1992-99 Energy Efficiency & CO_2 Emissions Trends. We track performance from 1992 because in that year our survey began to request data on "pounds of production", which we use as an output metric. Analysis of our survey results indicates energy efficiency (measured as Btus consumed per pound of product produced) improved an average of 3.3% per year since 1992, or a total of 21.1%. CO_2 efficiency (measured as pounds of CO_2 emitted per pound of product produced) improved an average of 3.8% per year since 1992, or a total of 23.7%. (As before, CO_2 emissions include emissions from purchased electricity.)

1990-99 Energy Efficiency & CO_2 Emissions Trends. The Council also tracks energy efficiency and CO_2 emissions performance from 1990, the base year from which emissions reductions are to be measured under the U.N. Framework Convention on Climate Change. In this analysis we use the dollar value of sales, deflated by the BLS Producer Price Index for Industrial Chemicals, as the output measure. Analysis of our survey results indicates energy efficiency (measured as Btus consumed per 1990$ of sales) improved an average of 1.9% per year since 1990, or a total of 15.8%. CO_2 efficiency (measured as tons of CO_2 emitted per million 1990$ of sales) improved an average 2.2% per year, or a total of 18.4%. (Again, CO_2 emissions include emissions from purchased electricity.)

We think this year's survey results show very real energy and CO_2 emissions efficiency progress. However, we must remember that as much as we hope to see such progress continue, past performance does not guarantee the same performance in the future. Many of our members believe that the "low-hanging fruit" has been picked, and that future energy efficiency and greenhouse gas emissions improvements with current technology will be more difficult and more costly than in the past. In addition, general economic conditions drive apparent energy efficiency performance from year to year; specifically, lower capacity utilization typically degrades energy efficiency performance.

II. Results of the 1999 Energy Efficiency Awards Program. Twenty-three projects carried out by ten Council member companies were honored with 1999 Energy Efficiency Awards. Attachment 2 contains short descriptions of each of the winning projects. These winning activities consisted of a variety of innovative measures which were successful in improving energy efficiency and reducing or avoiding related emissions including CO_2 emissions.

III. American Chemistry Council policy recommendations. The Council will continue vigorous implementation of our Energy Efficiency Continuous Improvement Program and our Climate Action Program. We will continue the industry's long-standing tradition of improving energy efficiency and reducing the carbon intensity of our operations, thus demonstrating the effectiveness of voluntary programs in helping to achieve domestic and international energy policy and global climate change goals. We will also continue to research, develop and provide chemistry products that enable other industries and individual consumers to improve *their* energy efficiency and reduce *their* emissions.

While the business of chemistry will continue its efforts, government also has a vital role to play. The American Chemistry Council strongly supports a national energy policy that restores balance to U.S. energy markets by promoting high environmental protection standards, now and for future generations, and a diverse, flexible energy supply at globally competitive prices. To achieve those goals the Council believes the nation should:

- **Use all available and proven energy sources.** Over 75 percent of the nation's electricity output comes from oil, coal and nuclear power. The nation cannot turn its back on these and other supply enhancing energy sources. The nation must fully use advanced oil, coal and nuclear technologies and invest in non-traditional and renewable energy sources.
- **Balance natural gas markets.** Natural gas is fast becoming the nation's fuel of choice. It is in high demand to heat homes, fuel factories, and create electricity. Today, there is simply not enough natural gas to go around. New supplies must be responsibly developed, and new measures are needed to ease demand growth.
- **Remove unintended regulatory barriers to safe and reliable energy.** Some government policies have severely restricted the production and distribution of energy, especially electricity supplied from cogeneration technology.
- **Improve energy distribution channels.** Our energy distribution infrastructure is inadequate. New natural gas pipelines are needed and we must pursue a continental natural gas supply and power movement strategy.

The Council believes that U.S. government policy to address the issue of global climate change should focus on the following elements:

- Encouragement of voluntary actions to improve energy efficiency and reduce or avoid greenhouse gas emissions, and appropriate recognition of these actions;
- Targeted research to resolve uncertainties in the science of global climate change;
- Removal of barriers to the deployment of energy efficient and greenhouse-friendly technologies; and,
- Research and development of breakthrough new technologies to dramatically reduce the greenhouse impact of energy-related and other anthropogenic emissions.

I recently wrote you to explain the important benefits that cogeneration brings to the business of chemistry and the nation. I emphasized our concern about possible amendments to the Public Utility Regulatory Policies Act (PURPA) which would remove that statute's vital protections of cogeneration facilities against monopoly abuses, and thus jeopardize our industry's cogeneration contribution to the nation's electricity supply. Let me reiterate our concern at this time.

I hope you find the above information to be of interest. I would welcome the opportunity to meet and discuss it with you. If you or members of your staff should have questions, please call me or call Thomas Parker, Jr. of the Council's Energy Team, at 703-741-5916.

Sincerely,

Fred

Frederick L. Webber
President & CEO

attachments:

1. "American Chemistry Council *1999 Energy Efficiency and Greenhouse Gas Emissions Survey – Summary of Data, 1990-1999*", April 17, 2001
2. "*American Chemistry Council 1999 Energy Efficiency Awards Program: Award Winners, with Summary Descriptions*", November 13, 2000

cc: The Hon. Joe Kelliher, Senior Advisor to the Secretary, Department of Energy
The Hon. Robert Kuripowickz, Acting Assistant Secretary, Fossil Energy, Department of Energy
The Hon. Abraham Haspel, Acting Assistant Secretary, Energy Efficiency and Renewable Energy, Department of Energy
The Hon. Colin L. Powell, Secretary of State
The Hon. Paula Dobriansky, Under Secretary-designate for Global Affairs, Department of State
The Hon. Alan P. Larson, Under Secretary for Economic, Business and Agricultural Affairs, Department of State
The Hon. Kenneth Brill, Acting Assistant Secretary for Oceans and International Environmental and Scientific Affairs, Department of State
The Hon. Paul H. O'Neill, Secretary of the Treasury
The Hon. Mark Sobel, Acting Assistant Secretary for International Affairs, Department of the Treasury
The Hon.Donald L. Evans, Secretary of Commerce
The Hon. Robert C. Reiley, Director, Office of Metals, Materials and Chemicals, , Department of Commerce
The Hon. Christie Whitman, Administrator, Environmental Protection Agency
The Hon. Jeffrey Holmstead, Assistant Administrator-designate for Air and Radiation
The Hon. Andrew Lundquist, Executive Director of the National Energy Policy Development Group, the White House
The Hon. Karen Knutson, Deputy Director of the National Energy Policy Development Group, the White House

Attachment 1

American Chemistry Council 1999 Energy Efficiency and Greenhouse Gas Emissions Survey
Summary of Data, 1990-1999

Number of Companies Reporting, 1999: 72

Total Sales, 1999: 129.33 (1999 $)
123.125 (constant 1990 $)

I. 1999: Non-Feedstock Energy Consumption

		Total Energy (million Btu)	Share in Energy Consumption, % Purchased	Total	Total CO_2 Emissions* (tons)	Share in Total CO_2 Emissions*
Purchased Fuel & Electricity						
Natural Gas	(975,601,368 MCF)	1,004,814,093	53%	40%	58,239,332	37%
Electricity	(59,346 million kWh)	589,325,883	31%	23%	39,514,300	25%
Coal	(8,140,955 tons)	149,557,232	8%	6%	15,782,372	10%
Steam	(119,202 million lbs)	145,632,795	8%	6%	9,521,201	6%
All Other	n/a	21,747,384	1%	1%	1,129,385	1%
Sub-total, purchased:		1,911,077,387	100%	76%	124,186,590	79%
Fuel Produced On-Site		600,659,803		24%	33,933,229	21%
Total, Purch. & On-Site		2,511,737,190		100%	158,119,819	100%

Averages	In 1999 Dollars	In 1990 Dollars	
Total Energy Consumption	19,421	20,400	Btu/$ of sales
Total CO_2 Emissions*	1,223	1,284	tons/MM$ of sales

*CO_2 emissions from purchased electricity are imputed from electric utilities' emissions

Alternative calculations for CO_2 emissions including emissions from purchased *feedstock* electricity

Purchased *feedstock* electricity CO_2 emissions, tons:	9,490,291
Total CO_2 Emissions, tons:	167,610,110

II. 1999: Feedstock Energy Consumption

Feedstock Type	Physical Units		Total Energy Million Btus	Quads Equivalent	Share of Feedstocks
Ethylene	15,223	million lbs	330,338,760	0.330	15%
Propylene	14,091	million lbs	295,902,825	0.296	14%
Natural Gas	274,527,643	MCF	282,763,472	0.283	13%
Propane	2,493,768,332	gallons	229,426,687	0.229	11%
Ethane	2,799,439,428	gallons	195,400,872	0.195	9%
Xylene	1,282,507,766	gallons	174,677,558	0.175	8%
Napthas and Raffinates	32,207,103	bbl	161,035,515	0.161	7%
All Other	n/a		507,355,519	0.507	23%
Total Feedstocks			2,176,901,208	2.177	100%

Note well that all emissions data presented in this report are as short tons of carbon dioxide. In other contexts emissions are reported as short tons of carbon or carbon equivalent, or as metric tons of carbon or carbon equivalent. To convert short tons of carbon dioxide to short tons of carbon or carbon equivalent, multiply the short tons of carbon dioxide by 12/44 (or 0.2727). To convert short tons to metric tons, multiply short tons by 0.9072. The combined multiplier to convert short tons of carbon dioxide to metric tons of carbon or carbon equivalent is 0.2474.

American Chemistry Council 1999 Energy Efficiency and Greenhouse Gas Emissions Survey
Summary of Data, 1990-1999

III. 1999: Total Emissions of Greenhouse Gases

	Tons CO_2 or CO_2 Equivalent	Percent
CO_2 emissions from non-feedstock energy, purchased plus on-site, including purchased electricity	158,119,819	70.2%
CO_2 emissions from purchased feedstock electricity	9,490,291	4.2%
Emissions of greenhouse gases other than CO_2 produced from combustion of fuels*, expressed as CO_2 equivalent	57,733,016	25.6%
Total greenhouse gas emissions, CO_2 and CO_2 equivalent	225,343,127	100.0%

* These greenhouse gases are *process* CO_2, nitrous oxide (N_2O), methane (CH_4), HFCs, PFCs and SF_6

III. 1998-99: Comparison of 48 Companies Reporting Dollars of Sales and Pounds of Production in Both Years

	1998	1999	Units	Change, %
Sales (constant 1990$)	98.7	103.9	billion $	5.3%
Pounds of Production	429,015	441,955	million lbs	3.0%
Energy				
Purchased & On-Site Energy	1.984	2.019	quads	1.7%
Ratio to Pounds	4,625	4,568	Btu/lb	-1.2%
CO_2 Emissions, Including Purch. Electricity*				
Purchased & On-Site Energy CO_2	134.040	136.179	million tons	1.6%
Ratio to Pounds	0.6249	0.6162	lbsCO_2/lb	-1.4%
Total GHG Emissions**, as CO_2 Equivalent				
As CO_2 Equivalent	170.4	174.9	million tons	2.7%
Ratio to Pounds	0.794	0.792	LbCO2/LbPrd	-0.3%

* Non-feedstock & feedstock electricity

**These greenhouse gases are *combustion* and *process* CO_2, nitrous oxide (N_2O), methane (CH_4), HFCs, PFCs and SF_6

IV. 1990-99: Cumulative Energy Efficiency and CO_2 Emissions Trends Based on Successive Groups of Two-year Repeat Reporting Companies

	% Change Since Base Year	
	Total	Average
Energy* efficiency (intensity) trend - Btu/1990$ - 1990 base year	-15.8%	-1.9%
Energy* efficiency (intensity) trend - Btu/Lb - 1992 base year	-21.1%	-3.3%
CO_2** efficiency (intensity) trend - tons/ MM 1990$ - 1990 base year	-18.4%	-2.2%
CO_2** efficiency (intensity) trend - LbCO2/LbProd - 1992 base year	-23.7%	-3.8%

* Energy consists of non-feedstock purchased plus on-site energy.

** In calculating CO_2 emissions, emissions from purchased electricity (non-feedstock and feedstock) are included, along with emissions from other non-feedstock purchased plus on site energy inputs. Emissions of other greenhouse gases including "process CO_2" are not included.

Note well that all emissions data presented in this report are as short tons of carbon dioxide. In other contexts emissions are reported as short tons of carbon or carbon equivalent, or as metric tons of carbon or carbon equivalent. To convert short tons of carbon dioxide to short tons of carbon or carbon equivalent; multiply the short tons of carbon dioxide by 12/44 (or 0.2727). To convert short tons to metric tons, multiply short tons by 0.9072. The combined multiplier to convert short tons of carbon dioxide to metric tons of carbon or carbon equivalent is 0.2474.

Attachment 2

AMERICAN CHEMISTRY COUNCIL
1999 ENERGY EFFICIENCY AWARDS PROGRAM
AWARD WINNERS, WITH SUMMARY DESCRIPTIONS

Number:	1
Company:	**Texas Petrochemicals LP**
Category:	Significant Improvement in Manufacturing - Plant Site
Entity:	Houston, Texas Plant
Title:	TPC Instrumentation Upgrade

Description: To continue its multi-year pursuit of energy reduction, in 1999 Texas Petrochemicals LP implemented a plant instrumentation upgrade project along with several smaller heat recovery projects to increase processing efficiency and to lower overall energy consumption per pound of product. The installation of the instrumentation upgrade utilizing Honeywell distributed controls technology increased production rates. The advanced controls and process modeling then allowed operating the process closer to product specifications, thus decreasing energy usage. Steam heat recovery was increased by replacing a 15 pound steam boiler economizer section with a more efficient 750 pound economizer. In another waste heat recovery boiler installation of steam drum de-misters eliminated sodium carryover and allowed more efficient supplemental firing. Finally, the use of excess condensate flash heat was initiated for preheating two process tower feeds. Actual energy savings realized during 1999 were 508,896 MMBtu. Energy per pound of product decreased 3.3% and CO_2 emissions per pound decreased 5.3%. Larger full year savings were expected for the year 2000.

Number:	2
Company:	**Celanese**
Category:	Environmental Impact - Project
Entity:	Bay City, Texas Plant
Title:	Plant Ethylene Flare Noise and Steam Reduction

Description: Excessive use of 160-psig steam to an ethylene flare caused by a malfunctioning sensor wasted energy and resulted in a pulsating flame and noisy flare. Inadequate steam input, however, would have resulted in excessive smoke, a reportable event to state environmental authorities. Initial observation did not reveal any controller tuning problem. Cause and effect analysis was used to identify and assess factors which might be responsible for the excess steam: a malfunctioning steam flow transmitter, the infrared sensor, and process vent streams not previously accounted for. Further work with instrument maintenance personnel indicated the infrared sensor ('smoke detector') was not programmed properly, giving an incorrect high infrared signal which in turn caused input of excessive steam to reduce that signal. Company personnel worked with the original manufacturer of the device and the sensor was reprogrammed based on a new procedure. The result was to reduce the 160-psig steam usage from 3.6 thousand lb/hr to

0.6 thousand lb/hr, an annualized savings of 39,322 MM Btu of boiler fuel gas, and to mitigate the excessive noise.

Number:	4
Company:	**Celanese**
Category:	Significant Improvement in Manufacturing - Operating Unit
Entity:	Operating Unit Within the Clear Lake, Texas Plant
Title:	Use of Excess Process Steam for Heat Recovery

Description: Process-generated steam contained a small amount of organic process material. This steam could not go directly into the plant steam system with this contaminant, so it was vented, resulting in the annual discharge to the environment of approximately 4,000 pounds of the organic material. In another part of the same process, purchased steam was used to reboil a Flasher vessel. A company engineer conducted HTRI calculations to determine whether the Flasher reboiler could operate properly if the process-generated steam were used and condensed in the reboilers, instead of the purchased steam. When the answer was affirmative, the unit decided to implement a low-cost project. New pipelines and jumpers were designed and installed. The process steam was then lined up to the Flasher reboiler, displacing purchased steam. Annualized energy savings are approximately 65,000 MMBtu, or 1.8% per unit of production. The project also has environmental benefits. The reboiler-generated condensate including the organic material is discharged as effluent, which is then remediated through biological treatment.

Number:	8
Company:	**Celanese**
Category:	Significant Improvement in Manufacturing - Operating Unit
Entity:	Operating Unit Within the Clear Lake, Texas Plant
Title:	Improve Process Control of Large Air Compressor

Description: Company engineers improved the process control for a large air compressor. The new control strategy minimized the differential pressure across the flow control valve downstream of the compressor in order to improve efficiency. In order to open up the flow control valve more, the air discharge pressure of the compressor was reduced by lowering the speed of the compressor. This resulted in saving high pressure steam which powers the compressor. The engineers also trained the operators on how better to operate the equipment. This was an important phase of the project and resulted in a significant change in behavior for the operating unit in managing operation of this compressor. Software changes were made, but no new equipment was required. Annualized energy savings are approximately 22,000 MMBtu, or 1.3% per unit of production.

Number: 9
Company: **Celanese**
Category: Significant Improvement in Manufacturing - Operating Unit
Entity: Pampa, Texas Plant
Title: Furnace Operations Optimization

Description: Several cabin style radiant-wall furnaces are used to crack a vapor feed stream into an intermediate product stream. The furnaces fire natural gas as the primary fuel source and the cracking by-product 'off-gas' as a secondary fuel source. Due to increased production demands, several studies for improving furnace capacity, first pass conversion, and carbon efficiency were conducted. First, burner capacity and heat distribution patterns were evaluated. This revealed that certain burner locations were actually counter-productive to cracking and it was found that fouling in the off-gas burner system caused extensive fluctuation in the heat distribution patterns. In addition, the burner fouling was affecting the pressure controlled off-gas collection system. This caused off-gas to be diverted to the unit flare, which results in an appreciable loss of by-product gas BTUs. Burner capacities and firing patterns were optimized and the secondary fuel burner nozzles were redesigned and re-fabricated to reduce fouling. These activities resulted in an increased furnace capacity (~15%), an increased first pass conversion (~3%) and losses of the off-gas to the unit flare was reduced from ~15% to less than 1%. Lastly, an online condenser wash procedure was implemented to reduce downstream pressure drop. This has helped in maintaining a low process operating pressure within the furnace, which favors cracking conversion. Condenser washes have also helped to extend the process run times by over 10%. The annual energy savings of approximately 7.2% per unit of production has exceeded expectations.

