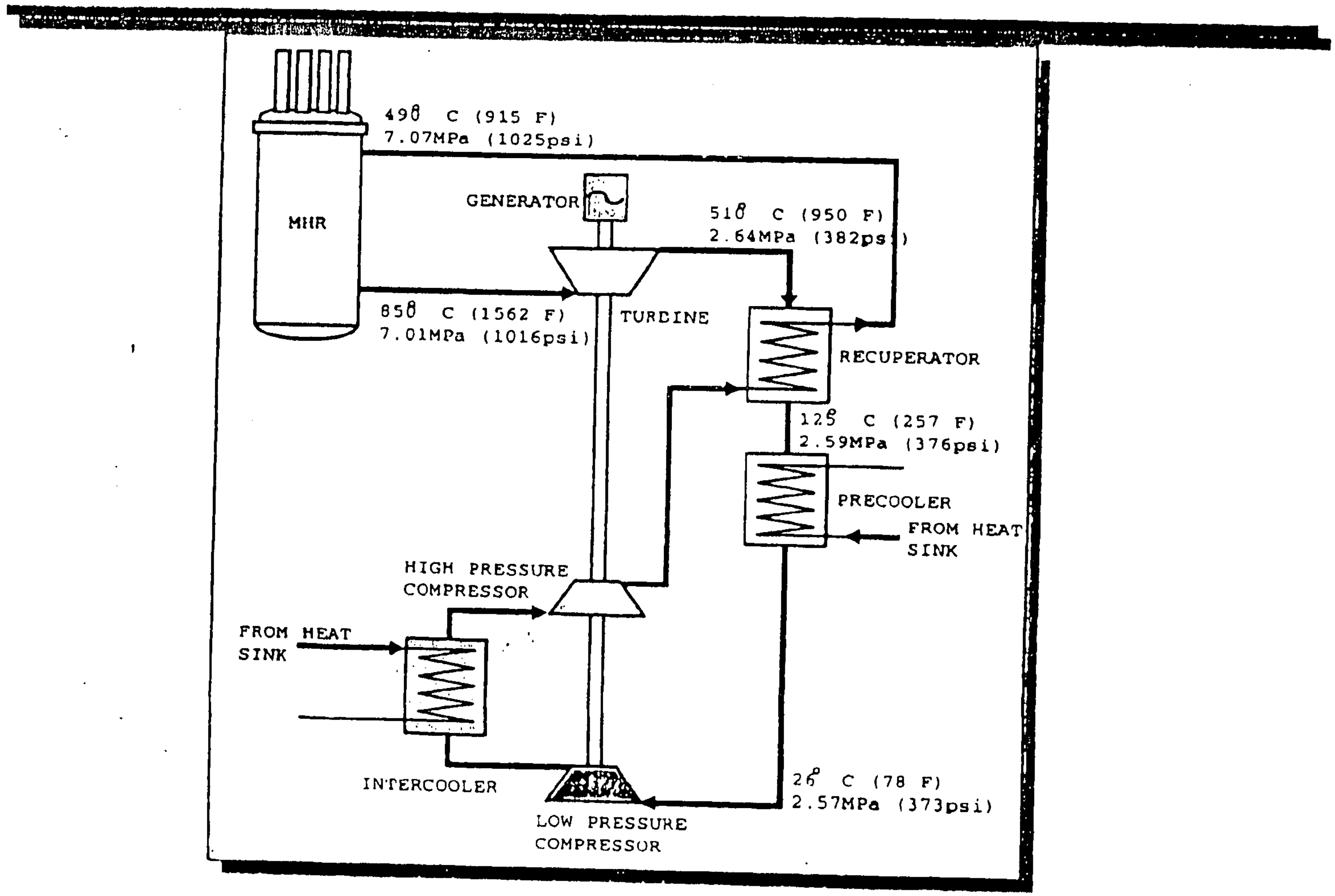
DOE002-0935

TECHNOLOGY ADVANCEMENTS HAVE ENABLED THE GT-MHR

- Small Passively Safe Modular Helium Reactor
  - *turbine size requirements reduced*
  - *insensitive to turbine failure accidents*
- Large Gas Turbine Engines
  - *significant increase in industrial applications*
  - *size now match modular reactor size*
- Magnetic Bearings
  - *eliminates oil ingress concerns*
  - *improves performance and reliability*
  - *rapidly increasing industrial experience; larger sizes*
- Compact Heat Exchangers
  - *dramatically improves efficiency*
  - *size improves design integration*
  - *extensive fossil operating experience*

GENERAL ATOMICS

GT-MHR FLOW SCHEMATIC



DOE002-0937

927

L-271(12a)
8-14-94
A-36

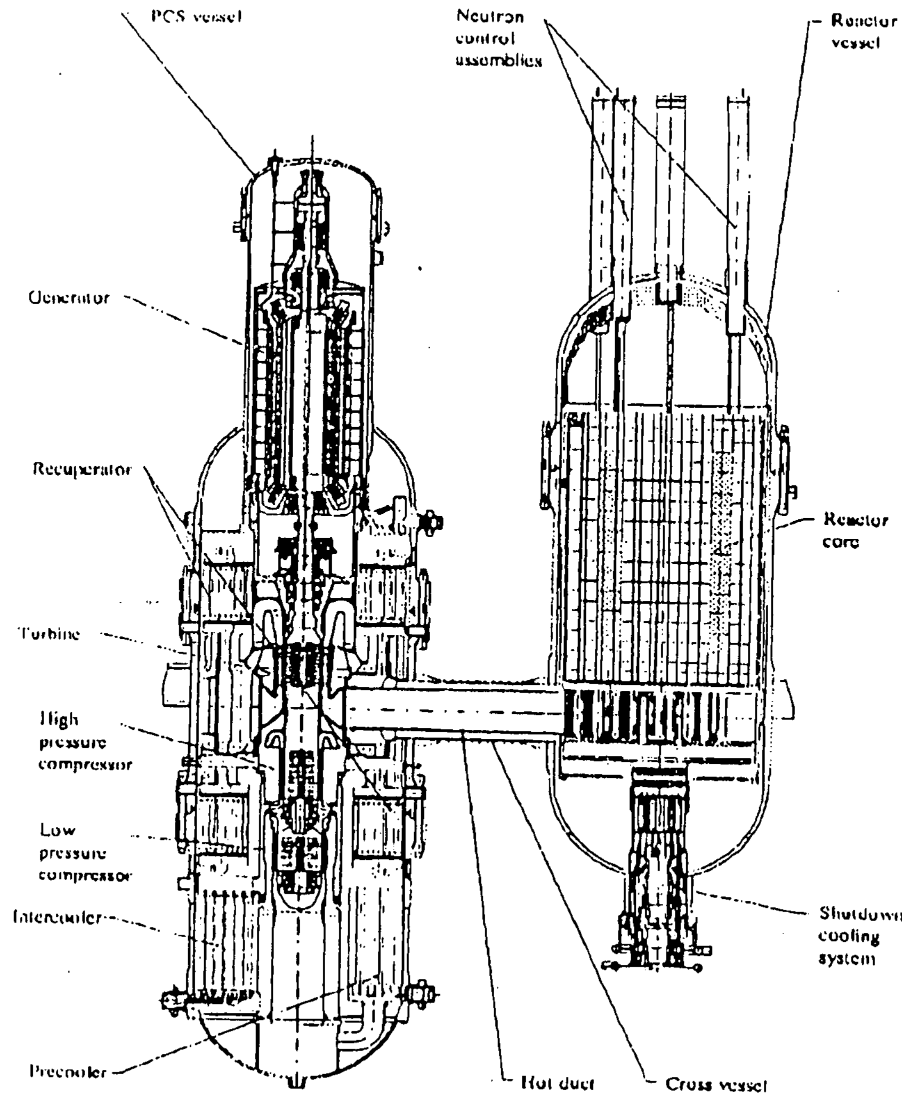
GENERAL ATOMICS

[redacted]

GT-MHR COMBINES MELTDOWN-PROOF ADVANCED REACTOR AND GAS TURBINE

POWER LEVEL 600 MWt

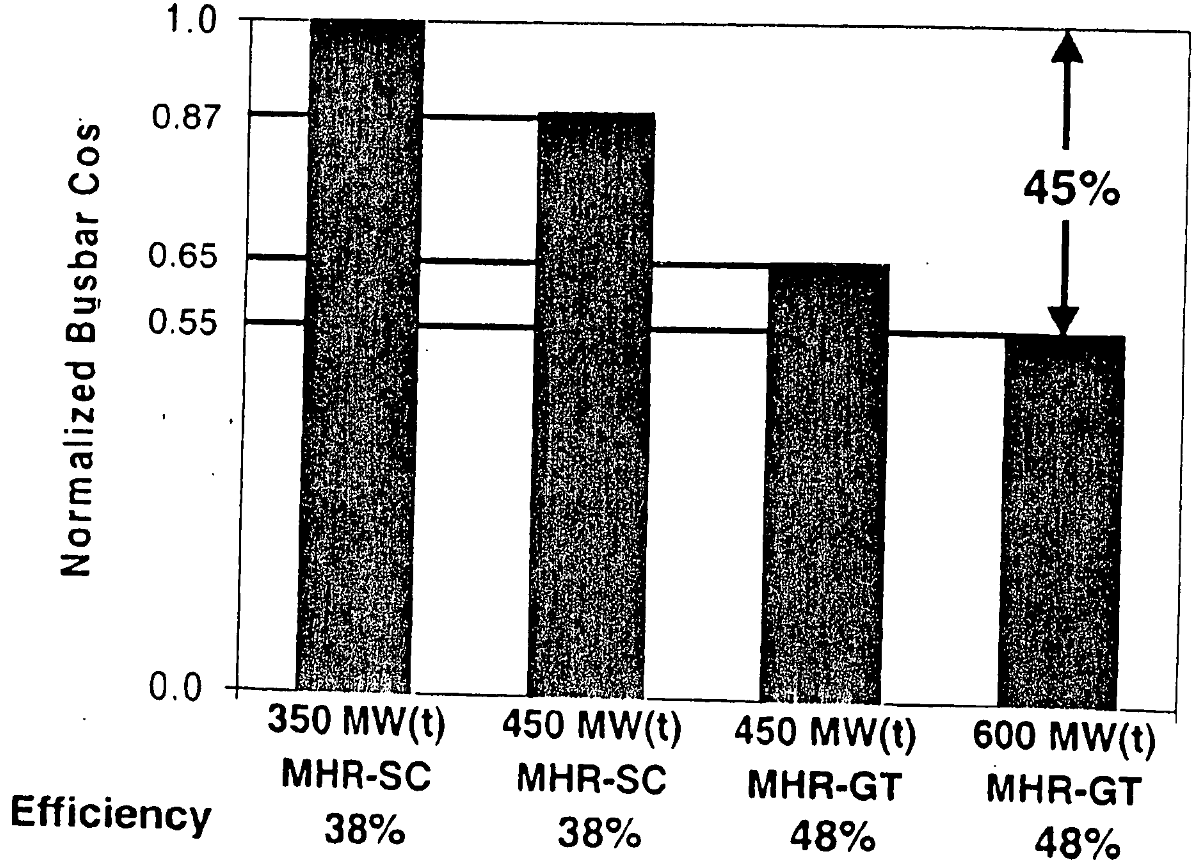
GENERAL ATOMICS



DOE002-0938

928

600 MW(t) GT-MHR REDUCES POWER COST BY 45% COMPARED TO 350 MW(t) STEAM CYCLE

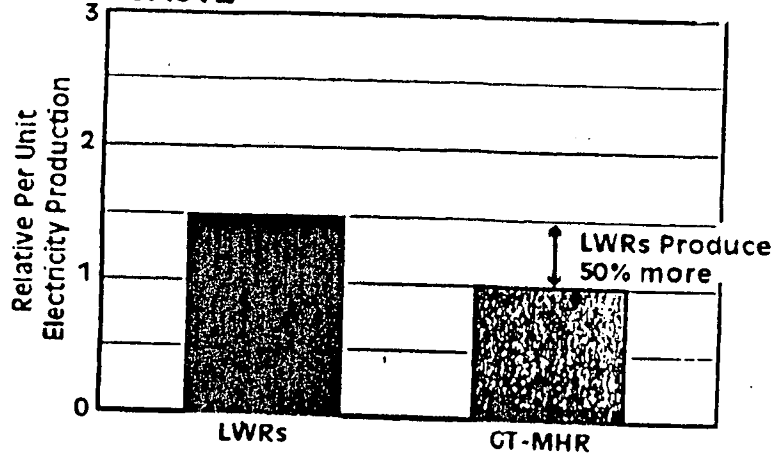


GENERAL ATOMICS

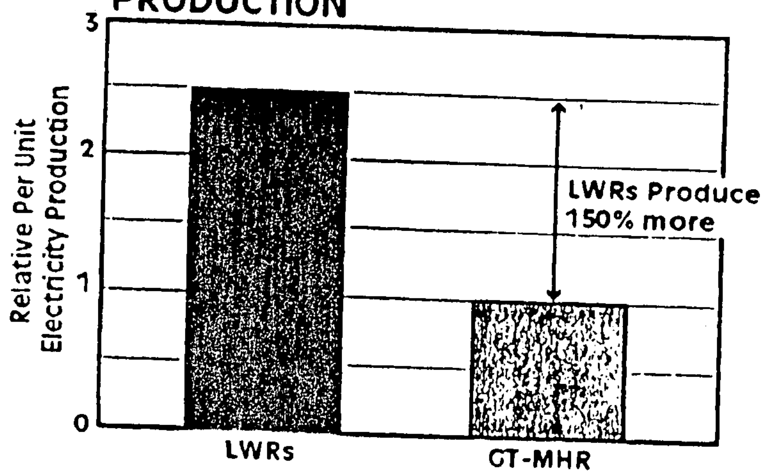
DOE002-0939

GT-MHR OFFERS MAJOR ENVIRONMENTAL BENEFITS

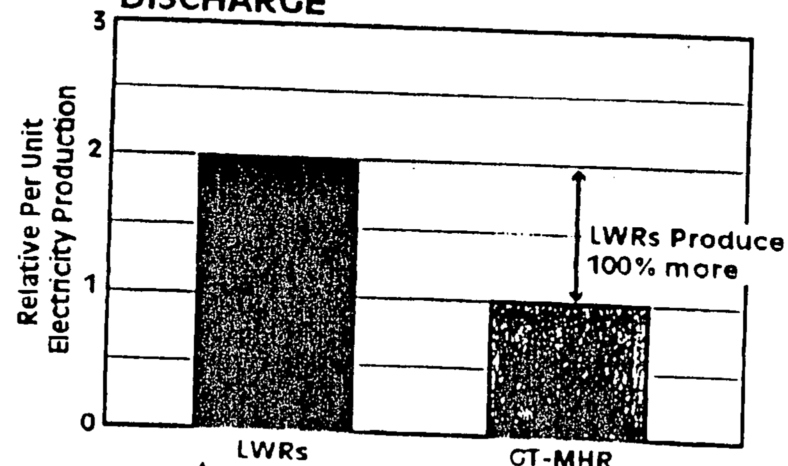
HIGH LEVEL WASTE



ACTINIDE PRODUCTION



THERMAL DISCHARGE



GENERAL ATOMICS

L-592(2)
11-14-95

IN SUMMARY, GT-MHR IS A GENERATION IV SYSTEM

- Inherent safety Features- No core melt
- High thermal efficiency resulting Lower Cost
- Significantly reduced environmental impact
- Superior radio-nuclide retention for long-term spent disposal