Number: 10
Company: **PPG Industries, Inc.**
Category: Significant Improvement in Manufacturing - Operating Unit
Entity: Lake Charles, Louisiana Plant "C" Chlorine
Title: Tephram® Diaphragms

Description: The "C" Chlorine unit consists of four production circuits, each with 16 bi-polar electrolyzers, each of which in turn contains 12 individual cells, for a total 768 individual cells. Historically these cells used an asbestos diaphragm as the separator between the anode and cathode compartments. Asbestos diaphragms have several shortcomings: problematical long term availability due to environmental concerns; a short life, normally 1 to 1.5 years; and, high operating costs. A company research team created the technology leading to the current "4.2C version" Tephram® Diaphragm more than a decade ago. Several generations of diaphragms were developed and tested before the successful 4.2C version was developed. This diaphragm consists of several non-hazardous, commercially available and proprietary components. Cell renewal crews use equipment essentially identical to that designed for asbestos diaphragms. No modifications to cell structure are required. In addition to using safer materials, the Tephram® diaphragms have demonstrated the following improvements: operating life has more than tripled, to more than four years; product purity has improved; and, substantial energy savings were achieved. Annualized energy savings are approximately 4.4%. The company makes this technology available to others on a license basis.

Number:	11
Company:	**PPG Industries, Inc.**
Category:	Significant Improvement in Manufacturing - Project
Entity:	Lake Charles, Louisiana Plant
Title:	Mercury Cell Voltage Reduction Project

Description: A large amount of power is consumed in the generation of chlorine/caustic soda using mercury cell technology, so even small percentage changes in power consumption can yield significant energy savings. Since this plant operates at a nearly constant load (DC current flow) to meet production demands, any reduction in power consumption must come from a reduction in voltage drop across the mercury cells. The primary method used to change the voltage drop across a cell is to change the distance (or gap) of the movable anodes from a fixed cathode. A project was initiated to use Six Sigma methods to reduce power consumption without any capital investment. All components of voltage drop were identified and the variation of each component was studied. The main sources of variation were anode adjustments, brine feed temperature and ambient temperature. The brine temperature control loop was changed, resulting in a higher average brine temperature in the cell during ambient temperature changes, decreasing electrical resistance and lowering voltage during cooler ambient temperatures. Analyzing the variation due to anode adjustment was more difficult. To do this, regression techniques were used to develop a mathematical model to predict voltage drop where all components except anode gap are taken into account. The difference between the voltage thus calculated and the actual voltage would be the contribution due to the anode-cathode gap. A computer program was developed to calculate and report this value in real time. Operators were trained and project implementation begun. Annualized energy savings are approximately 0.85% per unit of production.

Number:	13
Company:	**Equistar Chemicals, LP**
Category:	Energy Efficiency Program - Corporate/Business Unit
Entity:	Corporate/ Business Unit
Title:	Energy Best Practice Team

Description: Equistar Chemicals, LP is a joint venture between Lyondell Chemical Company, Millennium Chemicals Inc. and Occidental Petroleum Corporation, formed in December 1997. The challenge was to identify best practices between the three companies and to implement the best practices throughout Equistar. Projects were limited to those with less than a one-year payback. An Energy Best Practice Team was formed to reduce Equistar's energy costs. The team is lead by an energy manager and supported by a full-time energy engineer. Energy teams led by senior engineers were formed at fourteen plant sites and meet monthly to discuss opportunities, report progress and discuss action plans. The energy manager, energy engineer and energy team leaders have monthly phone conferences to discuss goals, new projects and team initiatives. Quarterly meetings of site representatives are held to discuss goals, review the most recent projects implemented, and listen to presentations from site energy teams and industry experts. By maintaining a focus on energy cost reduction, low- and no-cost energy projects are continually implemented. Energy best practices have been identified and plants conduct annual self-assessments to the practices. Energy audits have been conducted at each site. Through sharing of these developed best practices with other Equistar sites, energy savings ideas can be multiplied at a faster rate. Of fifty-two projects implemented so far, almost all were procedural changes or required minimal maintenance expense. Annualized energy savings in 1999 were 1,971,000 MMBtu, or 5.4% per unit of production.

Number:	14
Company:	**Bayer Corporation**
Category:	Significant Improvement in Manufacturing - Plant Site
Entity:	New Martinsville, West Virginia Plant Site
Title:	Utilization of Plant Produced Excess Hydrogen

Description: A decision was made to shut down permanently several operating units at this site which produced intermediate products, and to produce these products at an alternate corporate site. One of the units to be shut down used hydrogen as a raw material. The hydrogen was produced on site from the reforming of natural gas, in a reaction which also produced carbon monoxide. The carbon monoxide is a very significant raw material for other production operations at this site and it was essential to continue the supply of carbon monoxide for this purpose. However, no other production units at this site used hydrogen as feedstock. Flaring the hydrogen to the atmosphere was considered unacceptable. Therefore, an alternative productive use for the hydrogen had to be found. Possible alternatives investigated included merchant sales, use in fuel cells for onsite electricity generation, hydrogen-fired cogeneration and co-firing the hydrogen in existing boilers for process and heating steam generation. The decision was to expand existing facilities for burning hydrogen in utility boilers for plant steam supply. A multi-boiler installation was used. The burner, piping, auxiliaries and safety provisions for each boiler were modified in compliance with all corporate, regulatory and insurance requirements. The burner management systems and controls were upgraded to a programmable logic control (PLC). The resultant use of an increased quantity of hydrogen resulted in a corresponding decrease in natural gas used for fuel. Greenhouse gas emissions also decreased. Annualized energy savings are approximately 380,000 MMBtus, or 6.3% of total site energy consumption.

Number: 16
Company: **DuPont**
Category: Environmental Impact - Operating Unit
Entity: Victoria, Texas Power
Title: Reduction of NOx Emissions and Fuel Gas in the Hydrogen Reformer Furnace

Description: New low-NOx natural gas fired burners, installed in the hydrogen reformer furnace in 1995, were unable to meet permit requirement for NOx emissions. Large, billowy yellow flames were constantly "licking/impinging" on newly replaced process tubes, threatening damage and shortened life. Investigation revealed the burners were sized for a heat load 40% higher than furnace demands, resulting in low fuel tip gas velocity with very poor mixing and burning. In addition, the 19" diameter burners were designed using erroneous firebox vacuum data and a BTU assumption 40% too high, resulting in a 200% over sizing of the burner throat areas. The over sized burner tips and burner throats were the reason the burners could not meet NOx requirements. Smaller burner tips were ordered from the OEM and installed. The 19" burners were fitted with restriction plates conceived by area technical personnel to reduce the cross sectional area at the throats to 13" 14" and 15" in the respective cells. Finally, earlier modifications to the burner air registers, which had the unintended effects of impairing the ability to control oxygen and routinely causing the burner air register push rod mechanisms to jam, were removed and the air registers restored in original condition. Additionally, reformer process tubes were fitted with newly-designed upper tube seals to prevent tramp air from entering the furnace. These various changes resulted in reduction and stabilization of NOx emissions, greatly improved operational control, restored maximum hydrogen capacity (which had been limited to 85%), and improved fuel efficiency. Annualized energy savings are approximately 35,600 MMBtu, or 4.6% per unit of production.

Number: 18
Company: **Bayer Corporation**
Category: Energy Efficiency Program - Plant Site
Entity: Bushy Park, South Carolina Plant Site
Title: Bushy Park Plant Site Compressed Air

Description: The existing plant site compressed air system consisted of three large centrifugal compressors, three screw-type air compressors, two reciprocating air compressors with associated receivers, dryers, filters, distribution headers and controls. For a number of reasons the system was not operating at optimum efficiency. A corrective action team, consisting of plant personnel and with support from engineering, operations and maintenance resources, systematically addressed and resolved numerous problems with the system. a) Cooling water. Impurities were addressed by installing oxygen reduction potential controllers and slipstream filters. Cooling water takeoff was moved to the top of the water supply header and a corrosion inhibitor treatment program begun. b) Air dryer. A purge airflow restriction orifice plate was resized and three-way lubricated control valves on a heated dryer were upgraded. c) Pressure drops. Unnecessary check valves were removed and an undersized 2" flow meter was bypassed. Air filters are now monitored and changed regularly. d) Air losses. A leak survey of the entire manufacturing site was conducted and remedial action undertaken. Solenoid-operated condensate blow down valves were replaced with compressed air condensate drain traps. e) Large instantaneous increases in air demand. The locating and correcting of leaks enabled provision of the quantity of air needed to respond to instantaneous peak demands. f) Maintenance. A quarterly preventive maintenance program, including oil analysis and vibration analysis, was established. g) Training. Operators were trained to improve the consistency of plant operation. The environmental, energy efficiency and operational benefits of these measures exceeded expectations. Annualized energy savings (electricity for compressed air) are approximately 52,150 MMBtu, or 23%.

Number:	19
Company:	**ExxonMobil Chemical Company**
Category:	Significant Improvement in Manufacturing - Plant Site
Entity:	Baton Rouge, Louisiana Complex Cogeneration Project
Title:	Major Energy Savings Plus Environmental Improvements Through Expanded and Modernized Cogeneration

Description: The very large refining and petrochemical complex of ExxonMobil in Baton Rouge continues to experience significant growth in its need for electricity. The Complex had an aging cogeneration plant with power boilers which provided nearly 25% of its medium pressure steam supply and about 30% of its electricity through steam turbine generators. Another 15% of the Complex's electricity needs was purchased from the local utility, which used conventional generation. In addition, the boilers had significant NOx emissions, and reliability of the aging plant infrastructure was a significant concern. This project entailed installation of a new, highly efficient, state-of-the-art gas turbine generator with a large heat recovery steam generator, and slowed/idled the aging, higher emissions boilers. As a result of this project the entire electrical needs for the Complex are met through cogeneration with an additional 70-200+ MW, depending on the season and climate conditions, available for sale to other consumers. With new gas turbine emissions of less than 10 ppm NOx, total plant emissions even with the much higher output are lower than before. In addition, the surplus electricity sold to the local utility or the wholesale market reduces third party fuel use and emissions by trimming less efficient generation at the utility. Fuel efficiency for site steam generation has also been significantly improved and the overall site reliability greatly enhanced through significant replacements and upgrades of the aged infrastructure. Annualized energy savings are approximately 8,355,000 MMBtu, or 19.2% per unit of production.

Number: 20
Company: **ExxonMobil Chemical Company**
Category: Significant Improvement in Manufacturing - Plant Site
Entity: Baton Rouge, Louisiana Plastics Plant Site
Title: Reactor Preheat Modifications

Description: The challenge was to increase production capacity and at the same time reduce unit energy consumption on the E-Line Reactor. Rigorous techniques of risk analysis and value engineering on the process flow and reactor designs were used to identify and evaluate project alternatives. As a result, the reactor line was reconfigured to reduce consumption of high-pressure steam to preheat the reactor feed, produced by gas-fired boilers, and a boiler was installed to generate low-pressure steam from process heat. Consumption of high-pressure steam was reduced more than 40% per unit of production, and about 5,000 lb/hr of low-pressure were generated by the boiler using the previously unutilized process heat. Surplus low-pressure steam is now exported from the area for use elsewhere at the site, further reducing demand from natural gas fired boilers. In addition, electricity consumption for the process was reduced by supplying higher pressure ethylene to the compression train, modifying the polymer extruder, and modifying the reactor to increase the conversion of monomer to polymer. A further benefit of these changes was the reduction or elimination of infrastructure capital investment – boiler capacity, power distribution and cooling tower expansion – that otherwise would have been required for the added production volume. Annualized energy savings are approximately 671,000 MMBtu, or 25.6% per unit of production. ExxonMobil is now licensing this technology.

Number: 21
Company: **BASF Corporation**
Category: Energy Efficiency Program - Corporate/Business Unit
Entity: BASF Corporation
Title: Energy Management Program

Description: In 1993 BASF Corporation's Executive Committee established an Energy Management Program, in line with the voluntary guidelines in the American Chemistry Council's Energy Efficiency Continuous Improvement Program, to develop the potential for energy efficiency improvements. An Energy Management Steering Committee, consisting of group vice presidents and manufacturing directors and chaired by a division president, was put in place to foster an awareness of energy savings' importance and potential and to guide development and implementation of the program. An Energy Management Group was constituted to provide centralized technical support to the sites, monitor performance and report results to the Executive Committee on a regular basis. Noteworthy aspects of the program included the conduct of energy surveys at numerous sites; establishment of a company award program; and, publication of personal and team accomplishments in the corporate newsletter. Each plant focuses on its best energy savings opportunities based on that plant's business environment, expansion plans, infrastructure requirements, capital availability and operating costs. Many sites

developed quantitative and qualitative mid-term energy goals, and many sites have already achieved their goals. New facilities are designed with the latest in energy efficient technology and utilize the latest tools for process optimization and heat integration. Expanding energy requirements at these sites have been met by high efficiency cogeneration plants. As a result of these activities, BASF Corporation has demonstrated continuous improvement in energy efficiency since 1991. Between 1990 and 1999, purchased energy per pound of production has decreased 40%. In absolute terms, purchased energy use has declined almost 10% even as production has increased more than 50%. In 1999, annualized energy savings were approximately 5,250,000 MMBtu, or 10% per unit of production.

Number:	22
Company:	**BASF Corporation**
Category:	Energy Efficiency Program - Corporate/Business Unit
Entity:	BASF Corporation
Title:	Motor Management Guideline

Description: An initial survey within BASF Corporation revealed a vast number of differences in motor management procedures, and no one method that was entirely correct. Consequently a Motors Team was established in 1998 consisting of representatives from the largest manufacturing sites, Corporate Engineering, Corporate Energy Management and one outside consultant. The Motors Team was charged with developing a Guideline that would apply to all of the company's business units and manufacturing sites. Given the different levels of engineering staff and guidance at the various sites, the Motors Team needed to develop a Guideline that addressed technical issues surrounding motor management while presenting this information in an easily usable format. The Guideline could then be the basis for site-specific motor management policies, but was complete enough to adopt "as is". Over a one-year period the Motors Team addressed a myriad of electric motor issues. Its starting point was the examination of existing programs such as *Motor Master Plus* and other "canned" programs available on the market. When complete, the new BASF Motor Management Guideline was introduced in a series of roll-out presentations at key regional company facilities. A tracking procedure was established using an accounting software program (SAP) which is employed for maintenance management. The estimated potential energy savings through this program are in the 3-5% range. Annualized energy savings in 1999 were approximately 50,000 MMBtu. Expected annualized energy savings when the program is fully implemented are approximately 300-400,000 MMBtu.

Number:	24
Company:	**Eastman Chemical Company**
Category:	Significant Improvement in Manufacturing - Project
Entity:	Polymer Intermediates Department, Carolina Operations
Title:	Reduce Cooling Tower Water Demand

Description: Process cooling in a process in the department is provided by a cooling tower, river water and chilled water. Process improvements had been made to increase production output and the additional demand exceeded the capacity of the cooling tower. This project included alterations to maintain the critical process temperatures and increase the temperature setpoints on components of the process to optimize the cooling tower capacity and optimize process heat. Process instrumentation was used to identify all process conditions. Piping and instrument modifications were made to obtain optimum conditions. These changes lowered the water flow through the tower by 12,500 gallons per minute and improved the efficiency of the cooling tower. Reduced water flow in turn resulted in a substantial reduction in electrical energy demand. These changes deferred the cost of a new cooling tower cell, deferred the cost of modifications to the river water system, and decreased electrical energy costs. Annualized energy savings in 1999 were 54,000 MMBtu, or 39%.

Number:	25
Company:	**Eastman Chemical Company**
Category:	Environmental Impact - Project
Entity:	Polymer Intermediates Department, Carolina Operations
Title:	Reduce River Water Demand in Polymer Intermediates Processes

Description: Much of the process cooling in the polymer intermediates chemical processes is provided by river water. In the past, river water usage in all intermediates process areas normally was much higher than needed for proper operation of the processes. This required more high and low pressure river water to be pumped around the plant and also required running more pumps than needed. Sometimes, when the river level was low, the high river water usage resulted in problems such as process capacity limitations and/or increased costs due to paying for additional water release from the dam upstream of the plant site. Process instrumentation was used to identify all process conditions. Optimum flow and temperature conditions were identified and piping and instrumentation modifications were made to obtain these conditions. River water flow to the process heat exchangers was reduced by manually throttling river water flow, creating river water flow control loops using existing equipment, or increasing the temperature setpoints on some components of the process. Physical changes to plant and equipment consisted of installing one new control valve, repairing several existing control valves, re-labeling wiring, transmitters and control valves and updating DCS and drawings. As a

A new feed injector was installed and safety controls added to an existing programmable logic control system. Implementation of this project resulted in reduced incineration of co-products and backed out consumption of natural gas and other feeds to the gasifier. Annualized energy savings were approximately 244,000 MMBtu, or 13%.

Number:	29
Company:	**Eastman Chemical Company**
Category:	Significant Improvement in Manufacturing - Project
Entity:	Utilities Department, Texas Operations
Title:	New Controls Upgrade Boilers' Efficiencies

Description: Texas Operations has four 600-psig boilers that were originally designed to burn natural gas, but now burn a mixture of natural gas and plant off gas. The composition of the fuel varies frequently and quickly, causing the fuel's heat value to swing tremendously. When the fuel gas was changed to a mixture of natural gas and plant off gas, the original pneumatic combustion control systems could not handle the fluctuations in heat value without major changes to the control systems. The controls were set up and tuned to provide more combustion air than required in order to maintain an adequate safety margin during "automatic" operation. The boilers could not be run at their optimal efficiency. To address this problem, a redundant calorimeter system was installed to measure the fuel's heat value. A DCS (distributed control system) was installed to optimize the combustion controls. Electronic instrumentation was added to increase the data reliability. The new controls system now predicts the airflow needed for a given fuel flow to account for the fuel's changing heat value. Instead of having preset conditions that don't meet all operating scenarios, the boilers now have controls that respond to them. More control allows operations to run with less airflow, increasing the boilers' efficiencies because heat is transferred to the water instead of to the excess air. Annualized energy savings were approximately 120,000 MMBtu, or 3%.

Number:	30
Company:	**Eastman Chemical Company**
Category:	Energy Efficiency Program - Operating Unit
Entity:	Epolene/Eastoflex Department, Texas Operations
Title:	Energy Savings through Process Improvement and Simplification

Description: Plant personnel recognized that opportunities existed to reduce steam usage through better understanding of metering and reporting, and by closing the gap between actual usage and theoretical requirements. First, the metering system was brought into shape to provide the tools for evaluation and verification of future reductions. Once the direction and magnitude of all steam and condensate flows were known, weekly totalizer readings and a detailed spreadsheet showing the steam breakdown by area provided a structured and disciplined framework that greatly aided efforts. Involved personnel then started a two-fold approach of closing the energy balance around each major steam user and evaluating whether the unit was required for continued operation. Specific efforts resulting in reductions included 1) elimination of process vessels and heaters that were found to be unneeded; 2) improved understanding of the characteristics of the different steam traps used; 3) an aggressive external leak reduction program, and 4) evaluation of internal steam leak paths (bypasses), which were either eliminated or fitted with flow restricting devices. Annualized energy savings were 114,000 MMBtu, or 48% of steam-related energy usage.

Number:	32
Company:	**Eastman Chemical Company**
Category:	Significant Improvement in Manufacturing - Operating Unit
Entity:	No.2 Olefin Department, Texas Operations
Title:	Modify Eastman PSA Unit Mode of Operation to Recover Off-Gas for Waste-Heat Boilers

Description: A Pressure Swing Adsorption (PSA) unit is used in one of Eastman's hydrocarbon cracking plants to produce high purity hydrogen from a fuel-gas stream containing methane and hydrogen. The PSA unit was originally configured to operate in one of two modes: 1) High Pressure mode for normal hydrogen production with fuel-gas (primarily methane) recovery, and 2) Low Pressure mode for maximum hydrogen production with no fuel-gas recovery. The Low Pressure mode was used when plant hydrogen demand exceeded available supply. In this mode, however, the residual fuel-gas stream had to be flared due to insufficient pressure to return the stream to the process. A project was undertaken to provide for a third mode of operation: Moderate Pressure mode. Company personnel consulted with the PSA manufacturer to have the operating parameters adjusted for the Moderate Pressure mode. New piping and pressure control systems were installed to regulate the pressure in the off-gas stream that feeds the waste heat boiler burners. Then, new operating software from the PSA manufacturer was installed in the PSA unit's dedicated PC. Operating pressure for the PSA unit was manually adjusted to the new Moderate Pressure mode and then automatically controlled with the new operating software. The Moderate Pressure mode is now the normal mode of operation. In this mode the PSA unit can produce high purity hydrogen at 94% of maximum hydrogen production capability and also recover 100% of the residual fuel-gas stream by re-routing the fuel-gas to an alternate user, the waste heat boilers. The project resulted in a reduction in operating costs as well as reduced use of the flare. Annualized energy savings are approximately 73,015 MMBtu, or 1.5%.

Number:	33
Company:	**Nalco/Exxon Energy Chemicals, L.P.**
Category:	Non-Manufacturing Improvement - Corporate/ Business Unit
Entity:	Sugar Land, Texas Research Facility
Title:	HVAC Energy Conservation Upgrade Project

Description: The Company's Corporate Administration Offices and Research Facilities are comprised of four main buildings constructed between 1960 and 1984. Each building had its own independent HVAC system consisting of boiler, chiller(s) and air-handling units. Chillers and boilers were sized to provide comfort during peak demand periods during the year but remained in the same mode of operation during non-peak periods. Following a study of the situation, a project was undertaken to install a continuous loop system that would tie equipment from the existing HVAC systems together and allow for automated computer controlled operation. The study also indicated that the new loop would allow for some of the existing equipment to removed altogether, and for other equipment to be placed into a mode of emergency back-up only. The construction phase connected the four mechanical rooms by running approximately 1000 feet of 6" pipe and approximately 500 feet of 4" pipe to complete the chilled-water and hot-water loops respectively. In addition, variable speed drives were installed on four pumps and nine air-handling units. Temperature sensors were installed at various locations in the buildings to allow for automated control. Approximately 5 miles of control wiring was installed to operate the new controllers installed on the equipment via a digital control system (DCS) with a computer interface. (The DCS system can be accessed remotely via modem by Maintenance Department Staff to inspect the operational status of the system and determine if any adjustments are needed.) One air-handling unit, two boilers and three chillers were taken completely out of service, and one boiler and one chiller were placed into emergency back-up mode. Annualized energy savings are approximately 48,245 MMBtu, or 33.7% of total energy consumed within the four buildings.

Totals:	Nominations:	33 from 11 companies
	Winners:	23 from 10 companies

performance

raised to the power of El Paso

Developing New U.S. Natural Gas Supply Sources

February 13, 2001

elpaso Merchant Energy Group

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Cautionary Statement Regarding Forward-looking Statements

This presentation includes forward-looking statements and projections, made in reliance on the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The companies have made every reasonable effort to ensure that the information and assumptions on which these statements and projections are based are current, reasonable, and complete. However, a variety of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this presentation, including, without limitation, oil and gas prices; general economic and weather conditions in geographic regions or markets served by El Paso Energy and Coastal and their affiliates, or where operations of the companies and their affiliates are located; inability to realize anticipated synergies and cost savings on a timely basis; difficulty in integration of operations; and competition. While the companies make these statements and projections in good faith, neither company nor its management can guarantee that the anticipated future results will be achieved. Reference should be made to the companies' (and their affiliates') Securities and Exchange Commission filings for additional important factors that may affect actual results.

Overview

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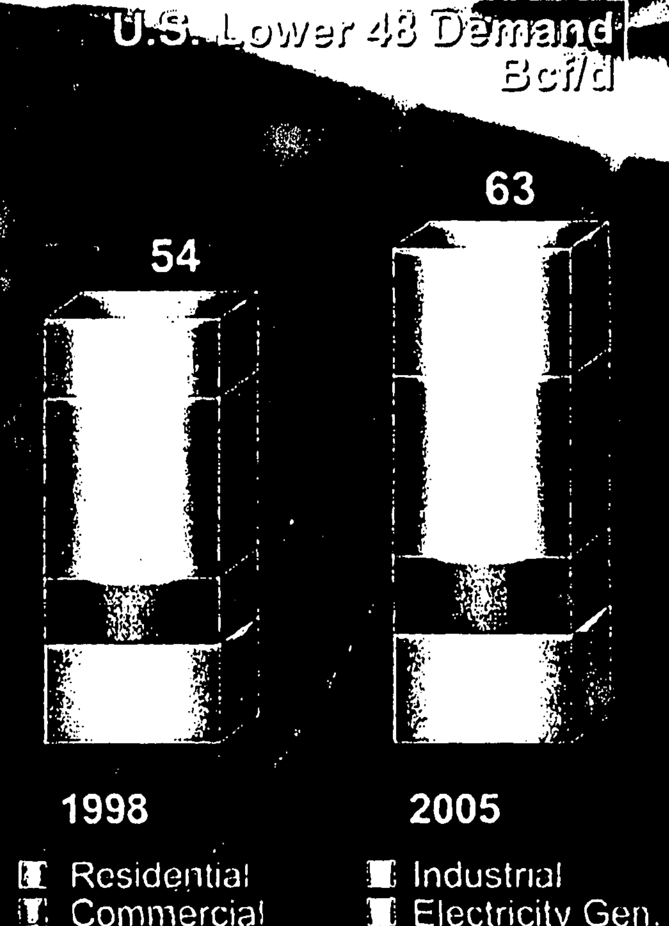
- Any comprehensive U.S. energy solution will require innovative thinking
  - U.S. will need significant additional gas supplies in the near future, especially near the coasts
  - There are few viable alternatives
- LNG should be an integral part of any U.S. energy solution
- Floating LNG terminals offer many unique advantages
- To promote growth of LNG, terminals need to be unregulated
- El Paso plans to aggressively expand LNG capacity

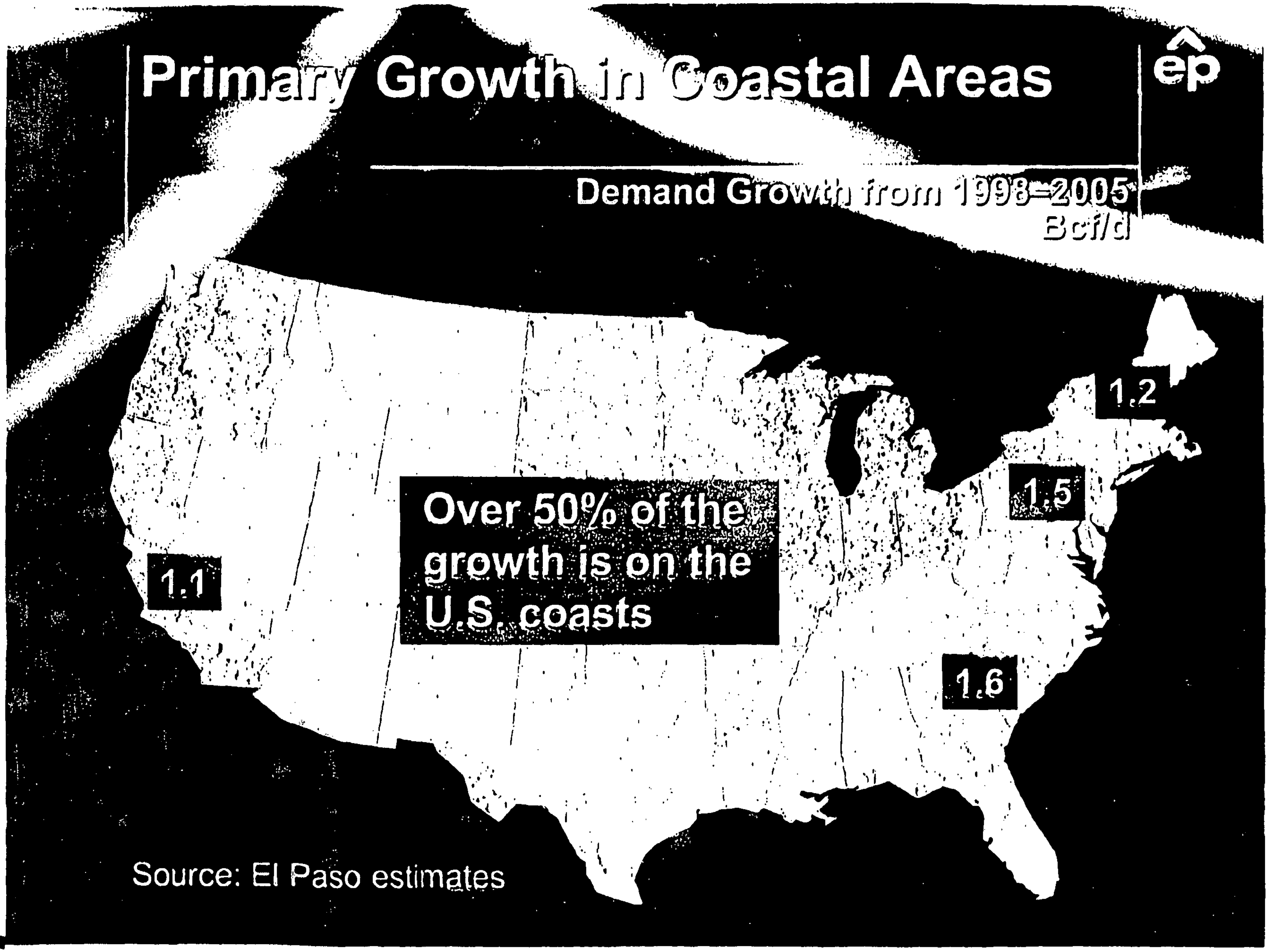
U.S. Natural Gas Market is Growing Rapidly

- U.S. natural gas demand is growing over 2% per year or approximately 1.5 Bcf/d per year
- Growth is led by the power generation market
  - NG consumption rate of growth for this market is almost 7% per year
  - Industry sources list 316,000 MW under some stage of development*



*At 100% utilization, a new 500 MW CCGT plant uses almost 100 MMcf/d

Source: El Paso estimates


Primary Growth in Coastal Areas
Demand Growth from 1998-2005
Bcf/d
1.2
1.5
1.1
1.6
Over 50% of the growth is on the U.S. coasts
Source: El Paso estimates

Gas Growth is Likely to Continue

- Electric generation will continue to be gas-fired
  - Gas-fired plants require lower capital costs and shorter construction lead times
  - 95% of all current electric generation development is designed to use natural gas
- New homes will increasingly choose natural gas as a source for heating
  - Natural gas costs less to heat a home than electricity, heating oil, propane, or kerosene
  - Heating an average home in a moderate climate costs 5% less to heat with gas than with heating oil and 33% less than with an electric heat pump
- Over 40% of U.S. factories use natural gas as their primary fuel source
- Natural gas is the cleanest and most efficient fossil fuel

U.S. L48/Canada Unable to Meet Increased Demand

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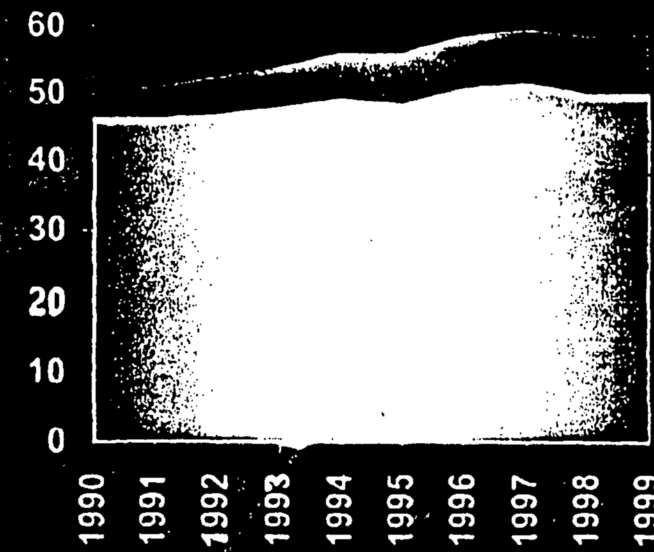
- U.S. production has been essentially flat for the last 5 years
- Canadian imports have been essential to meet growing demand, but are now under considerable production pressure

Supply and Source
Bcf/d



Source: EIA; National Energy Board (NEB)