GENERAL ATOMICS

GT-MHR COMMERCIALIZATION PROGRAM

PROGRAM DESCRIPTION

GENERAL ATOMICS

GT-MHR NOW BEING DEVELOPED IN INTERNATIONAL PROGRAM

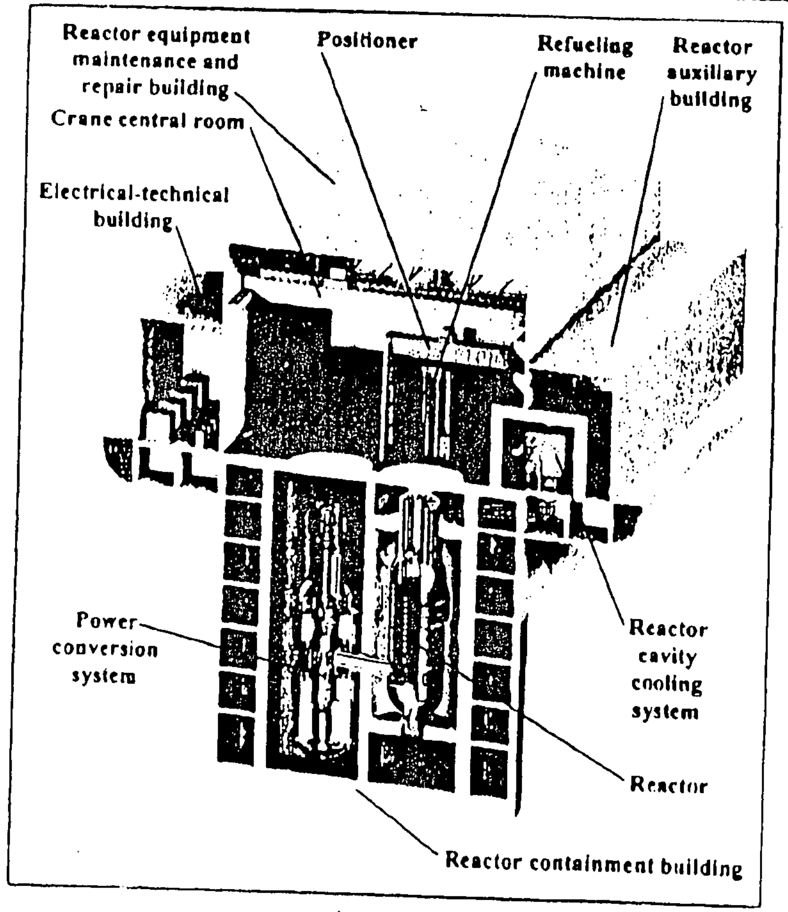
- In Russia under joint US/RF agreement for management of surplus weapons Pu
- Sponsored jointly by US (DOE) and RF (Minatom); supported by Japan and EU
- Conceptual design completed; preliminary design complete early 2002

GENERAL ATOMICS

INTERNATIONAL GT-MHR PROGRAM

- Design, construct and operate a prototype GT-MHR module by 2009 at Tomsk, Russia
- Design, construct, and license a GT-MHR Pu fuel fabrication facility in Russia
- Operate first 4-module GT-MHR by 2015 with a 250 kg plutonium/ year/module disposition rate

....Fuel contains Pu only
......No fertile component

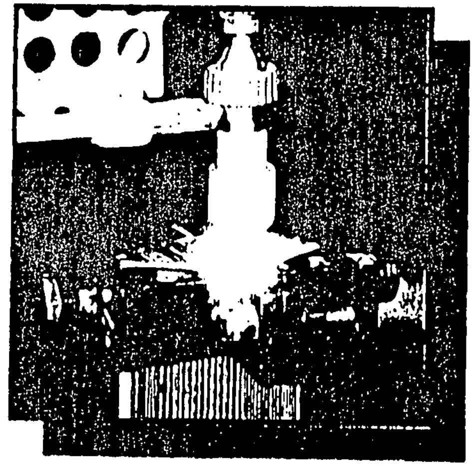


GENERAL ATOMICS

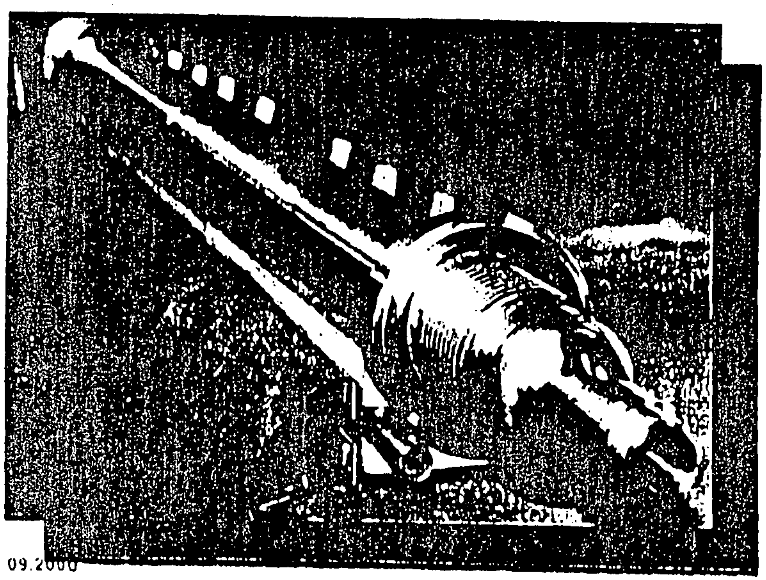
DOE002-0944

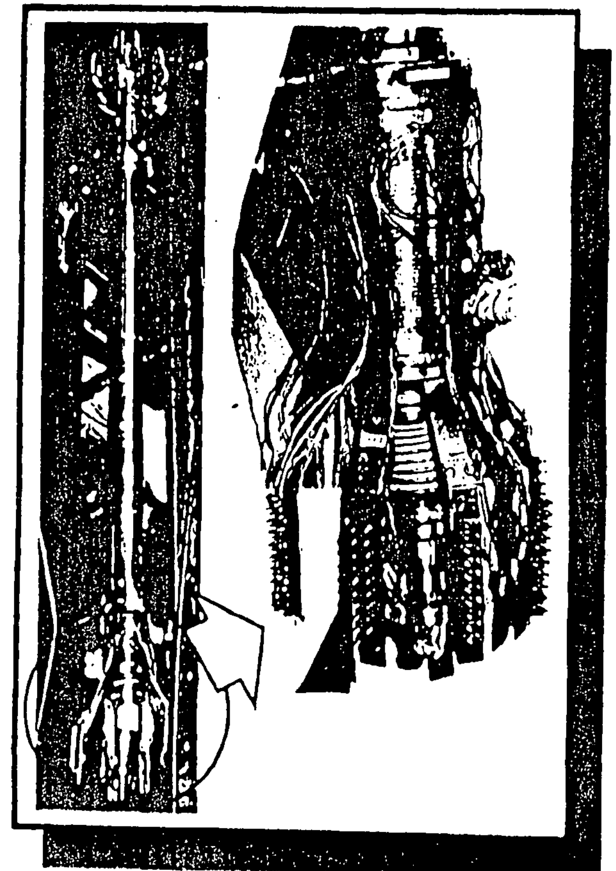
Russian Technological Developments. Recuperator

Heat Exchange Element Fabrication



Recuperator Heat Exchange Element





Tests of full scale heat exchange element in helium test facility

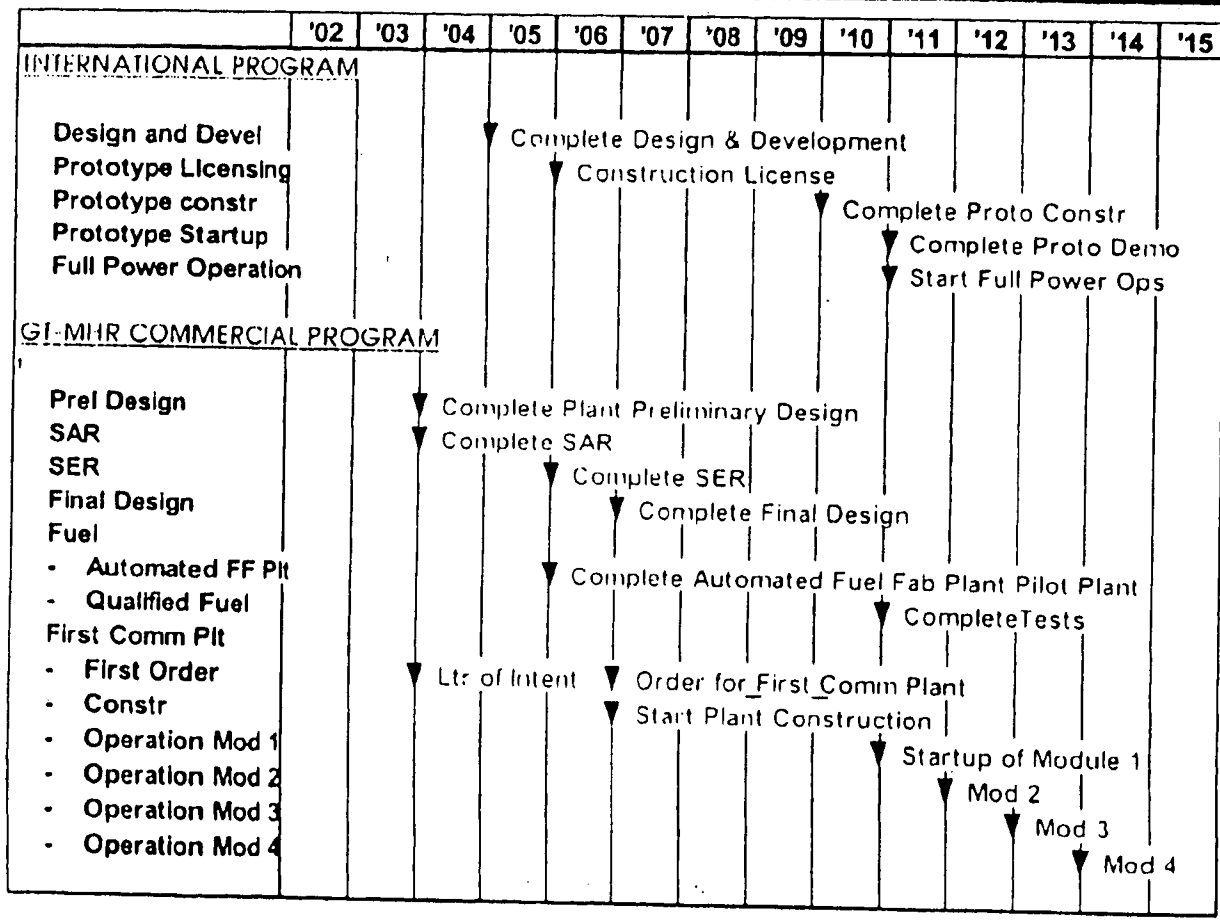
COMMERCIALIZATION PROGRAM

COMMERCIAL PROGRAM = INTERNATIONAL PROGRAM TECHNOLOGY + URANIUM FUEL RATHER THAN Pu FUEL

Plant construction can start in 5 years

GENERAL ATOMICS

COMMERCIAL PROGRAM FOLLOWS INTERNATIONAL PROGRAM

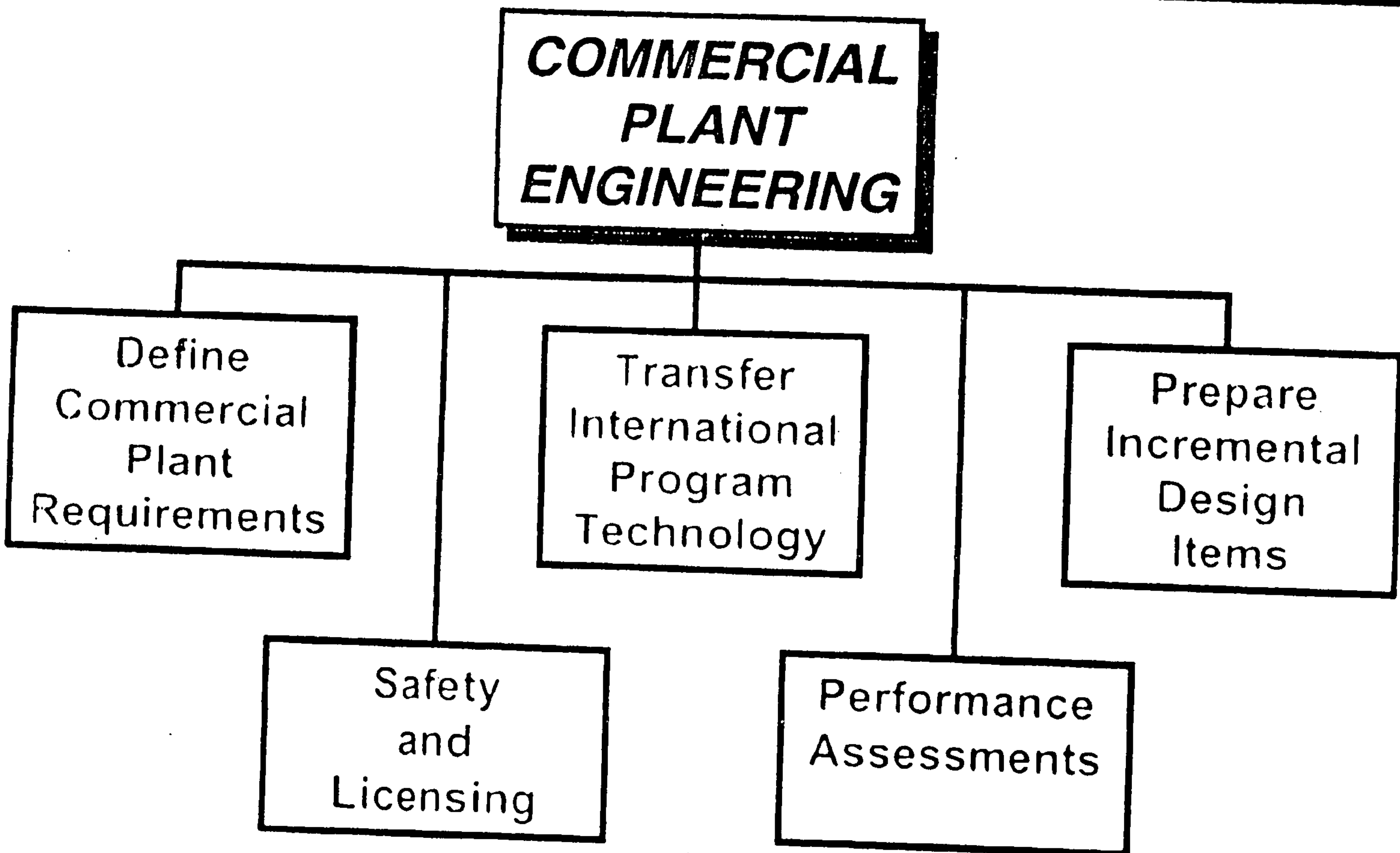


GENERAL ATOMICS

DOE002-0947

937

LIMITED ENGINEERING WORK REQUIRED



GENERAL ATOMICS

DOE002-0948

PLANT REQUIREMENTS PLANNED FROM SEVERAL SOURCES

Externally Imposed Requirements

- US regulatory requirements
- US codes and standards

Utility/User Requirements
(safety, economics, etc)