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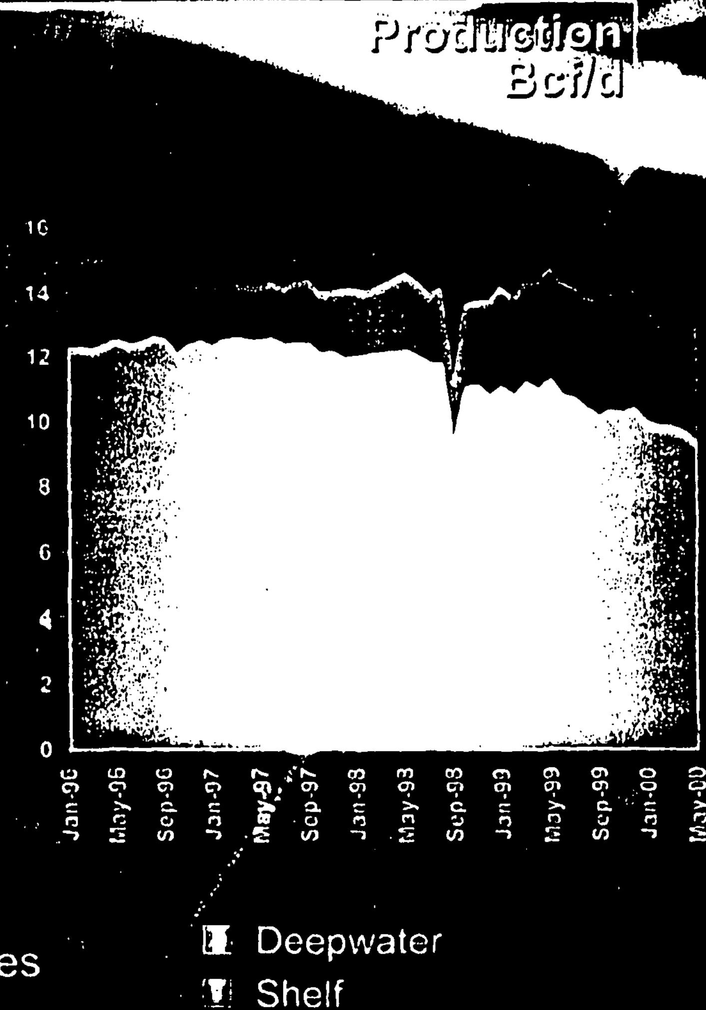
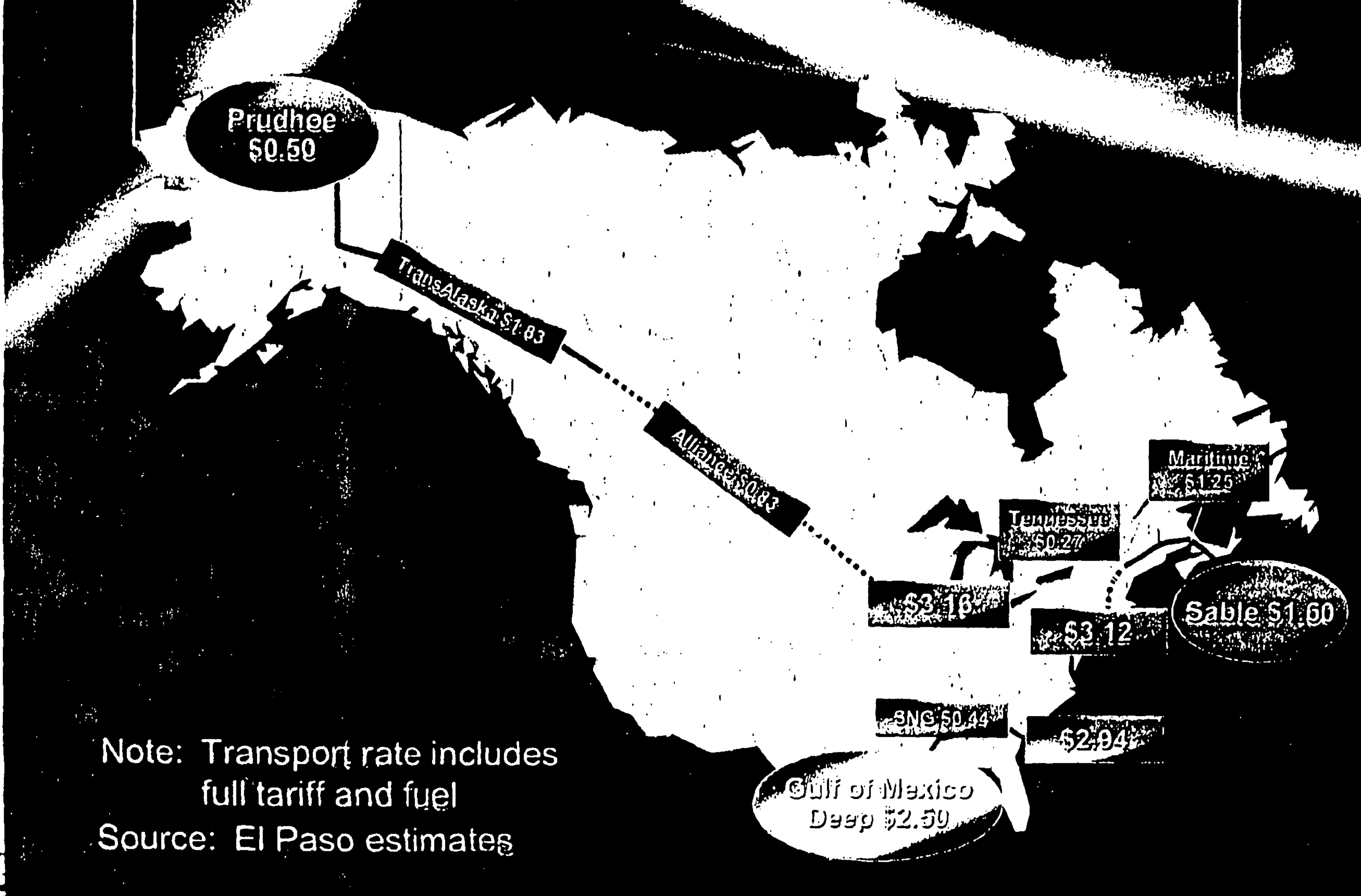
Gulf of Mexico Unable to Meet Increased Demand

- Gulf of Mexico production has been in decline the last 2 years
- Deepwater production to date has not been able to offset shelf declines



Source: Minerals Management Services

There are No Cheap Alternatives



Note: Transport rate includes full tariff and fuel

Source: El Paso estimates

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Longhaul Pipelines are Also Expensive

Estimate

- Representative tariff rate examples
  - Arctic Gas to Calgary $1.50–2.00/Dth
  - Alliance $0.77/Dth
  - Buccaneer $0.81/Dth
  - Southern Trails $0.67/Dth
  - M&NE $1.13/Dth

LNG Regasification: $0.25–0.50/Dth

Source: Literature search; Filed tariffs

DOE002-0539

Overview

- Any comprehensive U.S. energy solution will require innovative thinking
- LNG should be an integral part of any U.S. energy solution
  - LNG is most attractive solution
  - Existing terminals and new land-based terminals are only part of the answer
- Floating LNG terminals offer many unique advantages
- To promote growth of LNG, terminals need to be unregulated
- El Paso plans to aggressively expand LNG capacity

LNG is Most Attractive Solution

- LNG terminals currently exist in major demand growth regions on the East Coast
- Cost reductions have significantly reduced the landed cost of LNG
  - Liquefaction costs down 33% over the last 10 years
  - Shipping costs have decreased by 40%
  - Excess supply has led to reasonably priced spot market
- Facilities allow for baseload and peaking services at end of telescoping pipelines

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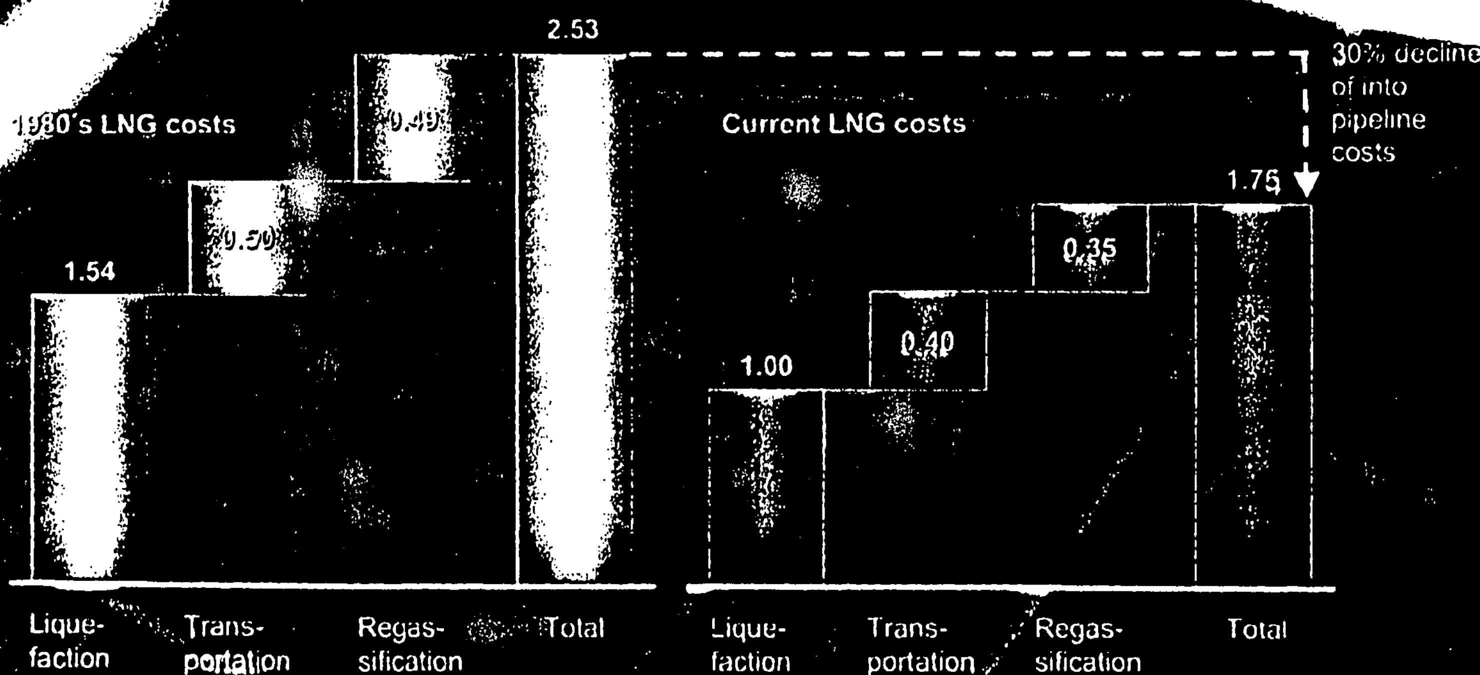
LNG Costs Have Been Steadily Falling

$/MMBtu—2,500 mile voyage



Note: Does not include feedstock prices
Source: McKinsey & Company analysis

Lower costs can improve netbacks or open additional markets, especially with higher gas prices

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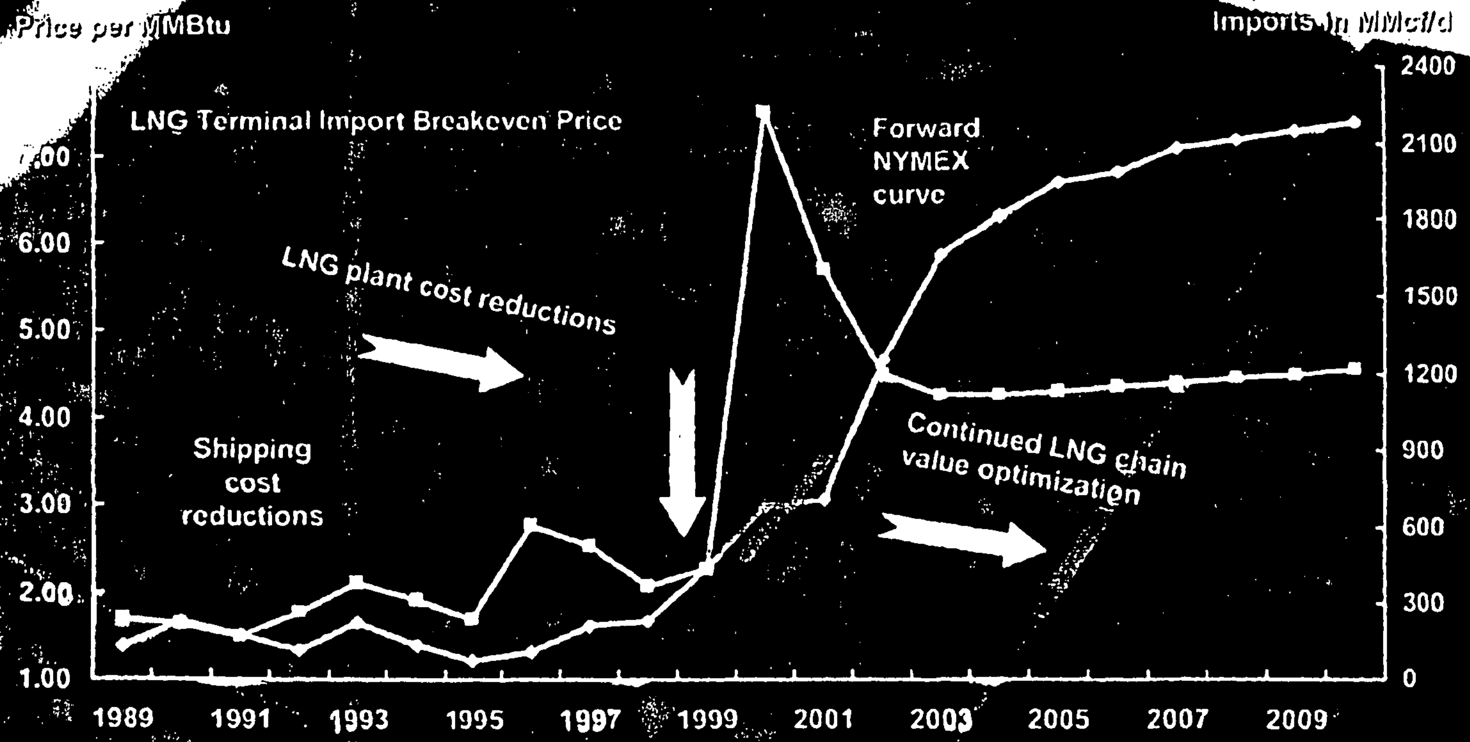
LNG Imports will Likely Increase



Source: El Paso estimates

LNG imports
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Currently Only Four U.S. LNG Facilities

- Everett: Operating since 1988 with long-term supply contracts
- Lake Charles: Operating since 1989 on a short-term, spot cargo basis
- Elba Island: To reopen October 2001
- Cove Point: To reopen mid-2002

U.S. Needs Additional Terminal Capacity

ep

Current Terminal Capacities
Bcf/d

Terminal	Send-out Capacity Bcf/d	Storage Capacity Bcf	Annual Capacity Bcf/yr.
Lake Charles	0.70	6.3	183
Elba Island	0.44	4.0	160
Cove Point	0.75	6.7	245
Everett	0.54	3.6	164
Totals	2.43	20.6	752

Source: Filed tariffs

Land Based Terminals Only Part of the Answer

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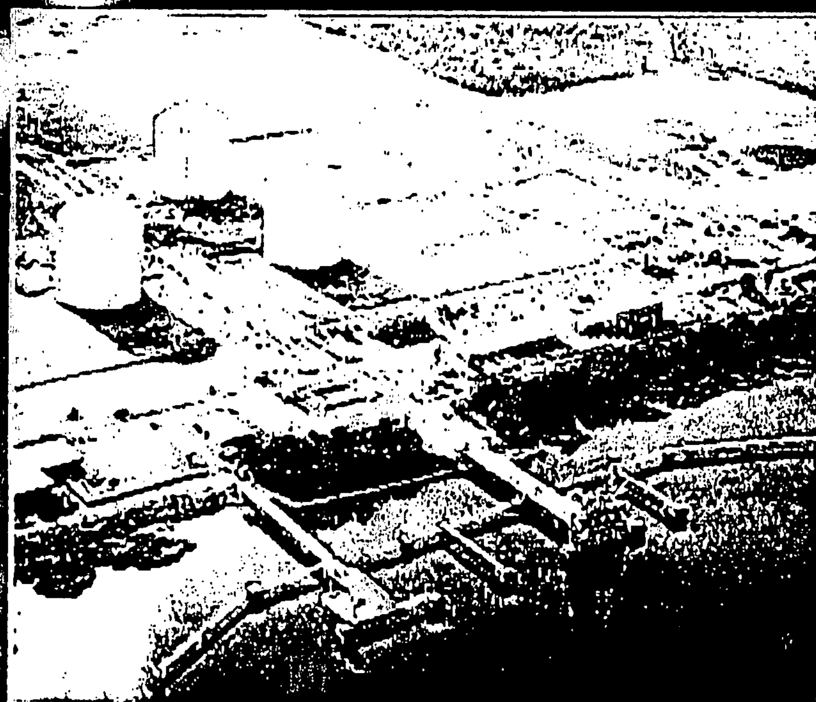


Advantages:

- Proven
- Scalable
- Reliable in harsh environment
- Creates optionality on pipeline system

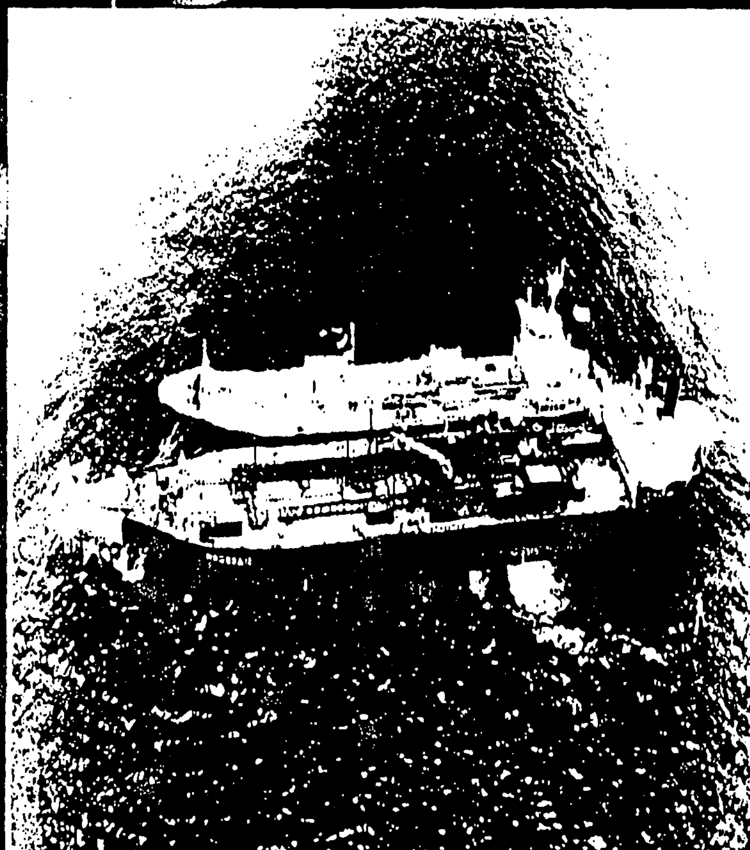
Disadvantages:

- Few "ideal" sites
- Longer development time
- Permitting issues

Overview

- Any comprehensive U.S. energy solution will require innovative thinking
- LNG should be an integral part of any U.S. energy solution
- Floating LNG terminals offer many unique advantages
  - El Paso developed stringent design requirements
  - Technology is proven
  - High availability is expected
- To promote growth of LNG, terminals need to be unregulated
- El Paso plans to aggressively expand LNG capacity

Floating Terminals Have Unique Advantages



An FSRU (Floating Storage and Regasification Unit) is a specially designed ship that has both storage and regasification facilities

Advantages:

- Environmentally friendly
- Mobile
- Can be delivered by 2005
- Proven tank design

Disadvantages:

- First-of-a-kind for LNG

El Paso Has Outlined Stringent Design Requirements

FSRU

- Offload ships in up to 3 meter seas
- Offload ships in 12 hours or less
- Continue vaporization in up to 10 meter seas
- Operating availability of 95–100%
- Stay on station during "100 year storm"
- 40 year life with no dry dock requirements
- Able to unload all existing ships > 70,000 CBM
- 24 hour/365 day operation
- Mobile (can be relocated seasonally)

- Potential design is an FSRU, which is very similar to an FPSO (floating, production, storage and offloading) and a modified LNG tanker
- Key element is liquids transfer between floating tanker and moored, floating storage vessel

Floating Terminals Have Unique Advantages

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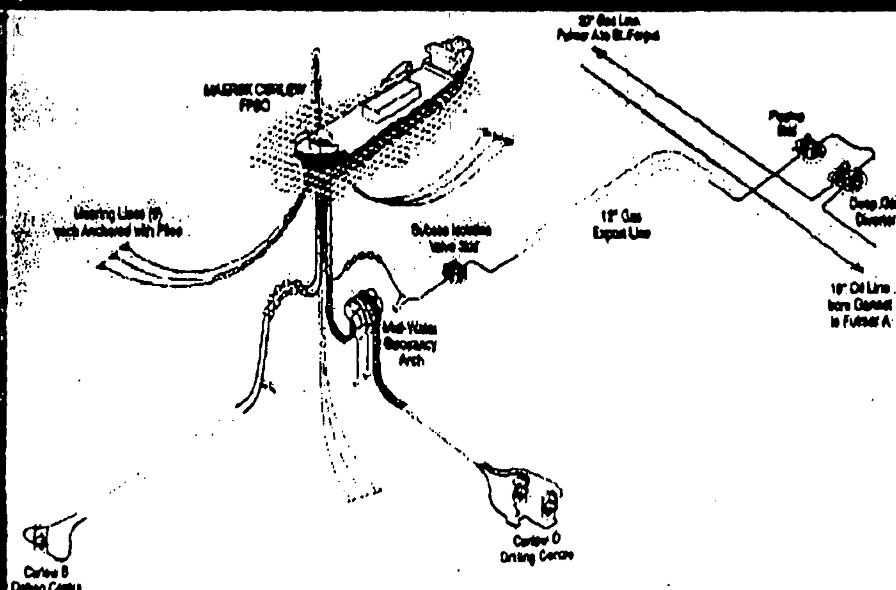
LNG Tanker with Regasification on board



Advantages:

- Environmentally friendly
- Extremely Mobile
- Can be delivered by 2004
- Scalable
- Proven tank design

Disadvantages:

- Not as much storage capability
- Only modified ships may connect to the buoy
- Longer send-out time (several days)

El Paso Has Outlined Stringent Design Requirements

Modified LNG Tanker

- Connect to buoy in up to 6 meter seas
- Volume send out tailored to market demand
- Continue vaporization in up to 10 meter seas
- Operating availability of 98–100%
- Stay on station during "100 year storm" with propulsion option available to evade storm if desired
- 40 year life
- 24 hour/365 day operation
- Extremely mobile (each cargo can be relocated seasonally)

FSRU and Modified LNG Tanker Employ Proven Technology

- Tanks: Will use 1 of 3 tank types that have been used in virtually all LNG Cargo Ships (Moss Dome, IHI SPB or GTT Membrane) for 25 years
- Mooring: Single Point Mooring System (SPM) allows the barge to weathervane and find the position of least resistance. Technology has been well proven in FSO's and FPSO's
- Unloading: Will unload in "side by side" configuration using unloading arms. Very similar to the operation at Elba Island terminal. Tandem unloading or the use of a flexible LNG hose may be developed if side by side actual or model results prove unreliable (FSRU only)
- Vaporization: Very similar to land-based terminals

- ABS and DNV ready to certify design and construction of FRSU
- DNV has concluded FRSU concept is feasible after review of design proposals

FPSOs Have Proven Track Record

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- FPSO's/FSO's have been in operation worldwide for 20+ years, including offshore U.S. (oil, LPG, etc.)
- Approximately 80 FPSO's currently operable
- Certified by all international maritime classification agencies (ABS, DNV, etc.) for oil, LPG, etc.
- Uninterrupted, safe operations through Force 12 ocean storms
- MMS has completed Draft Environmental Impact Statement for FPSOs in Gulf of Mexico

FSRU and modified LNG tanker have less environmental risk than oil–spilled LNG would vaporize

Cryogenic liquids transfer between two floating vessels successfully done under "emergency" conditions

High Availability Expected

Florida East Coast Study

- Florida East Coast Weather Conditions (28.5N,80.2W)

Significant Wave Heights Exceedance	%
1.0 meter	35
1.5 meters	15
2.5 meters	3
3.0 meters	2
6.0 meters	1

Wind Speed Exceedance	%
30 km/hour	19
40 km/hour	5
50 km/hour	1

FSRU cargo transfer limits

Modified LNG tanker connection limits

Bechtel indicates approximately 97% availability

Overview

- Any comprehensive U.S. energy solution will require innovative thinking
- LNG should be an integral part of any U.S. energy solution
- Floating LNG terminals offer many unique advantages
- To promote growth of LNG, terminals need to be unregulated
  - Floating terminals test current regulations
  - Regulatory environment may discourage investment in floating technology
  - El Paso recommendations
- El Paso plans to aggressively expand LNG capacity

Some FERC Legal Issues to be Resolved

Preliminary

Potential Jurisdiction	Applicability to Floating Platforms
Outer Continental Shelf Lands Act (OCSLA)	Must be determined if OCSLA extends jurisdiction over "artificial islands, and all installations and other devices permanently or temporarily attached to the seabed" that are not specifically for exploring, developing, or producing (no current precedent). Must be determined whether terminal and regasification facilities are deemed to be used "for pipeline purposes"
Section 3 of Natural Gas Act/Energy Policy Act of 1992	Must be determined if LNG is imported from a country with whom the U.S. has a free trade agreement and whether LNG imports are "first sales," which fall outside of Section 3 jurisdiction
Section 7 of Natural Gas Act	Must be determined if gas is involved in "interstate commerce". Must be determined if terminal and regasification facilities are deemed for transportation or "the production or gathering of natural gas" and whether are outside of territorial jurisdiction

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Regulations Discourage Investment in Floating Technology

Preliminary

Potential Regulations	Effect on Feasibility of Floating Platforms
Open Access	^ Intensifies the difficulty of coordinating shipping among multiple players – Number of ships required may change if terminal is moved – Voyage times and intervals may change ^ Provides disincentive to "prove" technology
Certificate of Public Convenience and Necessity	^ Limits floating terminals' unique ability to solve unsuspected problems – Unusual weather – Market disruption – Supply/demand imbalance

Overview

ep

- Any comprehensive U.S. energy solution will require innovative thinking
- LNG should be an integral part of any U.S. energy solution
- Floating LNG terminals offer many unique advantages
- To promote growth of LNG, terminals need to be unregulated
- El Paso plans to aggressively expand LNG capacity
  - El Paso is capable solution provider
  - Several attractive markets have been identified

El Paso is Capable Solution Provider

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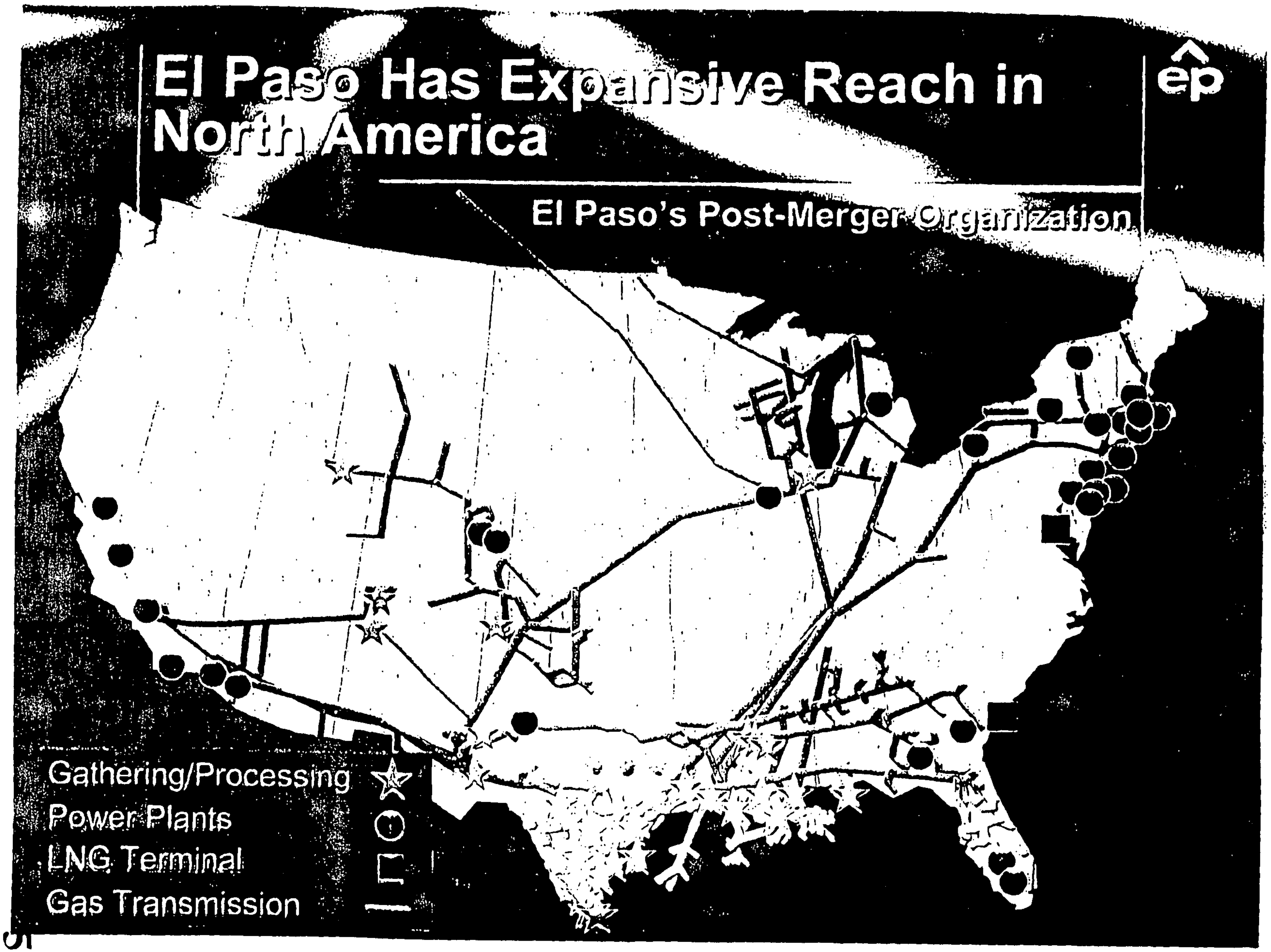
- El Paso is a major international energy infrastructure company
  - Active in 36 countries
  - Enterprise value over $50 billion
    - Production
    - Processing
    - Transmission
    - LNG imports
    - Storage
    - Wholesale marketing
    - Merchant power
- Emphasis on U.S., Canada, Mexico, Brazil, Argentina, Korea, and Southeast Asia
- Expanding European business to concentrate on gas and power trading, LNG, and selected power generation



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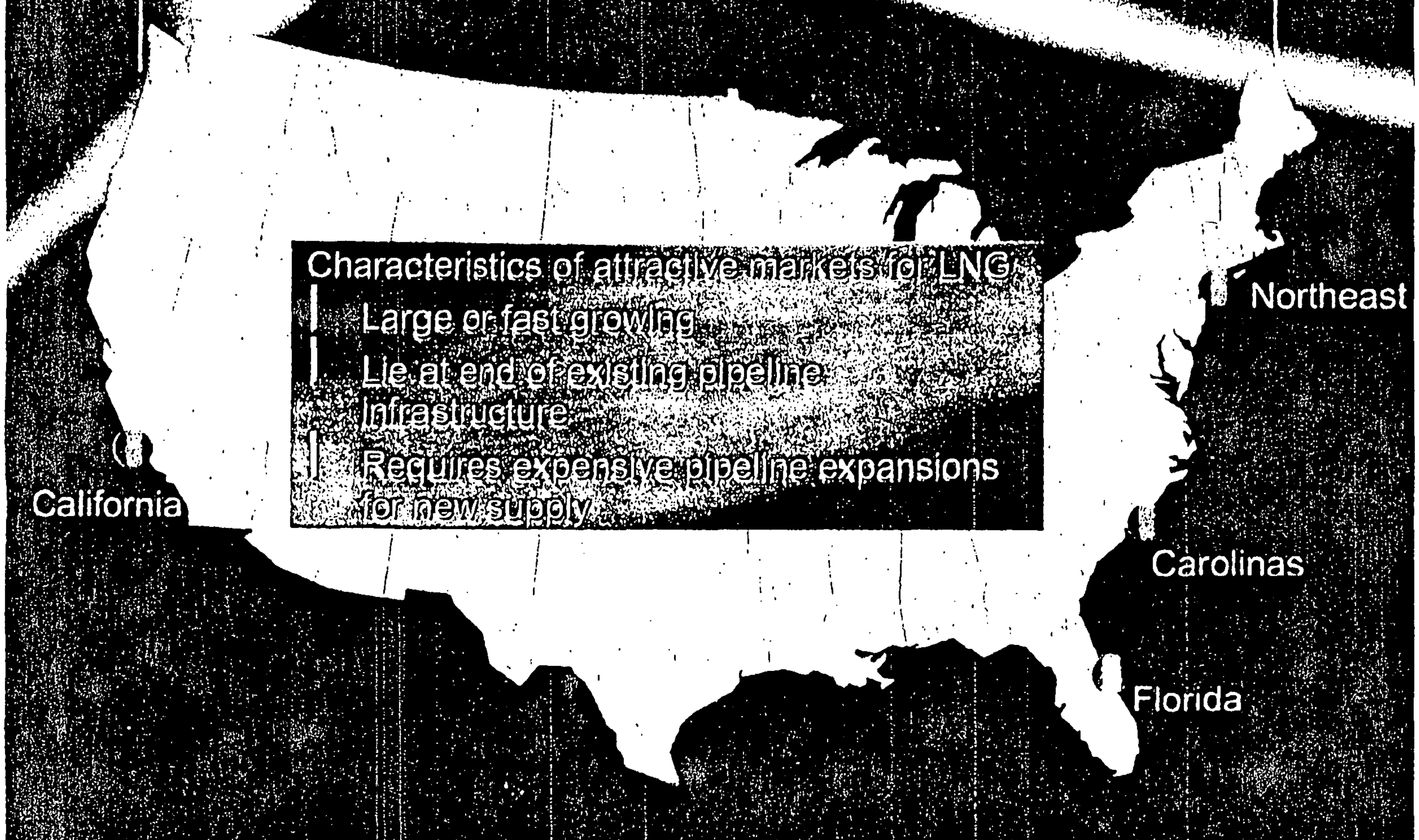
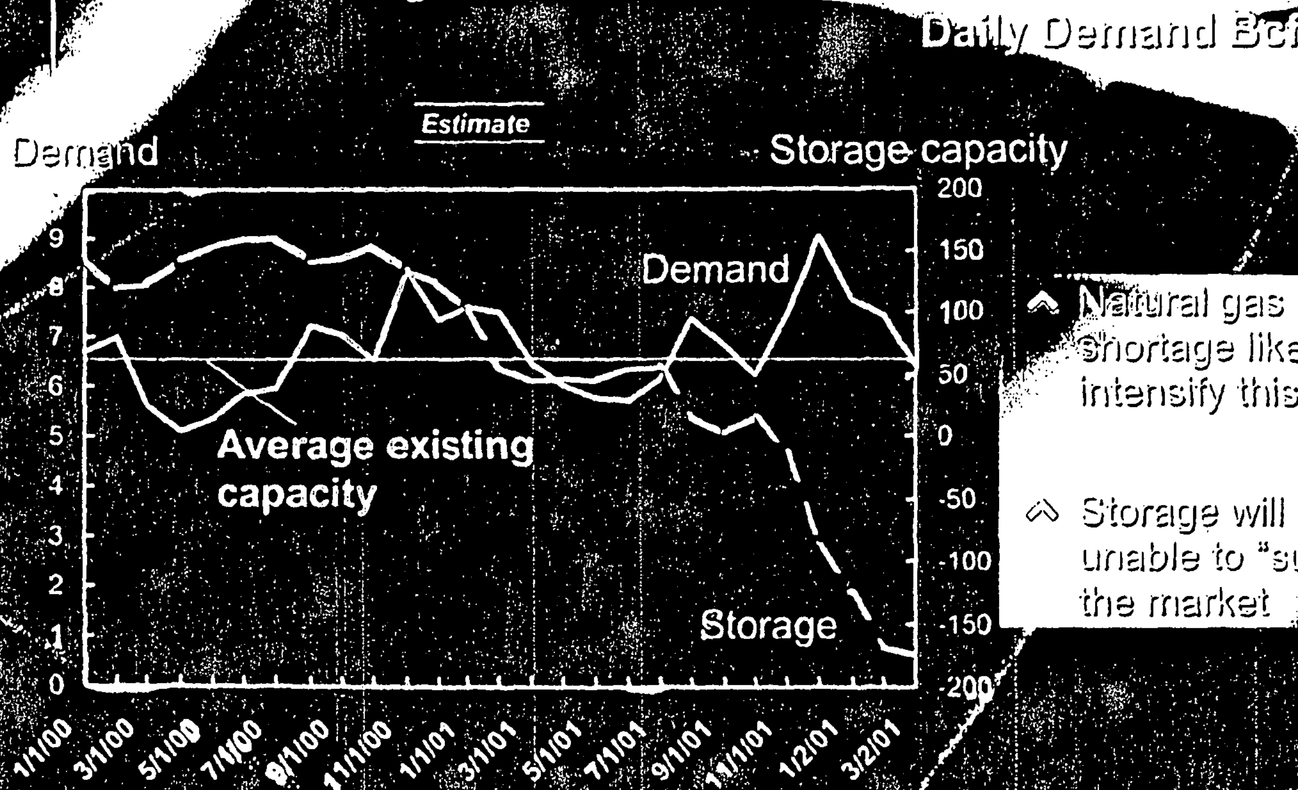
El Paso Has Identified Several Attractive LNG Markets