Technology from International Program

COMMERCIAL PLANT REQUREMENTS

GENERAL ATOMICS

DOE002-0949

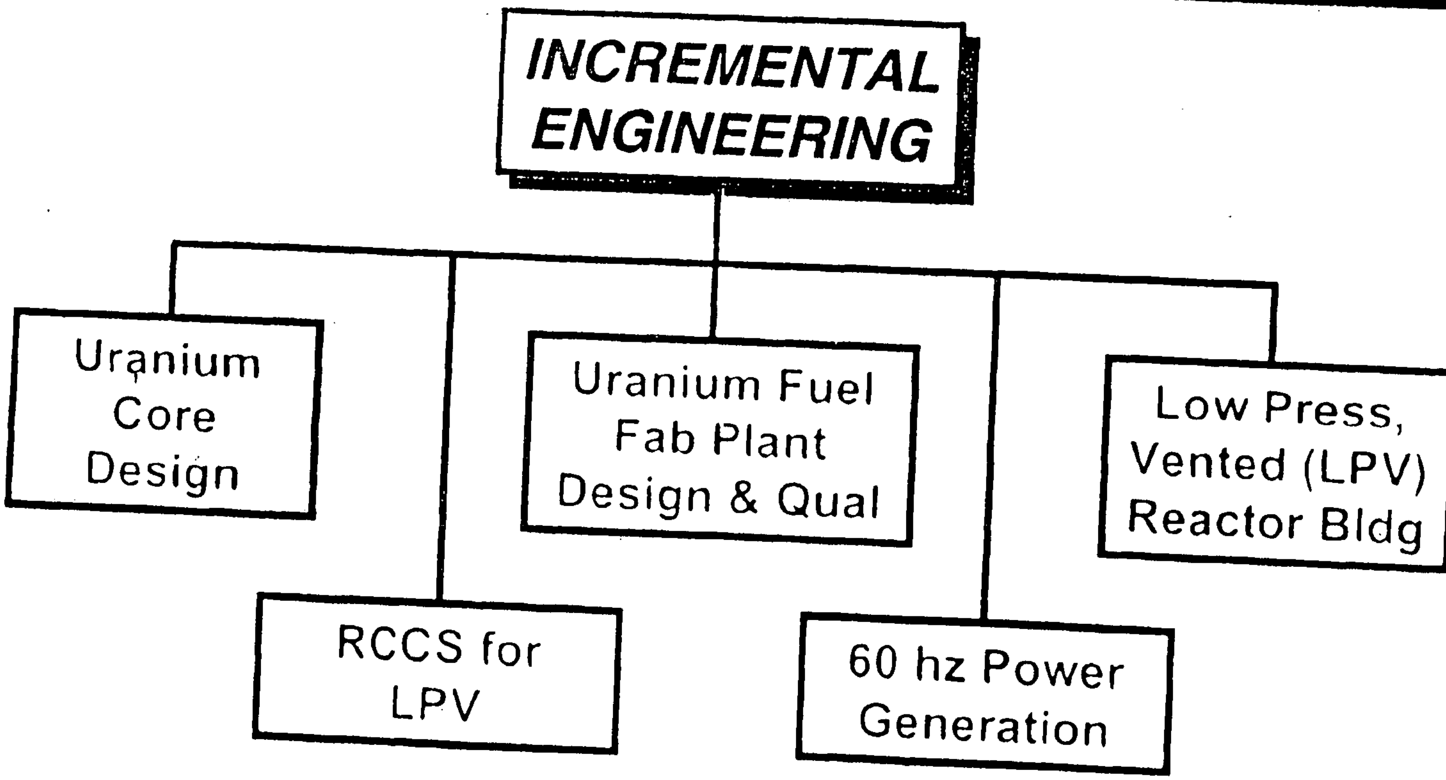
TECHNOLOGY TRANSFER ACTIVITIES

INTERNATIONAL PROGRAM TECHNOLOGY

- Preparation of SDDs to US standards
  - info from equivalent docs prepared to Russian stds
- Adaptation of design & tech dev reports
  - verify compliance to US requirements
- Adaptation of dwgs & specs
  - convert to US codes and stds

GENERAL ATOMICS

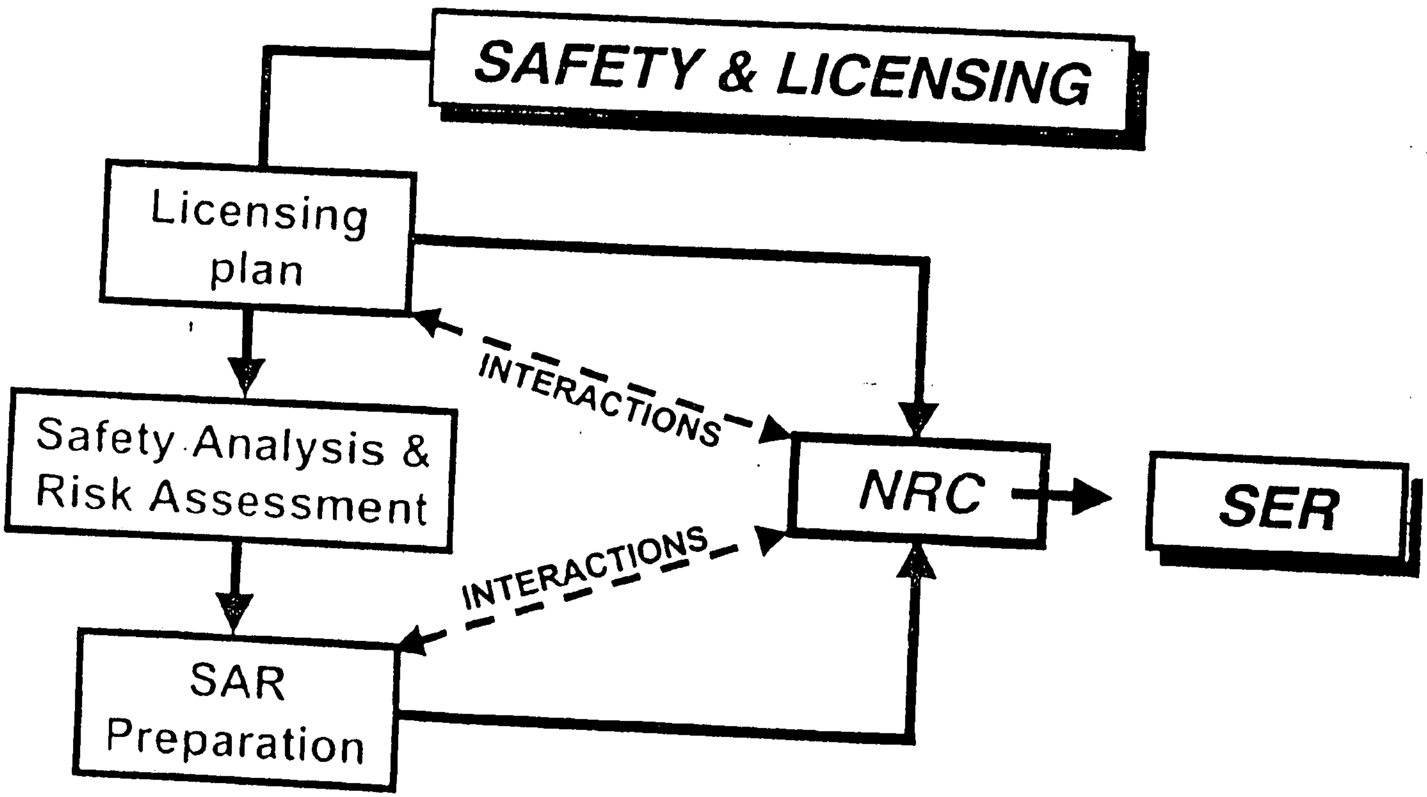
INCREMENTAL ENGINEERING WORK ACTIVITIES



..........*No New R&D*

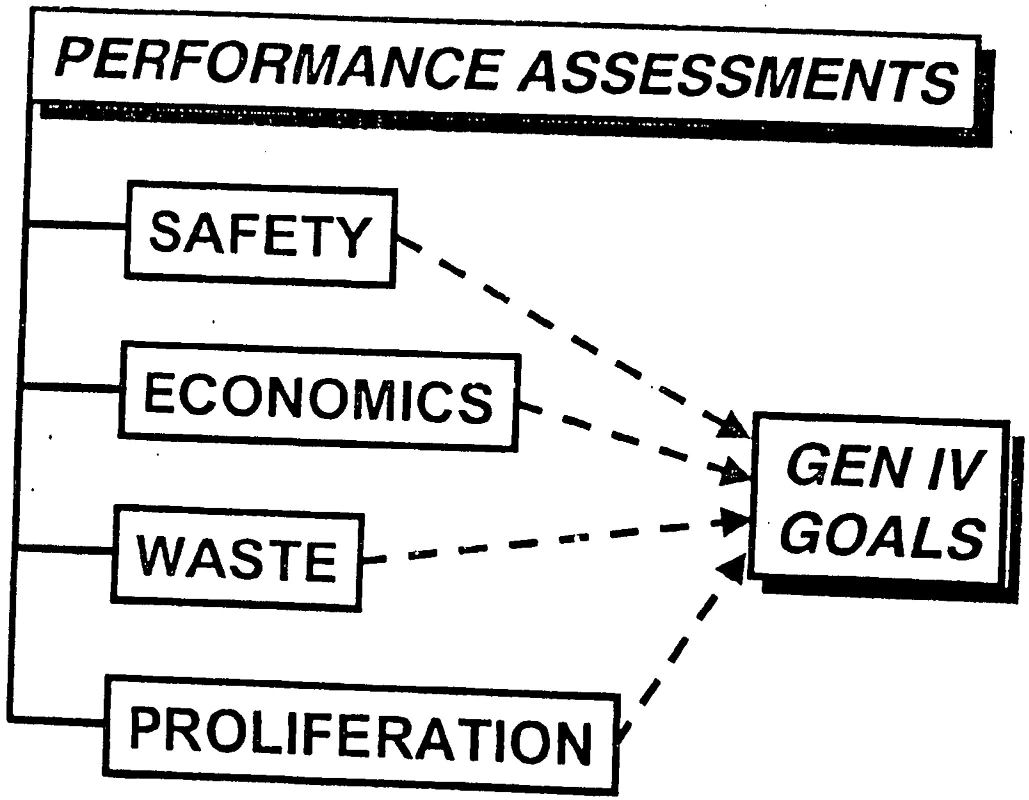
GENERAL ATOMICS

SAFETY & LICENSING ACTIVITIES



GENERAL ATOMICS

PERFORMANCE ASSESSMENT ACTIVITIES PLANNED



GENERAL ATOMICS

DOE002-0953

943

COMMERCIAL PROGRAM SUMMARY

- GEN IV PLANT
- COST EFFECTIVE
- NEAR TERM

GENERAL ATOMICS

232

FOOTHILLS PIPE LINES LTD.

Northern Backgrounder

AUGUST 2000

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY ---- 1

II. BACKGROUND ---- 6

III. THE DECISIONAL PROCESS IN CANADA AND THE UNITED STATES ---- 8

A. The Recommendation of the FPC 9
B. The Reasons For Decision Of The Canadian NEB 9
C. The Transit Pipeline Treaty 10
D. The Agreement Between Canada And The U.S. 10
E. The U.S. President's Decision and Report to Congress 11
F. U.S. Congressional Approval Of The ANGTS 12
G. Certification Of The ANGTS By The FERC 12
H. The Canadian Northern Pipeline Act 13
I. The 1981 Waiver of Law 13

IV. THE ANGTS PREBUILD PROJECT ---- 14

A. The Prebuild Contracts 14
B. Canadian And U.S. Prebuild Regulatory Approvals 16
C. Construction Of The Prebuild 22
D. Subsequent Prebuild Developments 23

V. PRESIDENTIAL FINDING ON ALASKAN GAS EXPORTS ---- 27

VI. COMPLETION OF THE ANGTS ---- 27

VII. THE BAYER REPORT ---- 30

VIII. 1999 NORTHERN BORDER RATE CASE ---- 31

X. THE MACKENZIE VALLEY PIPELINE PROJECT ---- 33

XI. OTHER DEVELOPMENTS ALASKA NORTH SLOPE PROJECT ---- 34

I. EXECUTIVE SUMMARY

- In 1977, Canada and the United States signed an Agreement for the construction and operation of the Alaska Natural Gas Transportation System ("ANGTS"), a 5,000-mile pipeline project which would traverse Canada and provide the U.S. with access to its Alaskan gas reserves.

- In the Agreement the two governments designated Foothills Pipe Lines Ltd. ("Foothills") as the company responsible for the construction and operation of the Canadian segment of the system and the U.S. sponsors.

- In September 1977, President Carter issued his Decision and Report to Congress on the Alaska Natural Gas Transportation System. In that decision, the ANGTS was found to be the most economic and environmentally sound means of transporting Alaskan gas to markets in the lower forty-eight states.

- The President's Decision and the Agreement were ratified by the U.S. Congress in late 1977, whereupon the U.S. Federal Energy Regulatory Commission ("FERC") issued certificates of public convenience and necessity to the U.S. sponsors for the construction and operation of the U.S. segments of the project subject to meeting certain conditions related to construction costs and schedule, finance and environment.

- In April 1978, the Canadian Parliament enacted the Northern Pipeline Act which granted certificates of public convenience and necessity to the Foothills subsidiaries responsible for the construction and operation of the 2,000-mile Canadian segment of the ANGTS. The Act also established the Northern Pipeline Agency and gave it authority to oversee the construction of the system in Canada.

- One of the main reasons for the United States' selection of the trans-Canadian ANGTS was the President's belief that it would "provide the opportunity to obtain additional gas at an earlier date by early construction of portions of the southern Canadian and lower 48 sections ... with delivery of gas from Alberta ... in advance of delivery of Alaskan gas."

- To make prebuilding a reality, Pan-Alberta Gas Ltd. ("Pan-Alberta"), a Canadian marketing company, signed two contracts in 1978 under which it agreed to supply Northwest Alaskan Pipeline Company ("Northwest Alaskan") approximately 800 MMcfd for delivery through the Eastern Leg of the ANGTS and approximately 240 MMcfd for delivery through the Western Leg. In addition, Pan-Alberta signed several gas sales and transportation contracts, including a transportation agreement with Foothills for delivery of gas to the Eastern and Western Leg delivery points on the international border.

- In 1980, the Federal Energy Regulatory Commission ("FERC"), as a successor to the Federal Power Commission ("FPC"), issued a series of orders approving the Prebuild phase of the ANGTS.

- On July 1, 1980, Congress passed a Joint Resolution which reaffirmed congressional support for the ANGTS. After finding, among other things, that prebuilding would "enable this Nation to obtain Canadian natural gas to displace two hundred thousand barrels of foreign oil a day," the Joint Resolution declared that "it is the sense of Congress that the [ANGTS] System remains an essential part of securing this Nation's energy future and, as such, enjoys the highest level of Congressional support for its expeditious construction and completion ..."

- On July 18, 1980, President Carter wrote Prime Minister Trudeau a letter expressing the United States' support for prebuilding and for completion of the remainder of the ANGTS.

- Based upon the commitments of the FERC, the President, and the Congress, the NEB issued a decision in July 1980 finding that the financing conditions of the Northern Pipeline Act, as amended, had been satisfied, and that prebuilding the Canadian segment of Phase I of the ANGTS could go forward.

- Subsequent to the Canadian government's approval of the Prebuild Project, and in reliance upon the U.S. commitments described above:

  - Foothills invested approximately one billion dollars in prebuilding 528 miles of the 2000-mile Canadian segment of the ANGTS;

  - Canadian producers invested approximately one billion dollars (Canadian) in the construction of production, plant, and gathering facilities; and

  - NOVA invested approximately $500 million in providing capacity within its intraprovincial pipeline system to transport the Prebuild volumes from numerous Alberta fields to interconnections with the Foothills system.

- Since the initiation of gas deliveries through the ANGTS Prebuild Project, which occurred in 1981 on the Western Leg and in 1982 on the Eastern Leg, the Prebuild contracts have been renegotiated in response to changing conditions in the U.S. gas market while remaining consistent with the integrity of the ANGTS regime. Consistent with the ANGTS regime, the new amendments have been expeditiously approved by regulatory agencies in both Canada and the United States.

- Foothills has invested approximately $500 million in expansions to the Prebuild during the 1990's under the ANGTS regime. Of particular note, in 1993, Foothills expanded its Western Leg facilities in South B.C. which added roughly 850 MMcfd, increasing system capacity to 1094 MMcfd. In 1998, Foothills completed an expansion of its Eastern Leg facilities in Saskatchewan which represented the largest system expansion, increasing contract capacity to 2.2 Bcfd.

- As a result of market conditions in the U.S. lower 48, the completion of Phase II of the ANGTS has been deferred. Recent events and prospects for higher gas demand in the lower 48 make construction of the northern segments of the project more likely than at any time since the early 1980's. The ANGTS sponsors remain committed to completing Phase II in a timely manner. Sponsors continue to take appropriate actions and expend funds necessary to maintain the ANGTS regime in a state of readiness including efforts focused upon substantially reducing the cost of transporting Alaskan North Slope gas to market.

- Since the inception of the project, the ANGTS sponsors have made substantial progress toward the eventual completion of the ANGTS. Right-of-way permits and easements have been granted and their terms extended where necessary for much of the system; a broad array of regulatory authorizations have been issued by Canadian and U.S. regulatory authorities; and the U.S. Congress has approved waivers of law. In 1992, the Canadian government and Foothills extended the term of the Easement Agreement in Yukon for twenty years at a minimum.

- In January, 1988, President Reagan issued a finding that exports of Alaskan gas would not decrease the quantity, nor increase the price, of energy available to the United States. However, the finding reaffirmed the President's support for the unique regulatory treatment of the Prebuild Project. The finding also indicated that the President still supported the completion of the ANGTS.

- In January, 1992, the U.S. Federal Inspector for the ANGTS, sent the President a report which recommended abandonment of the entire ANGTS legal infrastructure, including the bilateral agreement with Canada. While the ANGTS sponsors did not object to abolition of the Office of the Federal Inspector, they strongly opposed abrogation of the core ANGTS authorities – i.e., the Alaska Natural Gas Transportation Act, the President's 1977 decision, and the bilateral agreement with Canada. Although the Office of the Federal Inspector was dismantled, that authority now resides with the Department of Energy. The recommendation to abandon the ANGTS legal infrastructure was rejected.

- On June 30, 1999, the Federal Energy Regulatory Commission issued an "Order Accepting and Suspending Tariff Sheets, Subject to Refund and Hearing" in the 1999 Northern Border Pipeline Company Rate Case. The Order included a statement that the "ANGTS is no longer viable". Foothills requested clarification of that statement, arguing that it was not only factually incorrect, but counter to important commitments which have been made by the United States government to the Canadian sponsors and the Canadian government regarding the ANGTS. The

Canadian Government also requested that the FERC clarify its statement to avoid creating uncertainty with respect to the U.S. commitments to its treaty with Canada and the ANGTS. The FERC subsequently clarified the order consistent with the request of Foothills and Canada in an expeditious manner.

- The Canadian and U.S. governments and their agencies have consistently supported the Prebuild and completion of the ANGTS in accordance with the Canada/U.S. Agreement.

- As the Canadian sponsor of the ANGTS and a partner in the Alaskan segment of the Project, Foothills believes that it is important for public and private parties to be familiar with the history of the project, the benefits of the Prebuild Phase, and the steps to complete the remainder of the system in the years ahead. Accordingly, this briefing document has been prepared.

II. BACKGROUND

Controversy over the best means of transporting Alaskan gas to markets in the lower forty-eight states began as early as the late 1960's, when extensive oil and gas reserves were first discovered in the area of Prudhoe Bay. For purposes of this discussion, however, it is sufficient to begin with the Alaska Natural Gas Transportation Act ("ANGTA"), which was passed by the U.S. Congress and signed into law in 1976.[1]

Through ANGTA, Congress sought to ensure that the construction and operation of an Alaska natural gas transportation system would not be delayed by the type of administrative and judicial problems which had plagued the trans-Alaskan oil pipeline and other major energy projects during the early 1970's. To that end, ANGTA established a special procedural framework which would permit the U.S. President and the Congress to make a final decision on an Alaska natural gas transportation system, but only after substantial input from other U.S. agencies and interested parties. Among other things, the Act specifically provided for:

(a) a recommendation to the President from the Federal Power Commission ("FPC"), which was the predecessor to the Federal Energy Regulatory Commission ("FERC");

(b) an opportunity for other U.S. agencies, states, and interested parties to comment on the recommendation;

(c) a Presidential decision and report to Congress on an Alaskan natural gas transportation system; and

(d) Congressional review of the Presidential decision.

ANGTA also established specific procedures to prevent undue governmental delay in achieving the most expeditious completion of the transportation system ultimately approved by the President and Congress. In particular, U.S. regulatory agencies are required to expedite all proceedings relating to the construction and initial operation of the system; U.S. officials are prohibited from taking any action which would either change the basic nature and general route of the chosen system or impair its expeditious completion; and the scope of judicial review of regulatory actions relating to the chosen system is severely limited.

<u>III. THE DECISIONAL PROCESS IN CANADA AND THE UNITED STATES</u>

At the time of ANGTA's enactment, comparative hearings were in progress before the FPC on three competitive proposals for an Alaska natural gas transportation system. Specifically, those proposals were:

(1) the <u>Arctic Gas Project</u>, which proposed an overland pipeline extending from Prudhoe Bay, across the North Slope of Alaska to the Canadian Mackenzie Delta, and thence southerly through Canada to the lower forty-eight states;

(2) the <u>El Paso LNG Project</u>, which proposed an overland pipeline extending from Prudhoe Bay to southern Alaska, where the gas would have been liquefied and transported by tankers to terminals in the western United States; and

(3) the <u>Alcan Pipeline Project</u> – referred to in Canada as the <u>Alaska Highway Pipeline Project</u> – which proposed an overland pipeline extending from Prudhoe Bay to Fairbanks, Alaska, and thence southeasterly through western Canada to the lower forty-eight states.

Two of these proposals – namely, the Arctic Gas Project and the Alaska Highway Pipeline Project (or Alcan Pipeline Project) – were also pending before the Canadian National Energy Board ("NEB") at the time of the enactment of ANGTA. The El Paso LNG Project was not before the NEB because it was an "all American" project which did not propose a pipeline across Canada.

However, Canadians were concerned about a LNG route along the west coast of Canada.

A. The Recommendation of the FPC

On May 1, 1977, following extensive hearings in which every facet of the competitive proposals was explored, the FPC issued its Recommendation To The President. In that recommendation, the four sitting commissioners unanimously agreed that it would be in the public interest of the United States to construct an overland pipeline for the transportation of Alaskan gas to markets in the lower forty-eight states.[2] As to which overland system should be selected, however, there was initially a split of opinion. Two commissioners unconditionally recommended the Alcan project. The other two stated that if the Government of Canada selected the Alcan route, the Alcan project should be approved.

B. The Reasons For Decision Of The Canadian NEB

On July 4, 1977, following two years of competitive hearings which had paralleled the hearings before the FPC, the NEB issued its Reasons for Decision, Northern Pipelines. In that decision, the NEB rejected the Arctic Gas proposal and recommended an overland pipeline to the Canadian Governor-in-Council.

The NEB's decision was also important because it indicated that international approval of the Alaska Highway Pipeline Project might provide a basis for making additional Canadian gas available to the United States prior to the flow of Alaskan gas. Specifically, the NEB stated:

> "Assuming ... that Alaska gas is to be connected to markets by a land bridge through Canada, it could be

> possible to pre-build some of the southern Canada and northern United States pipeline capacity to market gas which may be surplus to Canada's requirements in the late 1970's and early 1980's."[3]

As discussed more fully below, this concept of "pre-building" certain portions of the system, in order to provide the United States with early deliveries of Canadian gas to satisfy lower 48 market needs, was considered to be one of the principal advantages of the Alaska Highway Pipeline Project when it was approved by the United States.

C. The Transit Pipeline Treaty

The large discoveries of hydrocarbon supplies in Alaska and the anticipated use of pipelines across Canada to access these reserves as well as Canada's use of U.S. pipelines as a conduit to connect Canadian markets led Canadian and U.S. authorities to develop a treaty providing for non-discriminatory treatment. In September, 1977, the "Transit Treaty" was signed which effectively provides that neither country will interfere with the transportation of hydrocarbons regardless of source or market and will not impose any discriminatory tax or monetary charge which does not apply to similar pipelines used for domestic transportation.

D. The Agreement Between Canada And The U.S.

Following the consummation of the Transit Pipeline Treaty and the issuance of the FPC and NEB recommendations, officials of the Canadian and United States governments began negotiations in the summer of 1977 to determine whether an overland pipeline through Canada could be finally approved on terms and conditions acceptable to both countries. As a result of these negotiations, the two countries, on September 20, 1977, signed an

"Agreement Between Canada and the United States of America Applicable to a Northern Natural Gas Pipeline."[14] This agreement endorsed the Alaska Highway Pipeline Project, set out the general routing for the Project and designated Foothills Pipe Lines Ltd. ("Foothills") as the Canadian sponsor and the ANNGTC as the sponsor of the Alaskan segment. Northern Border Pipeline Company and the Pacific Gas Transmission Company were identified as lower 48 sponsors. It also committed the United States and Canadian governments to discharge their regulatory responsibilities in a manner that would facilitate the expeditious construction of the project in accordance with the terms of the agreement. The Agreement has an initial term of 35 years and continues beyond 2012 unless terminated on one year's notice by either party.

E. The U.S. President's Decision and Report to Congress

On September 22, 1977, as required by ANGTA, the President issued his Decision and Report to Congress on the Alaska Natural Gas Transportation System. In that decision, the President determined that it was in the best interest of the American people to have the Alaskan gas reserves transported to market at the earliest possible date. He further determined that the project identified in the Canada/U.S. Agreement was the most economic and environmentally sound means of accomplishing this goal.

In its discussion of the advantages of the ANGTS as compared to the other competing proposals, the President's Decision emphasized that the system would:

> " ... provide the opportunity to obtain additional gas at an earlier date by early construction of portions of the southern Canadian and lower 48 sections of [the system] ... with delivery of gas from Alberta (where

> there is a temporary excess supply) in advance of the delivery of Alaska gas."[5]

The Decision further recognized that:

> "A pre-delivery arrangement involving Alberta gas would provide stimulus to exploration for additional supplies in that province by providing producers with additional markets for their gas."[6]

Having selected the ANGTS, the President's Decision specifically identified the facilities to be constructed by the sponsors of the project. In accordance with the Agreement, Foothills was identified as the company responsible for the construction and operation of the Canadian segment of the project.

F. U.S. Congressional Approval Of The ANGTS

On November 2, 1977, the U.S. Congress passed a joint resolution which ratified the President's Decision.[7] With the signing of this resolution by the President on November 8, 1977, the complicated process of selecting an Alaskan natural gas transportation system came to an end in the United States.

G. Certification Of The ANGTS By The FERC

In view of the President's Decision and the ratification of that decision by Congress, the FERC issued an order on December 16, 1977, which, among other things, granted certificates of public convenience and necessity to Alcan Pipeline Company, Northern Border Pipeline Company ("Northern Border"), and Pacific Gas Transmission Company ("PGT").[8] These certificates were subject to the satisfaction of certain conditions related to construction costs and schedule, finance and environment. Alcan's certificate for the Alaskan segment of the ANGTS was subsequently transferred to its successor-in-interest, Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest"),[9] which has remained the sponsor of the Alaskan segment of the project.

H. The Canadian Northern Pipeline Act

On April 4, 1978, the Northern Pipeline Act was passed by the Canadian Parliament and proclaimed on April 12, 1978.[10] Among other things, the Act granted certificates of public convenience and necessity to the Foothills subsidiaries responsible for constructing the Canadian segment of the ANGTS. In addition, the Act established the Northern Pipeline Agency, with the authority to oversee the construction of the system in Canada. The Agency was established as a single window for regulatory oversight of the project in order to co-ordinate and facilitate expeditious project approvals.

Similar to the United States, conditions were placed on the certificate. These conditions exhibit the inherent flexibility necessary for the certificates to be responsive to conditions which exist at the time the project proceeds. Again, as in the United States, the certificates do not have a sunset clause.

I. The 1981 Waiver of Law

By 1981, it had become increasingly apparent that the 1977 Presidential Decision and the U.S. Natural Gas Act contained certain provisions which were obstacles to the private financing of the ANGTS. In keeping with its commitments to the project, however, the U.S. Congress, at the request of the President, passed a resolution in late 1981 which waived these provisions, thereby paving the way for the remainder of the project to be financed as soon as the U.S. market requires Alaskan gas. Subsequently, the waiver of law was challenged, but it was upheld by the United States Court of Appeals.[11]

In summary, the 1981 waiver of law eliminated essentially four hurdles at that time to the financing of the remainder of the ANGTS. First, it permitted the North Slope producers to participate in the ownership of the ANGTS. Second, it included the North Slope conditioning plant as an integral part of the overall ANGTS, which is entitled to special protections under ANGTA. Third, it authorized the FERC to approve payment of Foothills' cost of service as soon as the Canadian segment of the project is capable of operation provided that such date is not before a date certain established in FERC's final certificate for the completion of the entire system. Finally, the waiver prohibited the FERC from changing the provisions of final rules and orders approving any tariff in any manner that would impair the recovery of operation and maintenance expenses, actual current taxes, and amounts necessary to service debt for the ANGTS. The Waiver is permissive in nature, allowing the implementation of these provisions, while not precluding the negotiation of alternative commercial arrangements.