Characteristics of attractive markets for LNG:

- Large or fast growing
- Lie at end of existing pipeline infrastructure
- Requires expensive pipeline expansions for new supply

Gas Shortage in California May Get Worse



- Natural gas shortage likely to intensify this year
- Storage will be unable to "supply" the market

Source: EIA; SoCal Gas; CERA; McKinsey & Company analysis

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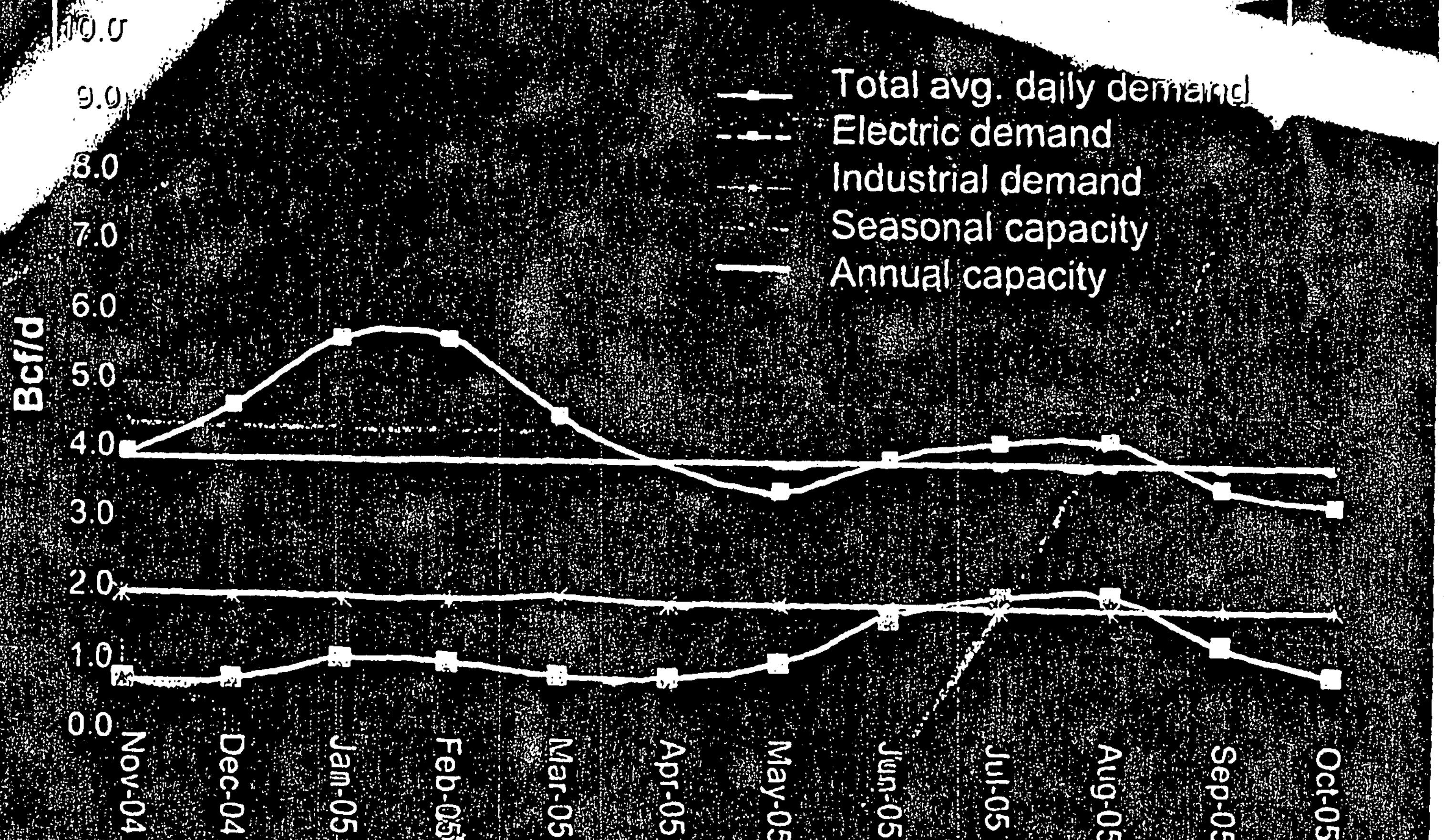
Southeast Capacity Constraints are Chronic by 2005



Source: Lukens Consulting Group

Capacity Constraints Currently Expected in Northeast

"New York reached $36.00 per MMBtu by second day of cold spell, and New England saw prices as high as $20.00"

–CERA, December 15, 2000

"The Northeast Region has several local areas where deliverability problems could increase"

–EIA, October 2000

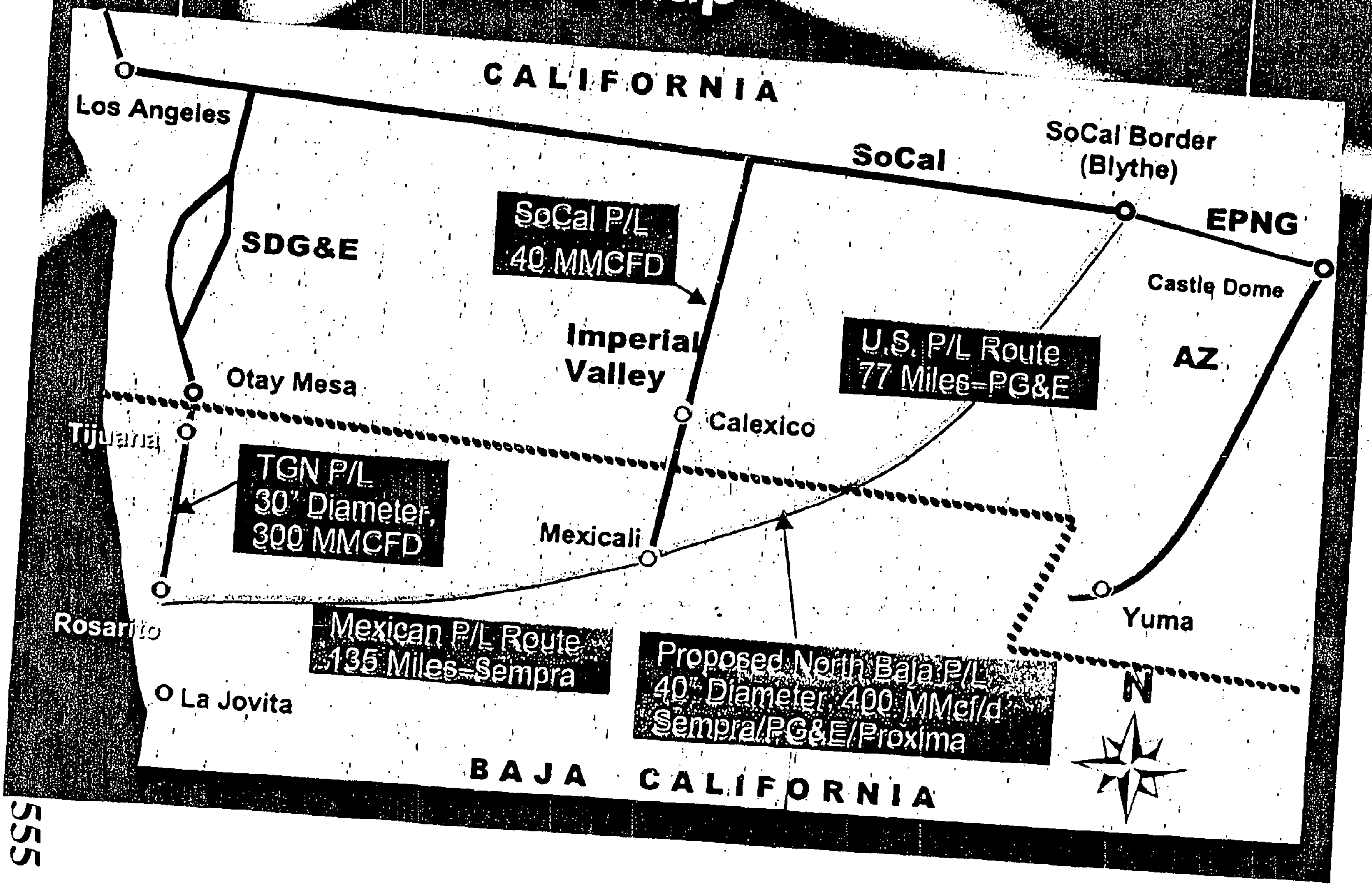
"In Boston, Massachusetts area, where pipeline capacity is already heavily utilized . . . demand is expected to grow rapidly over next several years"

–EIA, October 2000

"CERA is revising its estimated basis into New York to $2.25 on average for December and January"

–CERA, December 15, 2000

Southern and Baja California: Infrastructure Map



Southern and Baja California: Current Issues

- Sempra cannot provide "firm" gas to Mexico
  - Unable to provide true firm gas supplies: Non-Core Firm Service
  - Rosarito plant gas supply cut several times between November 2000 and February 2001
  - CFE concerned with security of supply and is considering re-bid of Rosarito supply
- Proposed North Baja Pipeline (NBPL)
  - Expression of interest was roughly 2 times the 400 MMcf/d pipeline capacity
  - May be possible to send 400 MMcf/d from EPNG and up to 400 MMcf/d from the proposed LNG regas terminal to meet demand
- FERV has expressed concerns regarding EPNG's ability to divert supply to Mexico and still supply California

Southern and Baja California: Current Issues

ep

- Otay Mesa Generating Company (OMGC) proposed 510 MW power plant
  - Duke's Intervenor plant in Encina may suffer increased curtailments if OMGC plant is supplied
  - Gas supply from an LNG terminal into the TGN pipeline will free up SDG&E capacity to serve its native load, alleviating this problem

Potential Current and Proposed Mexico Loads

Project	Company	MW	MMBtu	Status
Rosarito	CFE	550	90,000	Sempra current supplier
Rosarito	CFE	620	Fuel oil	Could be converted
Rosarito-Mexicali	Intergen/CFE	550	90,000	CFE Bid Awarded
La Jovita	AES	500	85,000	Proposed
City of Rosarito			40,000	Sempra current supplier
Total			**305,000**	

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Incremental Southern California Loads

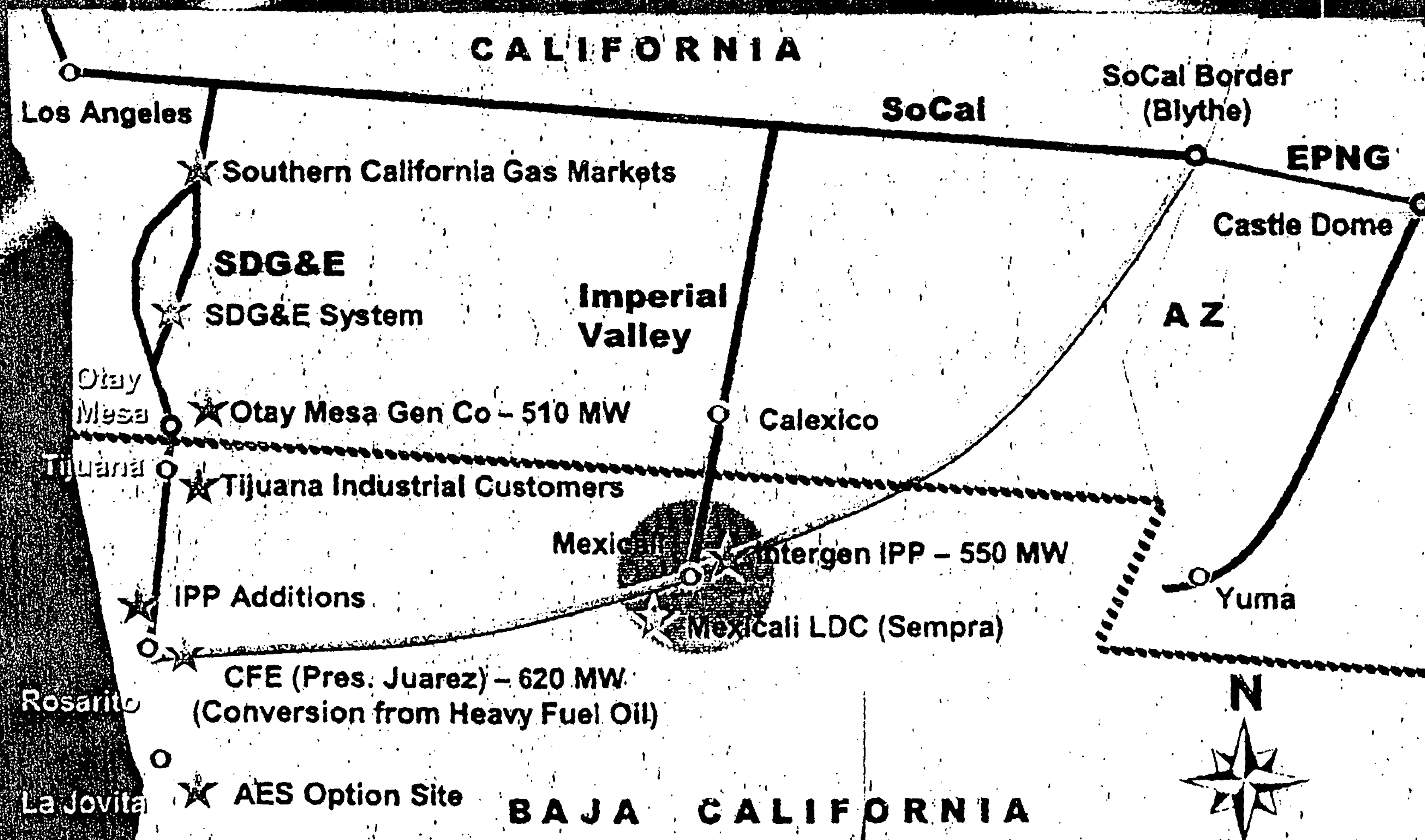
South of Los Angeles

Project	Company	MW	Regulatory Status
High Desert	Constellation	350	Approved
Nueva Azalea	Sunlaw Partners	800	Pending
Otay Mesa	PG&E Generation	510	Pending
Blythe	Summit Energy	520	Pending
Mountain View	Thermo Ecotek	1,034	Pending
Teayawa	Calpine	600	Pending
Long Beach		500	Not filed
Total		**4,314**	

800–900,000 MMBtu/d required

DOE002-0569

Potential Natural Gas Customers



DOE002-0570

LNG Regasification Terminal: Potential Gas Flows

ep

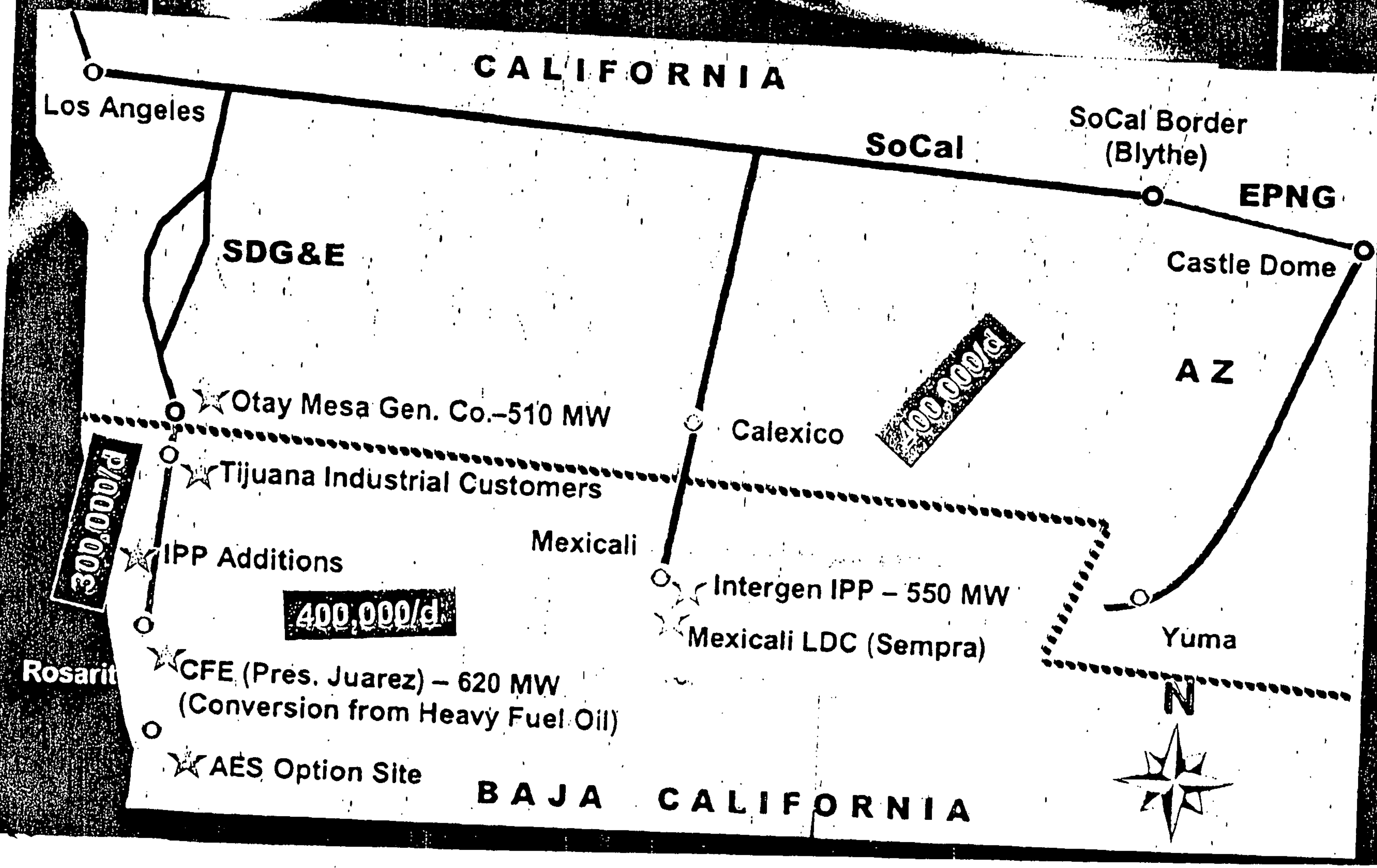
North to SDG&E's System, Tijuana customers, and the Southern California Market
200 MMcf/d to 300 MMcf/d