IV. THE ANGTS PREBUILD PROJECT

A. The Prebuild Contracts

Consistent with the desire to have the southern portions of the ANGTS prebuilt in order to transport Canadian gas in advance of Alaskan gas, Pan-Alberta signed two contracts in 1978 under which it agreed to supply Northwest Alaskan Pipeline Company ("Northwest Alaskan") with approximately 1.04 Bcf of new Canadian gas exports per day over a twelve-year period. Under the Eastern Leg contract, Pan-Alberta agreed to sell Northwest Alaskan approximately 800,000 Mcf per day, to be delivered at a point on the international border near Monchy, Saskatchewan. Northwest Alaskan, in turn, contracted to resell 200,000 Mcf per day of this volume to Northern, a Division of Enron Corporation, 150,000 Mcf per day to Panhandle, and 450,000 Mcf per day to United. Under the Western Leg contract, Pan-Alberta agreed to sell Northwest Alaskan approximately 240,000 Mcf per day, to be delivered at a point on the border near Kingsgate, British Columbia, for resale to PIT. PIT, in turn, contracted to resell the Western Leg volumes to SoCal.

To assemble the necessary gas supply for the eastern and Western Leg sales, Pan-Alberta entered into over 800 gas purchase contracts with approximately 420 Alberta producers, who, collectively, committed over 5 Tcf of proven Alberta gas reserves to the project. In addition, Pan-Alberta contracted with NOVA for the construction of certain Prebuild-related pipeline facilities, and for the transportation of the Prebuild volumes from numerous Alberta gas fields to various interconnections with the Foothills system. Pan-Alberta also contracted with Foothills for the transportation of the gas from NOVA's facilities to the eastern and Western Leg delivery points on the U.S. border.

The Prebuild import and resale contracts were designed from the outset to provide a constant source of assured revenue from which Pan-Alberta would be provided with sufficient funds to satisfy its financial obligations to Foothills, NOVA, and the hundreds of producers whose participation was vital to the project. To this end, the gas sales contracts between Pan-Alberta and Northwest Alaskan required Northwest Alaskan to take and pay annually for 85% of the annual contract quantities, and to take and pay daily for 50% of the daily contract quantities. In addition, identical take-and-pay levels were included in the resale contracts between Northwest Alaskan and its downstream pipeline purchasers (Northern, Panhandle, United, and PIT). For all practical purposes, Northwest Alaskan's resale contracts were mirror images of its import contracts with Pan-Alberta.

B. Canadian And U.S. Prebuild Regulatory Approvals

In 1978, applications for approval of the Prebuild project were filed with the NEB in Canada and FERC in the United States. Soon thereafter, the NEB and FERC conducted extensive hearings in which every facet of the project, including the terms and conditions of the gas sales and resale contracts, was examined in detail.

Based upon the record established in these hearings, the FERC issued an order on January 11, 1980, approving the Prebuild imports and related sales and tariff arrangements for the Western Leg of the ANGTS.[12] Striking a theme that would be repeated subsequently in virtually every FERC order regarding the matter, the FERC found that the Prebuild Project was not only related to the construction and initial operation of the ANGTS, within the meaning of ANGTA, but would also create substantial benefits with respect to the financing and ultimate completion of the entire system.[13] Among other things, the FERC concluded that prebuilding would (1) reduce the future transportation costs of Alaskan gas; (2) get the ANGTS project started sooner than would otherwise be the case; (3) spread the demand for labor, capital, and material over a longer period; and (4) facilitate the financing of the ANGTS.[14]

On April 28, 1980, the FERC issued an order approving the Prebuild imports and related sales and tariff arrangements for the Eastern Leg of the ANGTS.[15] Reaffirming its prior findings regarding the tangible benefits of prebuilding the Western Leg, the FERC stressed that the benefits would "be even greater with respect to prebuilding a portion of the Eastern Leg, since more of the Eastern Leg of the ANGTS is to be prebuilt ...."[16]

In the April 28 order, however, the FERC determined that the annual and daily minimum take provisions in the Prebuild contracts should be limited by an appropriate condition, because these provisions would otherwise constrain the ability of the U.S. purchasers to reduce their takes during periods, if any, when the gas was not priced competitively with alternate fuels. At the same time, however, the FERC recognized that a guaranteed minimum revenue stream was absolutely essential to the financing of production, plant, gathering, and pipeline facilities required for the Prebuild Project.[17] To reconcile these dual objectives, the FERC simply required, as a condition to its import authorizations, that the minimum take provisions of the contracts be modified in a manner that would limit the financial exposure of the U.S. purchasers to a fixed amount of money per year or per day, as appropriate.[18] Explaining this "limiting mechanism", the FERC stated:

> "Rather than specify that the U.S. purchasers must take and pay for minimum quantities of gas, the Commission's alternative would specify that they would have to take and pay for enough gas to provide an assured minimum amount of revenue ....
>
> Under this modification, the obligation of the U.S. purchasers to take gas would go down if the border price went up. However, the purchasers would always be obliged to take enough gas to provide the established minimum revenue." (emphasis added).[19]

Significantly, the FERC went so far as to emphasize that its condition:

> " ... effectively assure[d] the Canadian producers of sufficient revenue to finance gathering and conditioning facilities even in the event that the delivered gas is not competitively priced." (emphasis added).[20]

While the April 28 order was thus replete with statements that the minimum revenue stream would be assured or guaranteed, the discussion on tracking of project costs in the shippers' rates contained an anomalous statement which appeared to contradict the FERC's assurances. Specifically, that section of the order stated:

> " ... [A]n evaluation for consistency with the public interest should be made each time there is a price change for a particular source of imported gas. ... [T]he Commission would expect that different terms and conditions would be appropriate to govern a particular source of gas imports at different levels of the price for that source.[21]

With the uncertainty created by this statement, the financial viability of the ANGTS Prebuild Project was placed in jeopardy. Moreover, without proof of financing, Foothills could not obtain the necessary authorizations from the NEB to proceed with construction of the Canadian segment of the project. On May 9, 1980, the NEB publicly announced that the uncertainty created by the FERC's April 28 order ("it could cause doubts in the perceptions of investors") precluded the NEB at that point from making the requisite findings under Condition 12 of the Northern Pipeline Act, as amended,[22] that financing had been obtained for the Prebuild Project and could be obtained for the remainder for the ANGTS.[23] For this reason, the NEB emphasized that it would be desirable for the FERC to reconsider the minimum payment condition of the April 28 order, particularly in light of the Canadian investments which would be required for the project.[24]

In view of these concerns, Foothills and Pan-Alberta filed a joint petition for rehearing on May 28, 1980, urging, among other things, that the FERC renounce any right to unilaterally modify the pricing regime of the Prebuild imports on the basis of future developments. Referring to the above-quoted statement from the April 28 order, Pan-Alberta and Foothills stated:

"This perplexing statement suggests that the Commission or ERA would not only be able to modify the terms and conditions of the import permit, but, indeed, 'would expect' such modifications, each time the Canadian border price is changed – an event which could occur several times during the life of the exports. If this is the Commission's intent, the promise of an 'assured' revenue stream is empty and without significance. What is more important, it clearly provides no basis upon which the Canadian sponsors can secure the gas supply and financing which are required for the project ..."

"To eliminate the uncertainty created by the April 28 order and to establish a proper frame-work for financing, the Commission's order on rehearing should state unequivocally that neither the principles upon which the revenue ceilings are calculated, nor any other provisions which are critical to financing, will be modified during the term of the exports." (emphasis added).[25]

In its June 20, 1980 order on rehearing, the FERC responded favorably to the request of Foothills and Pan-Alberta, and agreed that it would be inappropriate to periodically reconsider the minimum revenue stream. Accordingly, the FERC provided:

" ... the assurances sought by Foothills and Pan-Alberta that it ... [would] not change the principles upon which the revenue stream is calculated during the authorized term of the imports reaffirmed herein." (emphasis added, footnote omitted).[26]

In response to the apprehensions expressed by the Canadian participants, the FERC emphasized that its minimum take condition should not be viewed as a "ceiling" or a "cap" on revenues, but, rather, as "a floor, beneath which the revenues will not be allowed to fall."[27] Moreover, the FERC reiterated its prior statement from the April 28 order that the condition would assure sufficient revenue to the Canadian participants "even in the event that the delivered gas is not competitively priced."[28]

With these commitments, the FERC's order of June 20, 1980 eliminated a major hurdle to the financing of the Prebuild phase of the ANGTS. However, under a proposed amendment to Condition 12 of the Northern Pipeline Act to take into account the financing of the Prebuild, construction of that segment of the overall project could not be authorized until the NEB and the Minister responsible for the Northern Pipeline Agency were satisfied that the Prebuild was financed and financing could be obtained for the remainder of the system[29]. In short, Canada indicated that it required assurances reaffirming the commitment of the United States government to the completion of the entire ANGTS in accordance with the 1977 Agreement.

The President and Congress acted swiftly to provide the assurances required for Canadian participation in the project. Specifically, on July 1, 1980, Congress passed a Joint Resolution which reaffirmed congressional support for the ANGTS (Appendix A). After finding that prebuilding would "enable this Nation to obtain Canadian natural gas to displace two hundred thousand barrels of foreign oil per day," the Joint Resolution declared that "it is the sense of the Congress that the [ANGTS] System remains an essential part of securing this nation's energy future and, as such, enjoys the highest level of Congressional support for its expeditious construction and completion ...". Moreover, on July 18, 1980, President Carter wrote Prime Minister Trudeau a letter expressing the United States' support for prebuilding and the completion of the remainder of the ANGTS. After briefly reviewing the progress achieved in the U.S. towards completion of the ANGTS, the President stated:

> "I trust these recent actions on our part provide your government with the assurances you need from us to

> enable you to complete the procedures in Canada that are required before commencement of construction on the Prebuild sections of the pipeline." (Appendix B).

Based upon the commitments of the FERC, the President, and the Congress, the NEB issued a decision in July 1980 finding that if the amended Condition 12 were approved by the Government, the NEB was satisfied its provisions could be met. With respect to the financeability of the Prebuild Project, the NEB placed great reliance on the guarantees set forth in the FERC's June 20, 1980 order on rehearing. Specifically, the NEB noted:

> " ... [T]he Board was concerned whether the F.E.R.C. requirement of a minimum payment for Alberta gas transmitted on Prebuild facilities, instead of the take and pay provisions in the Pan-Alberta contract, would adversely affect the financeability of the pipeline. ... It did not incorporate the current border price for Canadian gas exports in the formula, as the Board would have preferred, but it did provide for escalation in the U.S. $3.45 price and pointed out that it was a 'floor' and in no way precluded imports at higher prices. Foothills (Yukon) has now indicated that it is satisfied with the F.E.R.C. decision .... The Board also is satisfied that the F.E.R.C. decision is not an obstacle to financing. ... [O]n the basis of the foregoing the Board ... [finds that] ... the company has established to the satisfaction of the Board that financing has been obtained for that portion of the pipeline, hereinafter referred to as the prebuild sections ...." (emphasis added).

Following the NEB's decision, the Governor-In-Council approved the amendment to Condition 12 of the Northern Pipeline Act, an amendment which was required for the Prebuild Phase to go forward. In addition, the Minister responsible for the Northern Pipeline Agency concurred with the NEB's finding that the financing requirements of Condition 12, as amended, had been satisfied.

C. Construction Of The Prebuild

Subsequent to the Canadian government's approval of the Prebuild Project, Foothills invested approximately one billion dollars in prebuilding 528 miles of the 2000-mile Canadian segment of the ANGTS; NOVA invested approximately $500 million in providing capacity within its intraprovincial pipeline system to transport the Prebuild volumes from numerous Alberta gas fields to interconnections with the Foothills system; and Alberta producers invested approximately $1 billion in the construction of necessary production and gathering facilities. In total, approximately $2.5 (Can.) billion was invested by the Canadian natural gas industry in order to provide a service which had been found by the FERC, the Congress, and the President to be crucially required by the public interest of the United States.

There was also substantial Prebuild investment in the United States. Specifically, Northern Border invested approximately $1.3 billion (U.S.) in the construction of 823 miles of the Eastern Leg of the Prebuild Project. In addition, PGT and Northwest Pipeline Corporation ("Northwest") invested approximately $323 million (U.S.) in the construction of the Western Leg.

Significantly, the Prebuild Phase of Foothills' system was constructed within cost estimates and was completed on schedule. As a result, deliveries began on the Western Leg in late 1981 and on the Eastern Leg in 1982.

Foothills has continued to construct additions to the Prebuild to accommodate the demand for gas in the United States. In 1993, Foothills increased capacity on the Western Leg to roughly 1.1 Bcf/d and in 1998 expanded the Eastern Leg to approximately 2.2 Bcf/d. Both expansions were performed under the provisions of the Northern Pipeline Act, meeting all conditions under the Act including all socio-economic and environmental conditions existing at the time of the expansions. The ANGTS regime has exhibited its ability to respond to the "standards of the day".

D. Subsequent Prebuild Developments

Subsequent to its construction and placement into service, there have been numerous developments relating to the Prebuild Project. One of the most significant developments was the renegotiation of the Prebuild contracts in 1984, following the establishment of a new pricing policy by the Canadian government which granted Canadian exporters and their U.S. buyers greater freedom to agree upon the prices and other terms of their gas supply arrangements. The renegotiated contracts were designed to provide greater responsiveness to market conditions, while simultaneously preserving the minimum revenue stream which underpins the financial integrity of the Prebuild Project. These new arrangements were approved in the United States by both the Economic Regulatory Administration ("ERA") and the FERC. In both approvals, the agencies recognized the unique nature of the ANGTS and the necessity to protect the minimum revenue stream underpinning the Prebuild Project.[30]

These contracts have subsequently been renegotiated several times, each receiving approval in the United States. Another significant development occurred in 1989 when a multi-party settlement was consummated in order to relieve United of its contractual obligations relating to the Prebuild Project. As part of that settlement, United's equity interest in Northern Border was transferred to a subsidiary of Northern Natural; United's gas purchase obligation with Northwest Alaskan was assigned to NATGAS U.S. Inc. ("NATGAS"), a

Pan-Alberta subsidiary which is now known as Pan-Alberta Gas (U.S.) Inc.; NATGAS succeeded to United's transportation capacity on Northern Border; and Northern Natural agreed to purchase certain volumes from NATGAS. On December 21, 1989, the FERC approved the comprehensive settlement, recognizing once again the unique nature of the ANGTS and the necessity of protecting the minimum revenue stream which generally underpins the project.

The FERC has also reaffirmed the special treatment of the ANGTS Prebuild Project in various proceedings in which is has considered generic rules or policies. In Order No. 380-A, for example, the FERC exempted the Prebuild contracts from a generic rule which prohibits minimum take or minimum purchase obligations in pipeline tariffs[31]. Explaining its action, the Commission stated:

> "The ANGTS is a unique international project whose ultimate success has always rested on a framework of mutual trust and cooperation between the governments of the U.S. and Canada. It is abundantly clear that the assurances made by the Commission, the Congress, and the President collectively comprise a commitment to protect the stream of revenue underpinning the financing of the Canadian segment of the ANGTS, that the Government of Canada relied on those assurances, and that any subsequent action that could adversely affect that stream of revenue would constitute a breach of faith in our nation's relationship with Canada."[32].

The FERC's exemption of the Prebuild tariffs from the minimum commodity bill rule, as well as numerous other aspects of that rule, were appealed to the United States Court of Appeals for the District of Columbia Circuit. The court ringingly affirmed the Prebuild exemption, however, noting that the Commission's 1980 orders had "crafted a contract formula that guaranteed the Canadian suppliers an adequate revenue stream generated from United States sales ... to support the financing of the ANGTS ...[33]. More importantly, the court emphasized that "[a]pplications of the rule to... [the Prebuild tariffs] would have placed the United States in breach of its explicit commitments to Canada."[34].

The FERC also agreed in Opinion No. 256-A that its general policy against as-billed flow-through of Canadian gas costs would not apply to the Prebuild Project. Specifically, the FERC stated:

> "[W]e do not intend to 'depart from previous orders of the Commission regarding the assurances for the revenue stream of the ANGTS pre-built project'...[W]e believe special treatment for Alaskan gas and Canadian gas related to the protected stream of revenue is fully warranted by the sui generis nature of ANGTS as we have fully discussed in other Commission orders."[35].

In addition, in Order No. 636-A, the Commission explained that nothing in its new regulations relating to the restructuring of the natural gas industry was intended "to disturb the United States government's commitment to the ANGTS Prebuild."[36] Furthermore, in an order updating the Commission's filing requirements in light of Order No. 636, the Commission proposed to delete certain regulations applicable to the ANGTS, explaining that they were obsolete in the post-Order No. 636 environment.[37] In doing so, however, the Commission stated that:

> "*Nonetheless, the Commission remains ready to facilitate the construction of ANGTS, which Congress has found to be in the public interest.* Hence, if action is warranted in the future to facilitate financing and progress on the ANGTS and the recovery of ANGTS costs, the Commission will act expeditiously. What

> was stated in Order No. 636-A applies here as well: 'nothing in the rule [Order No. 636] is intended to disturb the United States government's commitment to the ANGTS prebuild.[38]

As to Northern Border, the Commission has stated that it "continues to view the Northern Border prebuild segment as remaining subject to the various agreements between the United States and Canadian governments and subsequent findings in Commission orders certificating Northern Border Pipeline Company's system."[39] In addition, the Commission stated that "[t]he United States, like Canada, is bound by the 'Agreement on Principles' concerning the ANGTS. By virtue of the 'Agreement' which has the force and effect of a treaty, the Commission may not alter the viability of the ANGTS by changes in previously granted orders."[40]

In 1998, the Commission reaffirmed its commitment to the ANGTS project in an order approving a settlement to implement the restructuring of gas sales and transportation arrangements among various parties regarding the Western Leg of the Prebuild system. There, the Commission continued to recognize the unique status of the Prebuild Project and specifically cited to the Commission's reaffirmation of its commitment to the project stated in Order No. 636-A, discussed above.[41]

In short, while the ANGTS, including the Prebuild, has continued to evolve in light of market realities, the contracts underpinning the project, as well as the government approvals of those contracts, have continued to ensure the financial integrity of the project.

V. PRESIDENTIAL FINDING ON ALASKAN GAS EXPORTS

In the summer of 1987, the Canadian government was apprised that the U.S. President was considering the issuance of a finding in favor of exports of Alaskan gas. Thereafter, at the request of the Canadian government, consultations were held between Canadian and U.S. officials where Canadian officials expressed deep concern about the impact of such a finding on the ANGTS and the Agreement.

On January 13, 1988, the U.S. President issued a finding relating to potential exports of Alaskan gas. Significantly, however, the President took that opportunity to reaffirm his support for unique regulatory treatment of the ANGTS Prebuild Project. Specifically, the President stated: " ... I want to reaffirm our support for the special regulatory treatment of the Prebuild portion of the ANGTS, including the minimum revenue stream guarantees."

With this finding, the U.S. President has continued a policy which has been applied to the Prebuild Project since its inception. In short, the Prebuild Project remains an integral part of a unique system – i.e., the ANGTS – and, therefore, it is entitled to unique regulatory protection.

The President also stated he did not believe that this finding should hinder the completion of the ANGTS.

VI. COMPLETION OF THE ANGTS

Since the project's inception, the ANGTS sponsors have made substantial progress toward the completion of Phase II of the project. Among other things, right-of-way permits for the Alaskan segment have been issued by the U.S. Department of Interior; a broad array of design approvals and environmental authorizations have been issued by U.S. and Canadian authorities; the FERC has established rules and regulations for the tracking of Canadian ANGTS charges; and Congress has approved waivers of law.

In addition, an easement agreement was executed in 1983 between the Government of Canada and the Foothills subsidiary responsible for construction of the segment of the ANGTS in Yukon Territory. The term of the easement is for 25 years with a renewal at the option of the company for an additional 24-year period. The easement agreement is subject to obtaining the consent of the Minister responsible for the Northern Pipeline Agency prior to commencing construction activity. On November 4, 1992, the timeframe within which the consent is to be obtained was extended to September 20, 2012.

Notwithstanding this regulatory progress, the financing and construction of Phase II of the ANGTS has been temporarily delayed as a result of the market conditions in the lower 48. It now appears that the project will be required this decade. The ANGTS sponsors remain committed to completing the project in a timely manner. The sponsors continue to take appropriate actions and expend funds necessary to maintain the ANGTS regime in a state of readiness, including the federal right-of-way grant, Section 404 permits and the broad array of legal and regulatory authorizations and treaties that have been issued by Canadian and U.S. authorities. Furthermore, the sponsors have continued to expend effort toward significantly reducing the cost of transporting Alaskan Northern Slope gas to market.

Recent years have seen a decline in both inflation and the cost of capital, and advancements in pipeline technology have also occurred. In 1987, in response to these changes and the need to update the earlier cost estimate developed in 1982, Foothills and Alaskan Northwest agreed to complete a detailed re-estimate of Phase II of the ANGTS. On June 6, 1988, this re-estimate was publicly released showing an approximate 45% reduction in the project capital costs. In 1999, Foothills again significantly reduced the capital cost estimate for the Project. Foothills continues to examine further opportunities for cost reductions and efficiencies toward achieving the most cost effective transportation of northern frontier gas reserves.

While the precise date for moving forward with the financing and completion of Phase II remains to be finalized with stakeholders, for several reasons Foothills believes that Alaskan gas will be needed in the lower forty eight states much sooner than many have anticipated. First, Alaskan gas is a secure U.S. domestic resource which can reduce dependence on imported oil. The proven gas reserves exceed 30 trillion cubic feet and estimates of potential reserves are approximately 100 trillion cubic feet. Second, there is increasing uncertainty in the ability of existing basins to keep pace with gas demand which is estimated to reach 30 trillion cubic feet per year in this decade. This demand may well occur earlier in that time frame, hastening the requirement for Alaskan gas to serve energy needs in southern markets. With its advanced state of readiness, the ANGTS is positioned to meet an expeditious delivery timeframe.

To further underscore its commitment to the ANGTS, Foothills is a partner in Alaskan Northwest Natural Gas Transportation Company, the U.S. partnership which is responsible for the construction and operation of the Alaskan segment of the project. In 1990, Foothills purchased the outstanding shares in United Alaska Fuels Corporation, a subsidiary of United. At the end of 1994, Foothills increased its partnership share. TransCanada PipeLines Ltd. holds the other active partnership interest. Foothills' participation in the Alaskan Northwest partnership is expected to improve U.S.-Canadian cooperation and coordination in the completion of the project.

Foothills remains prepared to proceed with the financing and completion of Phase II as soon as Alaskan gas is required by the markets in the lower forty-eight states and is taking active steps to further the progress of the Project. In the meantime, the continuing commitments by the governments of both Canada and the United States to the international Agreement provide an important foundation for the early completion of this important bilateral project.

VII. THE BAYER REPORT

On January 24, 1992, Mr. Michael J. Bayer, the U.S. Federal Inspector for the ANGTS, sent President Bush a report which recommended that the United States abandon support for the completion of the ANGTS. Among other things, Mr. Bayer's recommendations included: 1. "Repeal the Alaskan Natural Gas Transportation Act"; 2. "Eliminate the exclusive ANGTS route to transport Alaskan North Slope gas to the lower 48"; 3. "Eliminate the ANGTS project sponsors unique legal monopoly status"; 4. Withdraw the President's 1977 decision under the Act; 5. Terminate all bilateral agreements with Canada relating to the ANGTS; and 6. Abolish the Office of Federal Inspector ("OFI"). None except the last recommendation was accepted.

The ANGTS sponsors did not oppose the abolition of OFI. They strongly opposed, however, the implementation of Mr. Bayer's other recommendations. The sponsors believed it is in the best interests of both the United States and Canada to retain ANGTA, the President's 1977 Decision, and the bilateral agreements relating to the ANGTS. These core ANGTS authorities are vital to the completion of the project as soon as warranted by the market.

On February 14, 1992, the Government of Canada also objected to most of Mr. Bayer's recommendations. In a diplomatic note sent to the U.S. Department of State, the Canadian government stated that implementation of certain recommendations - such as the repeal of ANGTA, the withdrawal of the President's 1977 decision, and the termination of U.S.-Canadian agreements relating to the ANGTS – would be unacceptable to Canada and contrary to the obligations of the United States.

On March 12, 1992, Senator Bennett Johnston, Chairman of the Senate Committee on Energy and Natural Resources, sent a letter to the President expressing his opposition to the Bayer recommendations. Senator Johnston emphasized that, while the ANGTS has been delayed as a result of current market conditions, it is clear that American consumers will eventually need access to North Slope gas. He further emphasized that the ANGTS is still the most economic and environmentally sound means of providing that access. While the Office of the Federal Inspector ("OFI") has been dismantled, the OFI authority resides with the Department of Energy and the other recommendation to abandon the ANGTS legal infrastructure was rejected.

VIII. 1999 NORTHERN BORDER RATE CASE

On June 30, 1999, the Federal Energy Regulatory Commission issued an "Order Accepting and Suspending Tariff Sheets, Subject to Refund and Hearing" in the 1999 Northern Border Pipeline Company rate case. The June 30 Order included a statement that the "ANGTS is no longer viable." Foothills subsequently requested clarification of that statement, arguing that it is not only factually incorrect, but is counter to important commitments which have been made by the United States government to the Canadian sponsors and the Canadian government regarding the ANGTS.

Specifically, Foothills argued that there is no evidence in this or any prior record to support the Commission's statement. Significantly, no party raised the assertion in this case. As reported in ANNGTC's 1999 FERC Form No. 2, "[T]he [ANNGTC] Partnership intends to continue to take steps necessary in order to advance its project in a timely fashion."[42] Furthermore, the United States government has repeatedly and consistently supported the ANGTS and acknowledged the unique status of the project. Accordingly, Foothills argued that the Commission's statement that the "ANGTS is no longer viable" breaches Section 9(d) of the Alaska Natural Gas Transportation Act, 15 U.S.C. § 719g(d) (1994), and violates the "Agreement on Principles Applicable to a Northern Natural Gas Pipeline" consummated by the U.S. and Canada ("U.S.-Canadian Agreement"). As the Commission has recognized, "both governments [*i.e.*, the U.S. and Canada] remain bound by the 'Agreement on Principles' concerning the ANGTS. The 'Agreement on Principles' has the force and effect of a treaty between the two nations. The U.S. government (in this instance the Commission) is bound to not alter the project's viability by changes in previously granted orders."[43] The Commission had no basis in law or fact to conclude that the ANGTS is no longer viable.

Foothills requested that the Commission clarify this statement or, should the Commission decide that clarification is not the appropriate remedy, reverse this finding on rehearing. The Canadian Government also requested that the FERC clarify its statement to avoid creating uncertainty with respect to the U.S. commitments to its treaty with Canada and the ANGTS. On August 31, 1999, the FERC expeditiously issued a clarification to its earlier order. Among other things, the Commission stated that its intent was to indicate the immediate conditions surrounding Northern Border's cost-of-service tariff and that in no way did it intend to indicate that the ANGTS project would not be fully implemented. This clarification is the latest in a long history of inter-governmental cooperation and support for the ANGTS.

IX. THE DEMPSTER LATERAL PROJECT

In its 1977 Reasons for Decision selecting the Foothills alternative for transportation of Alaskan gas, the NEB recommended to the Governor-In-Council that Foothills be required to execute an agreement to provide for a Dempster Lateral to interconnect with the ANGTS in order to accommodate the transportation of Northern Canadian gas when required. In this respect, the Canada/U.S. Agreement not only provides for the Dempster Lateral, but stipulates that a significant portion of the costs of the Dempster Project can be rolled-in to the ANGTS.

On May 4, 1978, Foothills, its subsidiaries, and its parent companies entered into two agreements with the Government of Canada. The Dempster Link Agreement requires Foothills to cause the construction of the Dempster Lateral as expeditiously as possible following leave to open Phase II of the Canadian segment of the ANGTS, subject to the issuance of a certificate of public convenience and necessity and a determination that financing can be achieved without undue financial burden. Foothills has fulfilled its obligations to date under this agreement, including the filing of an application with the NEB for a certificate to construct the Dempster Lateral. The Natural Gas Throughput Agreement requires Foothills and its subsidiaries to provide, upon notice from the Minister of Energy, Mines and Resources, sufficient throughput capacity in the ANGTS to accommodate volumes of Northern Canadian gas.

X. THE MACKENZIE VALLEY PIPELINE PROJECT

In late 1988, three major producers in the Mackenzie Delta filed applications with the NEB for licences to export 9.2 TCF of Canadian frontier gas to the United States over 20 years commencing as early as 1996. These applications raised the possibility that Mackenzie Delta natural gas reserves could be marketed in advance of Alaskan reserves in the U.S. lower 48 states.

As part of Foothills' ongoing commitment to transport both Alaskan and Canadian Mackenzie Delta gas reserves to market, in October 1989 an application was filed with the NEB for a pipeline from the Mackenzie Delta along the Mackenzie River and then south to connect with an extended Prebuild at Boundary Lake, British Columbia. The Mackenzie Valley Pipeline is an alternative to the Dempster Lateral.

The application remains before the NEB. In the interim, Foothills, the Delta producers and two other pipeline companies signed an agreement to form a joint venture for the further development of the Mackenzie Valley Transportation System. The joint venture agreement terminated in 1998.

XI. OTHER DEVELOPMENTS

ALASKA NORTH SLOPE PROJECT

In 1998, Foothills became a participant in a joint venture with four other sponsors to examine the viability of a project for the delivery of liquefied natural gas from reserves on the North Slope of Alaska to markets in East Asia. The project contemplates that natural gas would be shipped by pipeline across Alaska to the southern coast, liquefied and delivered by tankers. Foothills believes this initiative is wholly consistent with the transportation of gas via the ANGTS and may provide synergies for both projects, thus further reducing the cost of transportation.

XIII. LIST OF FOOTNOTES

In the following notes, "S.C." refers to the Statutes of Canada; "U.S.C." refers to the United States Code; "U.S.T." refers to the United States Treaties; "T.I.A.S." refers to U.S. Treaties and Other International Acts Series; "F.E.R.C." refers to the Federal Energy Regulatory Commission Reporter (Commerce Clearing House, Inc.); "F.2d" refers to the U.S. Federal Reporter, Second Series (West Publishing Co.); and "E.R.A." refers to the Federal Energy Guidelines, Energy Management (Commerce Clearing House, Inc.).