East along NBPL to Mexicali LDC and Intergen
200 MMcf/d to 400 MMcf/d

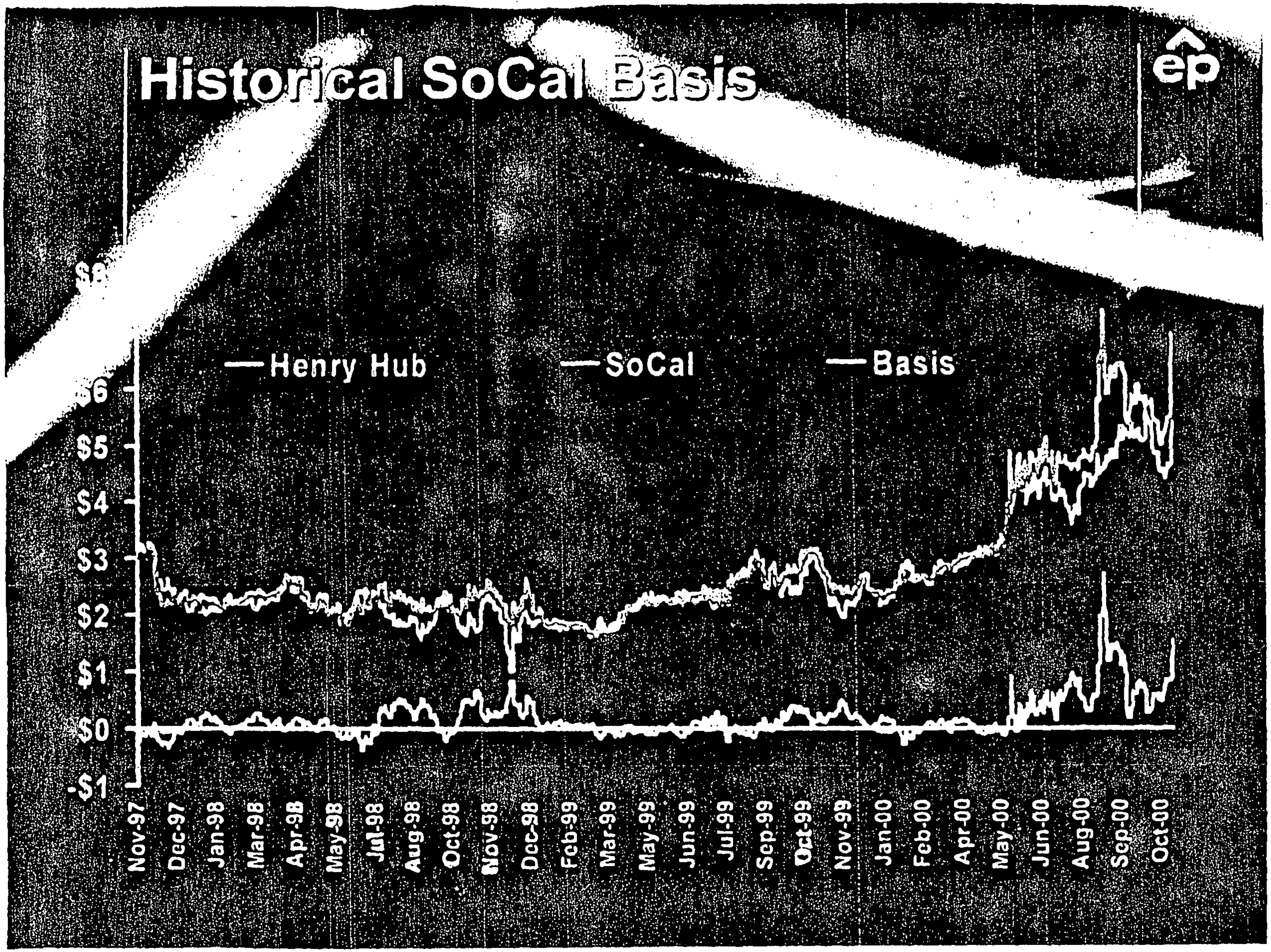
Locally in Rosarito for CFE plant conversions and new facility construction/expansion
100 MMcf/d to 200 MMcf/d

Total market in excess of regasification terminal capacity is 500 MMcf/d

Potential Gas Flows



DOE002-0572



DOE002-0573

563

To Improve Reliability and Lower Prices in California

ep

- New supply must enter the state
- Additional infrastructure is required north and east of the state
- Primary constraints are intrastate infrastructure; this must be alleviated
- Adding supply and infrastructure west and south of the state "beefs up" existing infrastructure

LNG provides the right mix of attributes necessary to dramatically improve gas deliverability and reduce price volatility in California

Energy's "Perfect Storm"

America faces an impending "perfect storm" in energy—both electricity and natural gas. Neither the Clinton administration nor the Congress has heeded the warnings over the last eight years. Left unchecked, the coming storm could dwarf the energy crisis of the 1970's.

The new Bush administration and Congress have the opportunity to steer clear of the coming storm or significantly reduce its potential damage. But they must demonstrate leadership by rolling-up their sleeves and going to work to enact simultaneously both comprehensive energy and environmental legislation. There cannot be one without the other.

A bipartisan solution is possible now because historically neither Democrats nor Republicans have laid claim to energy and environmental issues. The fault line on these issues has been between regions of the country and between producing and consuming constituents. The only time in the past that we've been able to build a consensus on these important issues is when a crisis is looming.

The cost of no rational energy and environmental policy is now obvious. Natural gas prices are skyrocketing. Inadequate supply due to hostility toward domestic production now cruelly coincides with the EPA's promotion of the fuel for all of the nation's combustion needs—from home furnaces to industrial processing to new electric power plants. Indeed, at least some versions of the Clinton Administration's Kyoto implementation schemes advocate a massive substitution of the nation's coal generation capacity with natural gas.

The electricity industry is not any better. Black outs and near misses driven by inadequate supplies, regional transmission constraints and spiking wholesale prices have been making headlines nationwide.

At the retail level, we have a patchwork of regulatory structures, with about one half of the states with de-regulation plans in place and the other half not even considering deregulating electricity. We have a Balkanized wholesale electricity market with price volatility and transmission constraints.

To understand the results of not squaring energy and environmental policy simultaneously, we have only to look to California, which is experiencing the first wind damage of the coming storm. Californians needed power but they were unwilling to approve the construction of new plants or to pursue aggressively conservation strategies that consumers would adopt. Due to environmental restrictions, no new power plants with significant capacity have been built in California in the past decade.

They wanted to have their cake and eat it too; abundant supplies of low-cost electricity but no new plants. They now know what happens when a booming economy and increasing population runs smack into a decade long freeze on new generation and transmission facilities. It's not deregulation (although their version is flawed) that is at fault but simply an imbalance of supply and demand—Economics 101—that has created the current problem.

The way forward requires a coordinated national energy and environmental plan that promotes investment in new technologies; new oil and gas production, building of new state-of-the-art coal and gas plants and de-bottlenecking of electric and gas transmission.

A balanced policy also must include comprehensive environmental requirements for older coal-fired power plants and emission guidelines for the life of new plants. It must include incentives for renewable energy and energy conservation.

It has been almost 23 years since the passage of major energy legislation, which came on the heels of the Arab oil embargoes of the 1970's and more than two decades of failed federal price regulation of natural gas. It is critical that we avoid polarizing rhetoric and face-up to the tough trade-off between the economy, environment and energy demands.

Clarity at the national level is desperately needed and the new administration and Congress have the opportunity to harmonize our twin goals of a clean environment and adequate energy to fuel our economy. Failure to do so guarantees that the coming storm will continue to strengthen and hit full strength.

James E. Rogers is Chairman, President and CEO of Cinergy Corp., one of the nation's leading diversified energy companies. He is a member of the Executive Committee and the Board of the Edison Electric Institute and Chairman of the their Environmental Policy Committee.

diversity in brief

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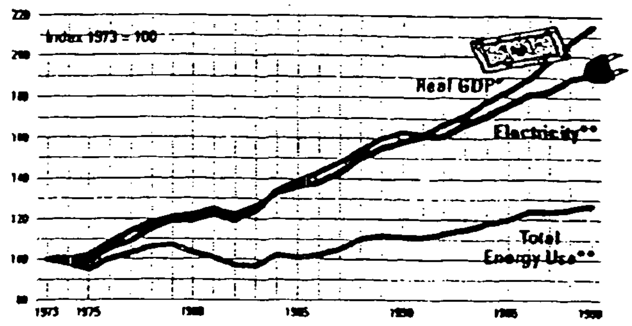
Fuel Diversity is Needed in the Generation of Electricity

- A diverse fuel mix helps to protect companies and consumers from contingencies such as fuel unavailability, price fluctuations, and changes in regulatory practices. It also helps ensure stability and reliability in electricity supply. Our reliance upon abundant, North American sources of energy to generate electricity strengthens national security.

- The use of electricity has grown dramatically in the last 50 years and mirrors the equally robust growth of the gross domestic product (GDP), the nation's gauge of economic health. While the overall intensity of energy use has decreased by more than 40 percent since 1960, the intensity of electricity use in the U.S. economy (measured by electricity consumption per dollar of real GDP) has increased by more than 25 percent over the same time period. Today, electricity powers industrial machines, tools, computers, and appliances. Its versatility is unparalleled, and its substitutes are few, if any.

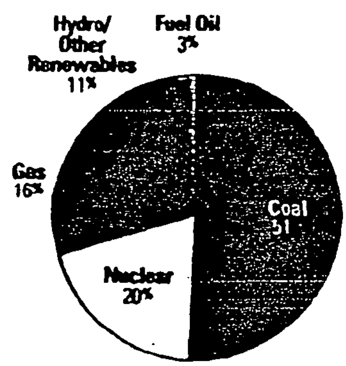
Our Nation's Economic Growth Is Closely Linked to Electricity.



*Source: U.S. Dept. of Commerce, Bureau of Economic Analysis **Source: Energy Information Administration

- Low-cost, reliable electricity results, in part, from our ability to utilize a variety of readily available energy resources—coal, nuclear energy, natural gas, hydropower and, to a lesser extent, other renewable resources (solar, wind, geothermal, and biomass), and fuel oil. The variety of fuels used to generate electricity depicts diversity. Fuel diversity is also reflected in the fact that certain fuels are more readily available in certain regions of the country—hydropower in the Pacific Northwest, natural gas in the Southwest, and coal in the Midwest, for example.

- Energy production and efficient energy consumption are important for economic prosperity. As such, regulatory policies must be created and implemented with an eye toward their effect on the electricity sector and the health of the economy as a whole. Otherwise, efforts devised with little, or no, consideration for the impact upon electricity and economic growth will have the unintended consequence of limiting the flexibility and diversity of fuels that have led to low-cost electricity.



Current Generation Mix

(Numbers exceed 100% due to rounding.)
Source: Form EIA-759 and Form EIA-860B

- The conflicts arising between regulatory policies and the activities needed to ensure the continued availability of low-cost electricity can be addressed in a manner that minimizes the unintended consequences on energy production and use. Other national priorities — such as environmental protection, public health, and the proper stewardship and conservation of our nation's lands and finite resources — can be met through the use of market-based mechanisms, technological innovation, and the coordination of multiple, crosscutting regulatory requirements.

continued

diversity in brief

Enact a National Energy Program Based on Fuel Diversity

Maintaining a diversity of supply options is key to affordable and reliable electricity. Policymakers and regulators should work together to reconcile conflicting energy, environmental, or other public policy goals. They should promote initiatives that capitalize on all of our nation's abundant natural resources. They should address challenges that limit the development and viability of fuel sources. Finally, they should implement a national energy program that:

- Maximizes the diversity of fuels and technology options available for the generation of electricity.
- Examines a comprehensive approach to the implementation of environmental regulations in order to reduce compliance costs and regulatory uncertainty.
- Promotes the development of technologies to improve energy efficiency, to enhance energy conservation, and to increase the environmental performance of fuels in the generation mix.
- Places an emphasis on market-based approaches (e.g., trading programs or results-based approaches), rather than on specific technology or prevention processes, to achieve important environmental or other societal goals.
- Removes barriers to siting electric generating stations, transmission lines, and gas pipelines.
- Revamps the process for licensing and relicensing hydropower facilities.
- Focuses the nation's tax policy on bringing new and advanced energy technologies, including electricity generation technologies, to the marketplace.
- Establishes clearly defined decision making processes that will ensure the timely resolution of conflicting policies among various government agencies.

Now more than ever, a sound energy policy that promotes stability, affordability, and reliability of electricity requires a diversity of fuels and technology options and the adoption of policies that better achieve low-cost electricity supplies, attainment of environmental goals, and economic prosperity.

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Piecemeal Agenda

- **NO_x**

- NSR enforcement initiative
- $PM_{2.5}$ NAAQS
- 8-hour ozone NAAQS
- Regional haze
- Section 126 petitions (8-hour ozone NAAQS)
- Air quality related values
- NOx NAAQS revision
- NOx TMDL
- Waxman-type bills
- Future NAAQS revisions

Piecemeal Agenda

- **Mercury**
  - EPA rulemaking
  - Hg TMDL
  - Urban air toxics program
  - Waxman-type bills
  - State programs
- **CO_2**
  - Kyoto Protocol
  - Rio Agreement
  - Waxman-type bills
  - CAA regulation of CO_2

Piecemeal Agenda

- **New Source Review**
- Restrictive policy
- Lawsuits

Piecemeal Agenda

- SO_2

- NSR enforcement initiative
- PM2.5 NAAQS
- Regional Haze
- Section 126 petitions (PM2.5 NAAQS)
- Air quality related values
- Short-term SO2 NAAQS
- Waxman-type bills
- Future NAAQS revisions

Fuel Mix for IOU's
Source: RDI PowerData Database run 2/09/01

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Holding Company Name	Nameplate Capacity MW	FUEL	PERCENT OF TOTAL
Allegheny Energy, Inc.	3,416.76	COAL	80.3%
Allegheny Energy, Inc.	840.24	HYDRO	19.7%
Allegheny Energy, Inc.	**4,257.00**	**TOTAL**	**100.0%**
American Electric Power Co., Inc.	26,363.77	COAL	67.8%
American Electric Power Co., Inc.	8,624.86	GAS	22.2%
American Electric Power Co., Inc.	836.78	HYDRO	2.2%
American Electric Power Co., Inc.	2,967.88	NUCLEAR	7.6%
American Electric Power Co., Inc.	59.39	OIL	0.2%
American Electric Power Co., Inc.	6.60	WIND	0.0%
American Electric Power Co., Inc.	**38,859.28**	**TOTAL**	**100.0%**
Cinergy Corp.	10,213.34	COAL	86.0%
Cinergy Corp.	1,045.10	GAS	8.8%
Cinergy Corp.	64.80	HYDRO	0.5%
Cinergy Corp.	555.93	OIL	4.7%
Cinergy Corp.	**11,879.17**	**TOTAL**	**100.0%**
DTE Energy Co. (Detroit Edison Co.)	7,709.38	COAL	59.5%
DTE Energy Co. (Detroit Edison Co.)	1,486.95	GAS	11.5%
DTE Energy Co. (Detroit Edison Co.)	969.60	HYDRO	7.5%
DTE Energy Co. (Detroit Edison Co.)	1,166.00	NUCLEAR	9.0%
DTE Energy Co. (Detroit Edison Co.)	1,531.65	OIL	11.8%
DTE Energy Co. (Detroit Edison Co.)	91.07	WASTE	0.7%
DTE Energy Co. (Detroit Edison Co.)	**12,954.65**	**TOTAL**	**100.0%**
PSC of New Mexico	1,040.58	COAL	63.3%
PSC of New Mexico	154.00	GAS	9.4%
PSC of New Mexico	429.39	NUCLEAR	26.1%
PSC of New Mexico	20.00	OIL	1.2%
PSC of New Mexico	**1,643.97**	**TOTAL**	**100.0%**

204

FUEL MIX FOR PSEG UNREGULATED SIDE

Public Service Enterprise Group, Inc.

	MW	PERCENT
COAL	2,161	18.2%
GAS	4,404	37.0%
HYDRO	211	1.8%
NUCLEAR	3,087	26.0%
OIL	2,030	17.1%
TOTAL	11,893	100.0%

States served and Number of Ultimate Customers
by Utility (1999 data)

AEP

Number of Ultimate Customers: 4,799,542
States served:
Arkansas
Indiana
Kentucky
Louisiana
Michigan
Ohio
Oklahoma
Tennessee
Texas
Virginia
West Virginia

Cinergy

Number of Ultimate Customers: 1,450,680
States served:
Indiana
Kentucky
Ohio

Scurce: EEI Catalogue of Investor-Owned Electric Utilities and the EIA-861.