[1] 15 U.S.C. 719, et seq.

[2] At the time of the Recommendation, the FPC was constituted of only four members; the fifth position was vacant.

[3] Reasons for Decision, Northern Pipelines, Vol. I. pp. 161-162, issued by National Energy Board on July 4, 1977.

[4] 29 U.S.T. 3581, T.I.A.S. No. 9030. The Agreement on Principles is set forth in full on pp. 47-83 of the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, issued September 20, 1977; it is also set forth in the Canadian Northern Pipeline Act, Bill C-25, passed April 4, 1978, Third Session, Thirtieth Parliament, 26-27, Elizabeth II, 1977-78.

[5] President's Decision, p. xii.

[6] Id. at 93.

[7] Senate Joint Resolution 82, 95th Congress, 1st Session (1977).

[8] Alcan Pipeline Company, et al., 1 F.E.R.C. Para. 61,248 (December 16, 1977).

[9] Alaskan Northwest Natural Gas Transportation Company, 3, F.E.R.C. Para. 61,290 (June 30, 1978).

[10] Bill C-25, passed April 4, 1978, Third Session, Thirtieth Parliament. S.C. 1977-78, C. 20.

[11] Metzenbaum v. F.E.R.C., 675 F.2d 1282 (D.C. Cir. 1982).

[12] Northwest Alaskan Pipeline Company, et al., 10 F.E.R.C. Para. 61,032 (January 11, 1980).

[13] Id. at pp. 61,079-80.

[14] Ibid.

[15] Northwest Alaskan Pipeline Company, et al., 11 F.E.R.C. Para. 61,088 (April 28, 1980).

[16] Id. a p. 61,138.

[17] The April 28 order stated: "The Commission can accept that the Canadian producers have a legitimate requirement for an assured cash flow. By way of analogy to the role of the ship-or-pay obligation between the shipper and the transporter [Foothills] in obtaining financing for the transportation system, the Canadian producer needs to establish what amounts to an accounts receivable from U.S. importers at an assured minimum value. Like the transporter [Foothills], the producer needs from his customers an unconditional obligation to pay sufficient to enable him to attract financing." 11 F.E.R.C. at p. 61,162 (emphasis added).

[18] To determine the amount of revenue which Northwest Alaskan and the U.S. purchasers would be required to generate annually and daily, the FERC established a formula under which a base price of $3.45 per MMbtu (the uniform border price which was in effect when the record in the prebuild import proceeding was closed) would be multiplied times the quantities of gas specified in the prebuild contracts. For example, using an unescalated base price of $3.45, Northwest Alaskan's obligation under the Eastern Leg contract would be limited to $1,380,000 daily (800,000 Mcf/d x 3.45/MMbtu x 50%) and $856,290,000 annually (800,000 Mcf/d x 365 days x $3.45/MMbtu x 85%). In its June 20, 1980 order on rehearing, the FERC modified this formula so as to

permit the base price of $3.45 to be adjusted monthly for inflation by using the escalator mechanism contained in Section 101(a) of the Natural Gas Policy Act. 11 F.E.R.C. Para. 61,302, pp. 61,606-607.

[19] 11 F.E.R.C. Para. 61,088, pp. 61,162-163.

[20] Id. at p. 61,163.

[21] 11 F.E.R.C. Para. 61,088, p. 61,165.

[22] Condition 12 of the ANGTS construction certificate granted to Foothills by the Northern Pipeline Act originally provided that, "before the commencement of construction," Foothills shall establish to the satisfaction of the Minister responsible for the Northern Pipeline Agency and the NEB that "financing has been obtained for the pipeline." In order to permit construction of the prebuild phase, however, the Canadian government subsequently amended Condition 12 to require that Foothills, prior to the commencement of construction, establish to the satisfaction of the Minister and the NEB that, among other things, financing has been obtained for the prebuilt sections and can be obtained for the completion of the remainder of the system.

[23] See NEB's statement of May 9, 1980, in a proceeding entitled "In the Matter of the National Energy Board Act and the Northern Pipeline Act; and In the Matter of a Public Hearing with Respect to Condition 12(1) of Schedule III of the Northern Pipeline Act; File No. 1045-4."

[24] Id. at p. 8.

[25] Petition of Foothills Pipe Lines (Yukon) Ltd. and Pan-Alberta Gas Ltd. for Rehearing, filed May 28, 1980, in Northwest Alaskan Pipeline Company, et al., FERC Docket Nos. CP78-123, et al. (p. 13).

[26] Northwest Alaskan Pipeline Company, et al., 11 F.E.R.C. Para. 61,302 (June 20, 1980), p. 61,607.

[27] Id. at p. 61,605.

[28] Ibid.

[29] See note 26, supra.

[30] See e.g., DOE/ERA Opinion and Order No. 67, 1 E.R.A. Paragraph 70,579 (December 13, 1984), and Northwest Alaskan Pipeline Company (Eastern Leg), 29 F.E.R.C. Paragraph 61,302 (December 14, 1984).

[31] Order No. 380-A, "Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, "F.E.R.C. Statutes and Regulations Paragraph 30,584 (July 30, 1984), aff'd, Wisconsin Gas Company v. F.E.R.C., 770 F.2d 1144 (D.C. Cir. 1985), cert. denied, 476 U.S. 1114 (1986).

[32] Id. at p. 31,062 (emphasis added, footnotes omitted). The Commission's exemption of the prebuild tariffs was reaffirmed in Order No. 380-B, 29 F.E.R.C. Paragraph 61,076 (October 24, 1984), at p. 61,157, wherein the Commission emphasized, inter alia, that "the exemption is based on the Commission's repeated assurances of a stream of revenues for the construction and operation of the 'pre-built' segments of the ANGTS," and "[t]hose assurances, in turn, reflect the mutual trust and cooperation between the governments of the U.S. and Canada with respect to the ANGTS." (footnote omitted). See also Order No. 380-C, F.E.R.C. Statutes and Regulations Paragraph 30,607 (October 24, 1984), at p. 31,195-96.

[33] Wisconsin Gas Company et al. v. F.E.R.C., 770 F.2d 1114 (D.C. Cir. 1985), cert. denied, 476 U.S. 1144 (1986).

[34] id. at 1163

[35] Natural Gas Pipeline Company of America, Opinion No. 256-A, 39 F.E.R.C. Paragraph 61,218, p. 61,770 (May 27, 1987) (footnote omitted).

[36] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636-A, 57 Fed. Reg. 36,128 (1992), 191-96 FERC Stats. & Regs., Regs. Preambles, ¶ 30, 950, at p. 360,674 (1992);

see also, Northern Border Pipeline Co., 63 FERC ¶ 61,289, at. P. 62,954 (1993); *Northern Natural Gas Co.*, 62 FERC ¶ 61,075, at p. 61,397 (1993).

[37] *Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs; Notice of Proposed Rulemaking*, IV FERC, Proposed Regs. ¶ 32,511, at p. 32,947 (1994).

[38] *Id*, at p. 32,947 (footnote omitted and emphasis added)

[39] *Id*, at pp. 32,947-48.

[40] *Northern Border Pipeline Co.*, 65 FERC ¶ 61,179, at p. 61,892, n.19 (1993).

[41] *Pacific Interstate Transmission Co.*, 85 FERC ¶ 61,378, at p. 62,451 (Dec. 17, 1998) ("The Commission has recognized the unique status of PITCO [which is part of Western Leg Prebuild system] on numerous occasions . . . and the arrangements related to the sale of Canadian gas to SoCal Gas are unique."); *see also, Pacific Interstate Transmission Co.*, 77 FERC ¶ 62,053, at p. 61,196 (1996) ("Approval of the PITCO request will approximately balance two Commission policies – the Commission's longstanding commitment to the ANGTS and the open-access conditions of Order No. 636.")

[42] ANNGTC's FERC Form No. 2, for year ending December 31, 1998, at p. 123.0.

[43] *Northwest Alaskan Pipeline Co.*, 49 FERC ¶ 61,394, at p. 62,453 (1989); *see also, Northern Border Pipeline Co.*, 65 FERC ¶ 61,179, at p. 61892, n. 19 (1993).

Concurrent Resolution Expressing the Sense of Congress Regarding the Importance of the Alaska Natural Gas Transportation System

Whereas, the Alaska Natural Gas Transportation System is a critically important energy project that will tap Alaska's North Slope natural gas reserves which constitute more than ten percent of this nation's entire proven natural gas reserves;

Whereas, the System, when complete, will supply the United States with five percent of its annual natural gas demand, displacing over 400,000 barrels of oil, thereby greatly reducing this nation's excessive dependence on foreign oil;

Whereas, the Congress has already expressed its overwhelming support for the System in approving by joint resolution the President's 1977 Decision on the Alaska Natural Gas Transportation System;

Whereas, a portion of the System known as prebuild can be constructed by the end of 1981 to bring Canadian gas to this nation until the entire system is complete in 1985;

Whereas, prebuild will contribute to completion of the entire system by spreading demand for capital, labor and materials over several years, and will enable this nation to obtain Canadian natural gas to displace 200,000 barrels of foreign oil a day;

Whereas, the Federal Energy Regulatory Commission has issued decisions granting certificates for the prebuild facilities in the United States;

Whereas, the Sponsors of the Alaskan segment of the system and the North Slope natural gas producers have entered into an agreement to fund and manage jointly the design, engineering and cost estimation for the Alaskan segment and have made a joint Statement of Intention to work to develop a financing plan for the Alaskan segment with the object of completing construction by the end of 1985; Now, therefore, be it

• Resolved by the Senate (the House of Representatives concurring) that it is the sense of Congress that the System remains an essential part of securing this nation's energy future and, as such, enjoys the highest level of Congressional support for its expeditious construction and completion by the end of 1985.

July 17, 1980

Dear Mr. Prime Minister:

Since you last wrote to me in March, the United States Government has taken a number of major steps to ensure that the Alaska Natural Gas Transporation System is completed expeditiously.

Most significantly, the Department of Energy has acted to expedite the Alaskan project. The North Slope producers and Alaskan segment sponsors have signed a joint statement of intention on financing and a cooperative agreement to manage and fund continued design and engineering of the pipeline and conditioning plant. The Federal Energy Regulatory Commission recently has certified the eastern and western legs of the system.

The United States also stands ready to take appropriate additional steps necessary for completion of the ANGTS. For example, I recognize the reasonable concern of Canadian project sponsors that they be assured recovery of their investment in a timely manner if, once project construction is commenced, they proceed in good faith with completion of the Canadian portions of the project and the Alaskan segment is delayed. In this respect, they have asked that they be given confidence that they will be able to recover their cost from U.S. shippers once Canadian regulatory certification that the entire pipeline in Canada is prepared to commence service is secured. I accept the view of your Government that such assurances are materially important to insure the financing of the Canadian portion of the system.

The Right Honorable
Pierre Elliott Trudeau, P.C., Q.C., M.P.,
LL.L., M.A., F.R.S.C.,
Prime Minister of Canada,
Ottawa

Existing U.S. law and regulatory practices may cast doubt on this matter. For this reason, and because I remain steadfastly of the view that the expeditious construction of the project remains in the mutual interests of both our countries, I would be prepared at the appropriate time to initiate action before the U.S. Congress to remove any impediment as may exist under present law to providing that desired confidence for the Canadian portion of the line.

Our Government also appreciates the timely way in which you and Canada have taken steps to advance your side of this vital energy project. In view of this progress, I can assure you that the U.S. Government not only remains committed to the project; I am able to state with confidence that the U.S. Government now is satisfied that the entire Alaska Natural Gas Transportation System will be completed. The United States' energy requirements and the current unacceptable level of dependence on oil imports require that the project be completed without delay. Accordingly, I will take appropriate action directed at meeting the objective of completing the project by the end of 1985. I trust these recent actions on our part provide your government with the assurances you need from us to enable you to complete the procedures in Canada that are required before commencement of construction on the prebuild sections of the pipeline.

In this time of growing uncertainty over energy supplies, the U.S. must tap its substantial Alaskan gas reserves as soon as possible. The XXVI trillion cubic feet of natural gas in Prudhoe Bay represents more than ten percent of the United States' total proven reserves of natural gas. Our governments agreed in 1977 that the Alaska Natural Gas Transportation System was the most environmentally sound and mutually beneficial means for moving this resource to market. Access to gas from the Arctic regions of both countries is even more critical today as a means of reducing the dependence on imported petroleum.

Successful completion of this project will underscore once again the special character of cooperation on a broad range of issues that highlights the U.S./Canadian relationship.

I look forward to continuing to work with you to make this vital energy system a reality.

Sincerely,

(Signed: Jimmy Carter)

N.B.: A signed copy of this statement is held in NES File No. 1045-4

NATIONAL ENERGY BOARD
OTTAWA, K1A 0E5

OFFICE NATIONAL DE L'ÉNERGIE
OTTAWA, K1A 0E5

File No.: 782-13
25 June, 1984

The Secretary,
Federal Energy Regulatory Commission,
825 North Capitol Street, N.E.,
Washington, D.C. 20426

Dear Sir:

Subject: Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions
Order No. 380 - Docket No. RM 83-71-000

The National Energy Board has examined from a Canadian public interest point of view, within the regulatory framework, the direct and particularly the indirect effects of Order No. 380 on Canadian exports of natural gas, on Canadian pipelines, and on Canadian producers. It has carried out a survey of the views of Canadian exporters. On the basis of both its own assessment and the information drawn from the survey, the National Energy Board has grave concerns about the effects on Canada of Order No. 380. The views of Alberta & Southern, Pan-Alberta, TransCanada PipeLines and Mobil Oil Canada Ltd., are attached as examples of the major concerns expressed in the survey.

The Board understands that the latest date for filing submissions for clarification or modification of the Order is 25 June 1984. The Board further understands that the order, in its original form or modified, may then come into effect as early as 31 July 1984. Accordingly, the Board is taking the unusual step of making its views known directly by this submission to the Commission. Additionally, Canadian pipelines and producers may not be entirely aware of all of the implications of Order No. 380. In fact, the Order acts on tariffs between U.S. pipeline companies and their buyers, and the indirect effects were only peripherally reviewed in it. Commissioner Sousa himself states, "It is unclear to me the extent of the impact that this rule may have on imported natural gas, the vast portion of which comes from Canada."

RECEIVED

JUL [illegible] 1984

... 2

PAN-ALBERTA GAS LTD.

It should be pointed out at this juncture that the NEB is not questioning the underlying objective of Order No. 380, namely that natural gas become competitively priced in United States markets. On the contrary, it emphasizes that it believes the concerns of Canada can be accommodated without affecting this objective. It believes that the alleviation of Canadian concerns will ensure the ability of Canada to be a reliable supplier of natural gas to the United States for many years into the future.

The Board believes the Commission would wish to examine the implications of the issues in this submission before implementing the Order with respect to Canadian imports.

The four concerns of the NEB are outlined below:

1. Uncertainties arising from the Order

There are numerous uncertainties relating to the interpretation and application of the order. We understand that they will be addressed in various submissions for clarification and modification to be made to the Commission. They are not, therefore, identified in this submission. In addition, it is unclear to this Board to what extent producer fixed costs are exempted from the effect of the Order.

The NEB recognizes the Commission will wish to address these uncertainties before the Order takes effect.

2. Similar Treatment of Canadian fixed costs (Pipelines and Producers) to those accorded to the United States fixed costs.

The FERC Order requires that in the tariffs of United States pipelines, fixed costs should be separated from variable costs and purchased gas costs. The non-incurred variable costs, i.e., for gas not taken, are then excluded from minimum bills. The Order is silent on such costs in Canada. The NEB requests similar treatment for these costs in Canada since the pipeline system from supplier to market is, for all intents and purposes, one continuous transmission system.

Likewise, Canada would request similar treatment to the extent that the fixed costs of U.S. producers are identified and included in minimum bills. (Producer fixed costs related to ANGTS prebuild facilities are a special case dealt with in Section 3 below.)

... 3

The present export price of Canadian natural gas at the international boundary does not separate pipeline and producer fixed costs from variable costs of the pipeline and those for purchased natural gas. The Board would be pleased to make available to the Commission information on what the Board considers these fixed costs to be.

3. <u>Special Considerations Required for Gas Transmitted on ANGTS Prebuild Facilities</u>

Phase I of the Alaska Highway Natural Gas Pipeline to carry Alberta gas to United States markets pending the arrival of Alaska gas - or, as it is usually referred to, the pre-built section of the pipeline - was constructed under the framework of the Canada-United States Agreement on Principles Applicable to a Northern Natural Gas Pipeline. The Canadian Government approved changes in the terms and conditions of the Northern Pipeline Act made by the National Energy Board. These changes were necessary to enable construction to proceed. They were made on the basis of certain assurances by President Carter about the completion of the pipeline to Alaska as well as resolutions by Congress, and after the National Energy Board and the responsible Canadian Minister were satisfied that the pre-built sections could be financed. Essential to these private financing arrangements was the approval by the FERC in 1980 of a minimum bill to protect both the Canadian pipeline and producer investments and the related contractual arrangements among the participating pipeline companies.

The FERC will therefore understand the concern of the Board about the effect of Order 380 upon these financial arrangements.

Although Order 380 does not apply directly to the contracts between the Canadian seller of Canadian gas and the initial United States buyer, it can be interpreted as applying to cost of service contracts between the initial United States buyer and its customers; these cost of service contracts were an integral part of the structure upon which the financing of the pre-built sections was based. The Order, by reducing the cash flow from buyers to pipeline companies, would weaken the ability of the pipeline companies to pay their minimum bills. Furthermore, since the buyers may have access to lower priced gas, Pan-Alberta could be cut off as a supplier of the gas, and the Canadian producer investments protected by the minimum bill would be impaired. If that interpretation is sustained, Order 380 could constitute a breach of the U.S. Government commitments upon which the National Energy Board and the Canadian Government relied in 1980.

... 4

The Board expresses the view that there are special circumstances surrounding the pre-built sections of the ANGTS which would justify FERC's reconsidering the provisions of Order 380 and seeking means to avoid serious and unwarranted damage to a project undertaken in good faith in the interests of both Canada and the United States.

The Board also draws attention to the fact that tariffs on the pre-built sections of the ANGTS are abnormally high. They are high for two reasons: first, because Canada was required to size the pipeline for very large volumes of Alaska gas expected to flow in this decade, rather than for more limited quantities of Canadian gas licensed for export and, second, because depreciation rates are high to enable the costs to be amortized over the short term of export and import licenses.

In the circumstances, it appears to the Board to be unfair and unreasonable if Canadian producers were to have to absorb the full burden of these extra costs.

4. The Removal of Take or Pay Protection

In its present form, the FERC Order does not appear to address the following two fundamental issues.

First, the Order points out that if the cash flow from the buyers is removed from the subsequent chain of contracts to the suppliers, then the carrying costs of funds required to be borrowed to pay commitments to producers and importers will be allowable for rate-making purposes. The Order does not, however, address the issue of whether the pipeline could then in fact finance the obligations to its suppliers. The results of our survey indicated doubts on this point. We believe the Commission would wish to address this issue.

Second, the Commission does not address the fact that there could be merit in take-or-pay clauses in circumstances where the gas is competitively priced. We would ask the Commission to examine the ability of pipeline companies to finance the construction of pipelines to transmit the gas to market if there are no underpinning throughput arrangements similar to those contained in take-or-pay clauses. We believe this may be particularly true for large new pipelines and is referred to on page 18 of the DOE New Policy Guidelines. We would ask the Commission to consider this point in relation to the capability of sustaining the supply of gas to the U.S. markets over the long term. Is there any reason to interfere with freely negotiated take-or-pay clauses in circumstances where the natural gas is competitively priced in the marketplace?

... 5

In regard to submissions that the Commission will be receiving, the Board would point out that export/import contracts underpin the NEB licences and cannot be changed without NEB approval if the licence is to remain valid. The NEB has been flexible in relaxing take-or-pay conditions in the present abnormal market conditions. Long-term contracts have for decades underpinned the financing of pipeline and producer investments. Any abrogation of a contract which forms part of the series of interlocking contracts, including the export/import contract, could have serious consequences.

In summary, competitively priced Canadian gas and a regulatory system which fosters high load factor operation of pipelines appear to be the twin pillars on which the long range mutually beneficial gas trade between our two countries can prosper.

The National Energy Board wishes this submission to form part of the public record in the FERC proceedings in the rehearing of matters related to Order No. 380.

Yours sincerely,

G. Yorke Slader

G. Yorke Slader,
Secretary

Department of Energy
Washington, D.C. 20585

July 13, 1984

Honorable Raymond J. O'Connor
Chairman
Federal Energy Regulatory Commission
825 North Capitol Street, N. E.
Washington, D. C. 20426

Dear Mr. Chairman:

I am writing concerning Order No. 380 now pending before the Commission that appears to have ramifications for the natural gas trade framework we are working to establish. I write with an appreciation for the care and understanding that the Commission has given to this important ruling.

Although the ruling addresses the variable costs in minimum bill obligations between gas purchasers and pipeline suppliers, its possible effects on upstream contracts were recognized by the Commission. The potential impact on international gas contracts, particularly between U. S. buyers and Canadian sellers, has been the subject of comments submitted to the Commission by these parties. In addition, the Canadian National Energy Board has taken the unusual step of formally communicating its views to the Commission. Most of these comments reflect serious concern over the impact of Order 380 on existing import arrangements.

It is not my purpose to endorse these comments or to propose any particular course of action for the Commission. The comments speak well for themselves, and the Commission properly has the responsibility to weigh their merits along with other considerations on this issue. My purpose is to share information that may assist the Commission in evaluating the comments and that will ensure that this ruling supports our policy initiatives relating to natural gas trade.

From our perspective, the objectives of Order 380 appear consistent with the gas imports policy guidelines issued by the Secretary of Energy last February. These guidelines were established to promote and construct a gas trade framework in which natural gas imported into the United States is competitive in the markets served. Order 380 promotes competition and is a clear and positive step in support of a deregulated gas marketplace.

In issuing the policy guidelines, the Secretary recognized that gas import arrangements reflect the laws and regulations of the exporter's government as well as our own. The policy statement set forth the criteria to be employed by our regulatory authorities in authorizing future gas imports, and urged parties to current gas import contracts to voluntarily renegotiate their arrangements if necessary to bring them into conformity with the new policy. Implicit in the policy is the requirement that gas imported into the United States must be competitively priced.

As a result of the new policy, reinforced by the weakening of the markets for imported gas, Canadian and U. S. commercial parties have been actively renegotiating their gas purchase arrangements. The Economic Regulatory Administration received reports from U. S. importers on this activity in mid-April that indicated progress in achieving more competitive arrangements. Simultaneously, the Canadian federal government, in coordination with the gas producing provinces, undertook a comprehensive review of Canadian export pricing policy.

The price of Canadian gas has been government administered and has been significantly above the U. S. market-clearing levels. The inflexibility of this price has restricted the ability of our importers to renegotiate fully competitive arrangements with Canadian exporters. We were thus pleased with today's announcement by Canada's new energy minister of the change to market-oriented pricing for Canadian gas exports. This significant action frees U. S. buyers and Canadian sellers to begin renegotiating pricing components of their contracts, if necessary, to make their arrangements market competitive. This announcement has come in time that should be ample for the commercial parties to review their contracts before the beginning of the next contract year this fall.

Canadian authorities believe that Order 380, as issued, could adversely affect the orderly transition to the market-competitive gas trade framework being established. In view of the just announced action by Canada on gas export pricing, we believe this concern merits consideration. Our position is that Canadian gas must compete in the U. S. marketplace on an equal basis with domestic supplies, and that the transition should occur as soon as possible but in an orderly manner.

In addition to the possible effect of Order 380 on the transition to competitive gas import arrangements, there is special concern in Canada over the consequences of this ruling on the pre-built portions of the Alaska Natural Gas Transportation System (ANGTS).

The reasons for this concern have been expressed by the National Energy Board and the commercial parties involved in the ANGTS pre-build in communications to the Commission. We believe these concerns also merit consideration. As currently financed and utilized, the ANGTS pre-build poses challenging problems for both of our agencies as we work to further competition in the gas industry. We should ensure that our respective regulatory processes allow the commercial parties to find solutions for making this system more competitive.

I trust this information will be useful to the Commission in its deliberations. As stated before, it is not my purpose to propose any specific course of action for the Commission. It is appropriate, however, to share with you our perspective on the trade facet of this important ruling.

This letter reflects the views of the Department of State, as well as the Department of Energy.

Sincerely,

RAYBURN HANZLIK
Administrator
Economic Regulatory Administration

cc: Honorable Georgiana Sheldon
Honorable A. G. Sousa
Honorable Oliver G. Richard III
Honorable Charles Stalon

UNDER SECRETARY OF STATE
FOR ECONOMIC AFFAIRS
WASHINGTON

Dear Mr. Chairman:

I am writing to bring to your attention several Canadian expressions of concern received at the Department of State about the impact FERC Order 380 relating to minimum commodity bills could have on the export of Canadian gas to the United States.

We have been discussing with the Canadians for over a year in our bilateral Energy Consultative Mechanism (ECM) how to return our bilateral gas trade to a market-sensitive basis. At the last full meeting of the ECM we made good progress and our two Governments issued a joint statement which included the following paragraph:

> "The two sides reaffirmed the importance of a stable long-term natural gas relationship. They emphasized such a relationship provides the United States with security of supply and provides Canada with security of demand for the export of gas surplus to its foreseeable domestic requirements. They recognized that in the long run Canadian gas would have to be competitive in U.S. markets, taking into consideration the security provided by the long-term reserve-based nature of Canadian gas export contracts. They further acknowledged, however, that meeting the objective of competitive conditions may require flexibility and adjustments in response to changes occurring in U.S. gas markets. To this end, the two Governments recognized the importance of holding on-going consultations on the natural gas marketing issue and agreed to meet regularly to discuss common objectives, respective natural gas policies and policy developments."

The Honorable
Raymond O'Connor,
Chairman,
Federal Energy Regulatory Commission,
825 North Capitol Street, NE,
Washington, D.C.

As reflected in this joint statement, the goal of our discussions with the Canadians is the same as what we understand to be the goal of FERC Order 380, namely enhancing competition in the market place.

On June 22, Mr. Geoffrey Edge, Chairman of the Canadian National Energy Board, along with members of the Canadian Embassy, briefed Department of State officials on the adverse impact they fear Order 380 could have on Canadian gas exports. When Ambassador Gotlieb came to see me on June 29, he said the Canadian Government had been surprised by Order 380. He outlined Canadian concerns and left the attached letter. On July 3, at the request of the Canadian Government pursuant to Section 8 of the Agreement between Canada and the United States of America on principles applicable to a Northern Natural Gas Pipeline, Mr. Edge and Mitchell Sharp, Commissioner of the Northern Border Pipeline Agency, met with representatives of the Department of Energy and the Department of State to explain further their view that implementation of Order 380 in its present form could have potential adverse effects on our present and future bilateral gas trade.

I understand that the Canadians have also written FERC on this subject. I will not attempt to cover all the Canadian concerns, but during their meetings with us, the Canadians emphasized first the progress they believe they have made toward a market-sensitive gas export policy. Second, citing the 1980 FERC Prebuild orders, the Canadians made it clear they believe that if FERC Order 380 is put into effect in its present form, we will not be living up to what they regard as our commitments regarding the financing, construction, and operation of the Prebuild section of the Alaskan Natural Gas Transportation System (ANGTS). The Canadians emphasized in this regard the importance of special problems for the Prebuild, a project that has been supported by the U.S. Government based on private financing. (See letter of President Carter to Prime Minister Trudeau of July 17, 1980 and the waiver package submitted by President Reagan to Congress in October, 1981 and approved on December 15, 1981.) Finally, they said that, although they accept the objective of increased market competition inherent in FERC Order 380, they need time to renegotiate gas export contracts in order to put them on a more market-sensitive basis.

As a further step, just today, the new Canadian Government has announced what we consider a significant new gas export pricing policy based on negotiated prices between buyers and sellers reflecting market conditions, and subject to criteria set by the National Energy Board. We expect Canadian experts to brief us the week of July 16 through our bilateral Energy Consultative Mechanism on this new Canadian gas export policy, which will be in effect for the new gas contract year beginning November 1, 1984.

Since the Commission still has before it FERC Order 380, I wanted the record of Canadian concerns expressed to the Department of State to be available, so that you would be aware of them in the context of our foreign relations with Canada. You may include this letter and -- with the concurrence of Canadian authorities -- Ambassador Gotlieb's letter to me in the public record in any proceedings before the FERC.

Sincerely,

Allen Wallis

Allen Wallis

Enclosure:
As stated.

Canadian Embassy   Ambassade du Canada

1746 Massachusetts Ave., N.W.
Washington, D.C. 20036

June 29, 1984

Mr. W. Allen Wallis
Under Secretary for
Economic Affairs
Room 7256
Department of State
2201 C Street
Washington, D.C. 20520

Dear Mr. Wallis,

Our two governments have been consulting closely and constructively for over a year and a half on the future of our bilateral natural gas trade.

In light of this cooperation, the new U.S. gas import policy guidelines announced in February and aimed at ensuring that imports enter the United States on a competitive, market oriented basis were drafted so as to permit the kind of arrangements which are essential to Canada's remaining a reliable supplier. For its part, the Canadian Government affirmed that Canadian gas will be competitive in the long term in the U.S. market. A comprehensive review of Canadian gas export policy was undertaken and is now near completion.

I am writing to bring to your attention a recent development that could complicate further progress in this important endeavor.

On May 25 the Federal Energy Regulatory Commission issued Order 380 relating to minimum commodity bills between U.S. pipelines and their buyers. We recognize that this Order is not directed at imports, but that it seeks to address what the FERC has identified as an unnecessary restraint on competition within the U.S. natural gas industry. We have, may I emphasize, no reason to question this objective.

Close study of the Order and discussion with the Canadian industry have convinced my Government that, if implemented in its present form, the Order could have serious adverse effects on present and future bilateral gas trade.

.../2