DTE (Detroit Edison)

Number of Ultimate Customers: 2,078,607
States served:
Michigan

Public Service Company of New Mexico

Number of Ultimate Customers: 361,384
States served:
New Mexico

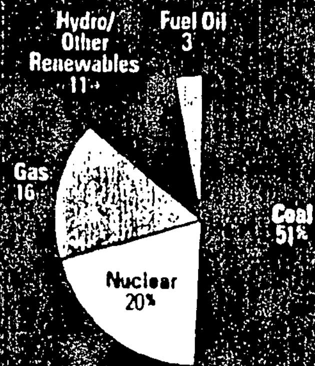
Allegheny Energy		Public Service Enterprsie Group (P
Number of Ultimate Customers:	1,414,264	**Number of Ultimate Customers:**
States served:		**States served:**
Maryland		New Jersey
Ohio		
Pennsylvania		
Virginia		
West Virginia		

'SE&G)

1,991,609

diversity

a historical perspective



Current Generation Mix

(Numbers exceed 100% due to rounding.)
Source: Form EIA-759 and Form EIA-860B

Electricity suppliers use a variety of fuel sources to generate electricity. The combination of energy sources used is referred to as the "generation mix". Our nation's current generation mix is illustrated in the chart at right.

Using a varied generation mix protects electricity producers and their customers from contingencies such as supply shortages, fuel price fluctuations, and changes in regulatory practices. The generation mix also is key to affordable and reliable electricity for our nation. In planning the type of facility to build for electricity generation, companies must consider the cost and availability of fuel sources.

The generation mix has shifted dramatically over the past 20 years. Changes in legislative and regulatory practices, often prompted by national energy crises, have produced many of these shifts. Access to fuel sources on public lands, tax policies, technology improvements, and environmental requirements also have shaped the cost and availability of fuels for electricity generation.

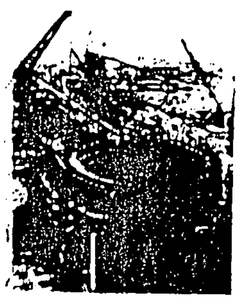
This timeline provides examples of the many forces that have influenced our nation's energy policies since 1950. The past fifty years have seen recurring events and numerous policy re-directions. History clearly demonstrates the need for a comprehensive, consistent, and coordinated energy policy in the U.S. — an energy policy that preserves the electric generation mix. Policymakers are called upon to develop policies that foresee, rather than react to, trends.

shaping fuel diversity

energy and environmental policy trends 1950-2001

153 The first practical nuclear reactor is put into service – for a submarine. It is only a matter of time before nuclear energy is approved for electricity generation.

1954 The Atomic Energy Act allows private ownership of nuclear reactors, paving the way for nuclear power plants to be built.



1957 The Price Anderson Act sets limits to plant liability for damage to the public, and thereby promotes nuclear development.

1961 The first gas turbines are placed into service as stationary power sources by U.S. utilities, opening the door to another fuel source for the nation's energy supply.

1963 Jersey Central Power and Light Company announces its commitment for Oyster Creek nuclear power plant, the first time a nuclear plant is ordered as an economic alternative to a fossil fuel-fired plant. This action opens the door to a vast resource for electricity generation.

1963–1967 A series of limited federal air pollution control laws are passed, introducing regulatory controls aimed at utility plants.

1970 The Environmental Protection Agency is created, forming the first federal government entity dedicated entirely to regulating and enforcing environmental laws.

1970 The Clean Air Act is enacted, setting more stringent air pollution standards. It establishes new primary and secondary standards for ambient air quality, sets new limits on emissions from stationary and mobile sources to be enforced by both state and federal governments, and increases funds for air pollution research.

1973 The price of oil soars as an Arab oil embargo begins, precipitating enactment of a variety of federal laws on energy security and efficiency. The embargo also results in increased demand for alternate energy sources, particularly nuclear energy.

1973 The Emergency Petroleum Allocation Act imposes controls on crude oil and petroleum products.

1973 Utilities order 41 nuclear power plants, a one-year record and a move encouraged by the U.S. government. Few of the plants are actually built.

1975 Thirteen nuclear projects are cancelled due to increased costs and decreased electricity demand. Many state agencies that regulate electricity rates do not favor the building of these plants.

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197… The Public Utility Regulatory Policies Act (PURPA) is enacted, requiring utilities to buy power from qualifying non-utility generating facilities that use renewable energy sources or cogeneration. PURPA also facilitates the increased use of natural gas and encourages development of renewables.

1978 The Natural Gas Policy Act decontrols the price of most gas drilled after 1977 and leaves controls on "old gas" found before then. Price controls on the old gas and all remaining gas were phased out by 1993 by the Natural Gas Wellhead Decontrol Act of 1989.

1978 The Energy Tax Act encourages conversion of boilers to coal, as well as investment in cogeneration equipment and solar, wind, geothermal, and other renewable energy technologies.

1978 The Powerplant and Industrial Fuel Use Act (repealed in 1987) prohibits new utility plants and industrial boilers from burning oil or gas and requires existing plants to phase out use of those fuels by 1990. (Gas phase-out was dropped in 1981.)

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1979 A major accident occurs at Unit 2 of the Three Mile Island nuclear plant near Harrisburg, Pennsylvania. No new nuclear plants are ordered or built after this accident.

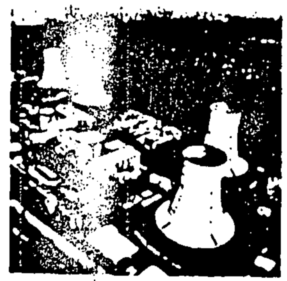
1979 Oil prices jump, this time due to an Iranian revolution, resulting in pressure to reduce oil use for power generation.

1980 The first U.S. wind farm is built in New Hampshire.

1980 The U.S. Synthetic Fuels Corporation Act is created to encourage development and production of synthetic fuels (repealed in 1986).

1982 The Nuclear Waste Policy Act directs DOE to build a geological repository for high-level nuclear waste. The ban on reprocessing nuclear fuel is lifted.

1986 The Electric Consumers Protection Act contains the first significant amendments to the hydro-licensing provisions of the Federal Power Act, a 1935 law giving the Federal Energy Regulatory Commission (FERC) broad authority over interstate transmission and sale of wholesale electricity.



1990 Clean Air Act amendments mandate additional pollution controls that set limits on the amount of a pollutant in the air anywhere in the U.S. All states must develop state implementation plans (SIPs) to explain how they will achieve the limits set forth in the Clean Air Act.

1990–1991 Iraq invades Kuwait, an oil-rich nation, an action that results in higher oil prices. Operation Desert Storm is launched by the U.S. and the U.N. to force Iraq's withdrawal from Kuwait.

1992 The Energy Policy Act is enacted to address a broad array of energy-related issues.

1993 Commercial production of variable speed wind turbines begins in the U.S. By 2000, wind power is established as a reliable source of renewable energy. Worldwide, it is one of the fastest growing sources of electricity production (on a percentage basis).

1997 DOE unveils its "million solar roofs" initiative in a federally funded attempt to encourage renewable energy use in every day applications.

1998 President Clinton signs the Kyoto Protocol, which would obligate the U.S. to a 7 percent greenhouse gas emissions reduction target below 1990 levels. If the U.S. Senate were to ratify the Protocol, the U.S. generation mix is projected to be altered significantly.

1999 The DOE unveils "Wind Powering America," an initiative to support the growth and development of wind power in the U.S.

1999 The EPA sues seven shareholder-owned, coal-based utilities and the Tennessee Valley Authority, alleging violations of the New Source Review Program under the Clean Air Act and putting further pressure on coal-based generators.

1999 Edwards Dam in Maine is breached (torn down), marking an effort to reduce the number of dams used to generate electricity. The relicensing of hydroelectric facilities is one mechanism being utilized to reduce the use of hydropower. Between 1999 and 2010, 228 hydropower projects face relicensing.

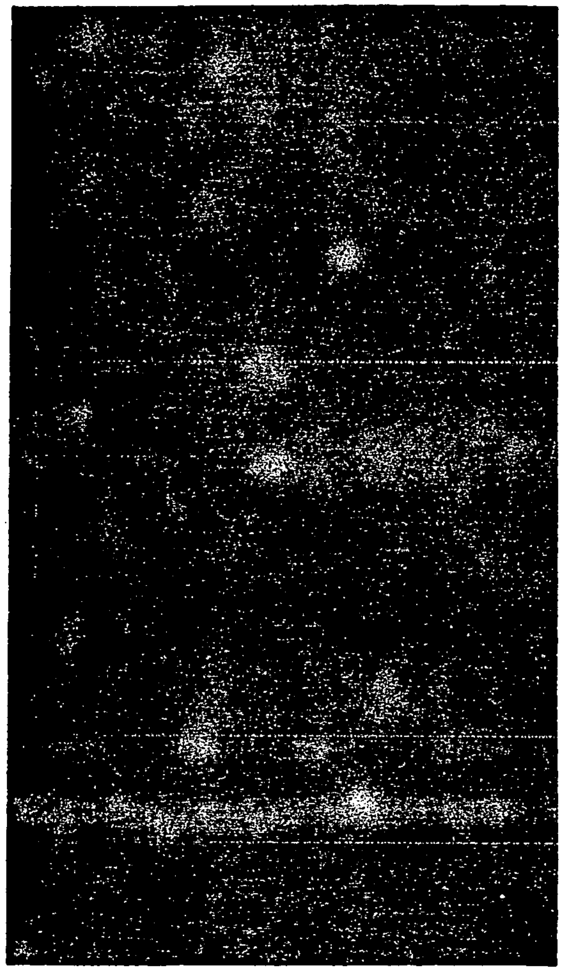
2000 The Nuclear Regulatory Commission approves the first renewals, for 20-year periods, of nuclear power plant operating licenses. Calvert Cliffs in Maryland becomes the first to be relicensed.

2000 A federal appeals court upholds EPA's NO_x SIP call rule in 19 of the 22 states covered by the regulation, maintaining pressure on coal-based generators to further decrease nitrogen oxide (NO_x) emissions from coal-based power plants.

2001 Natural gas prices continue to reach historic highs, contributing to spikes in electricity and home heating costs.

'78 '79 1980 '81 '82 '83 '84 '85 '86 '87 '88 '89 1990 '91 '92 '93 '94 '95 '96 '97 '98 '99 2000 '01

207



New Power For The Next Century

A HARVEST OF TECHNOLO

GAS TURBINE MODULAR HELIUM REACTOR

GENERAL 582

DOE002-0593

'Steam still generates most of the world's electricity. We burn coal, gas and oil, and use nuclear power to turn water into steam to drive turbines which produce electricity. Even larger quantities of gas and imported oil are being consumed for other energy requirements including transportation. Burning fossil fuels can be very expensive and taxing to the environment. Oil accounts for over half of our entire balance of payments deficit. . . ***more than a billion dollars a week in foreign oil imports***. . . up the chimney, out the tailpipe and into our atmosphere.

B A C K G R O U N D

There is a cleaner, more economical, and much safer way to generate electricity. The Gas Turbine - Modular Helium Reactor (GT-MHR) is a new turbine generating system powered by a passively-safe nuclear reactor. It eliminates the need to make steam to produce electricity, and frees us from the pollution and waste of fossil-fuel generating plants. It could also help to reduce our billion dollar a week deficit for foreign oil.

THE FUTURE

By capitalizing on late 20th century technologies, the GT-MHR achieves high efficiency with a compact operating system and elegant simplicity. The gas turbine power cycle is far superior to the century-old steam plant technology employed in all other nuclear plant designs. The super-safe GT-MHR power plant includes one or more modular units in underground silos, each containing a reactor vessel and a power production vessel.

WHY IT WORKS

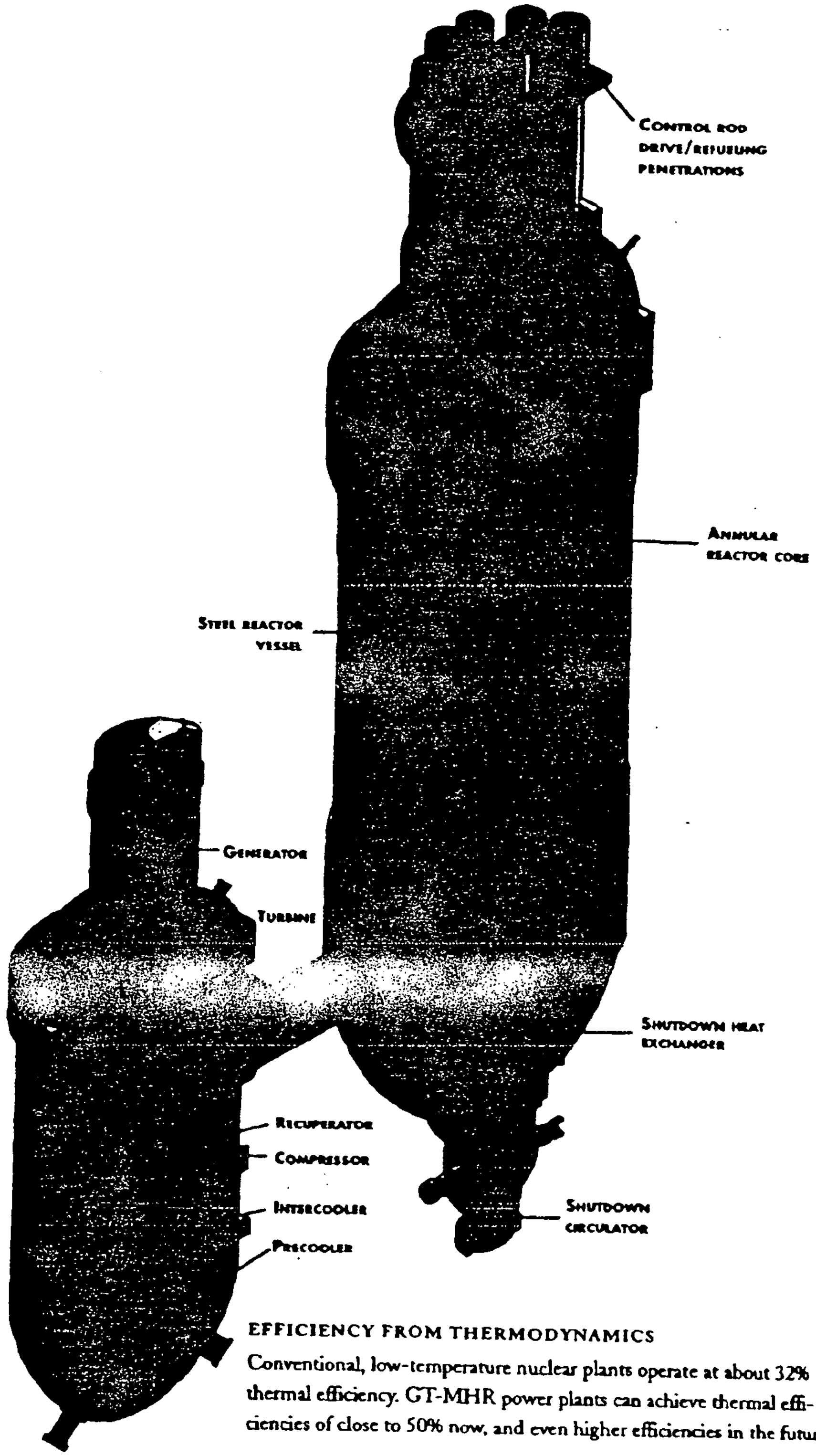
Because helium is naturally inert and single-phase, the helium-cooled reactor can operate at much higher temperatures than today's conventional nuclear plants. The higher the turbine's operating temperature, the more efficient the plant becomes. . . mandated by the laws of thermodynamics. To this is added the efficiency of the helium directly driving the turbine, instead of having to go through a large heat exchanger to produce steam.

DESIGN SIMPLICITY

The combination of the MHR and the gas turbine represents the ultimate in simplicity, safety and economy. The reactor coolant directly drives the turbine which turns the generator. This allows costly and failure prone steam generating equipment to be eliminated.

- *No* corrosion-caused leaks
- *No* corrosion-caused reduction in operating life
- *No* stress corrosion-caused structural failures

The GT-MHR combines a meltdown-proof reactor and advanced gas turbine technology in a power plant with a quantum improvement in thermal efficiency. . . approaching 50%. This efficiency makes possible much lower power costs, without the environmental degradation and resource depletion of burning fossil fuels.



EFFICIENCY FROM THERMODYNAMICS

Conventional, low-temperature nuclear plants operate at about 32% thermal efficiency. GT-MHR power plants can achieve thermal efficiencies of close to 50% now, and even higher efficiencies in the future.

- 50% more electrical power from the same number of fissions.
- Dramatically lower high-level radioactive waste per unit of energy – today's reactors produce 50% more high-level waste than will the GT-MHR.
- Much less thermal discharge to the environment. Plants can use air cooling.

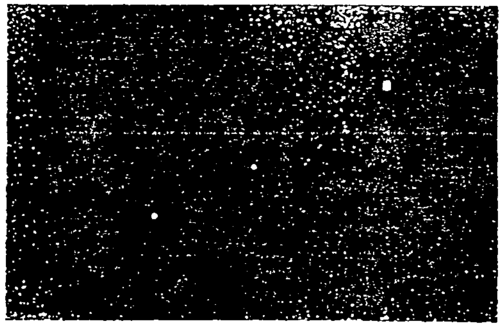
THE SIMPLICITY OF THE GAS TURBINE AND THE HELIUM REACTOR PROVIDE THE NEXT GREAT STEP IN NUCLEAR POWER

PLANT DESCRIPTION

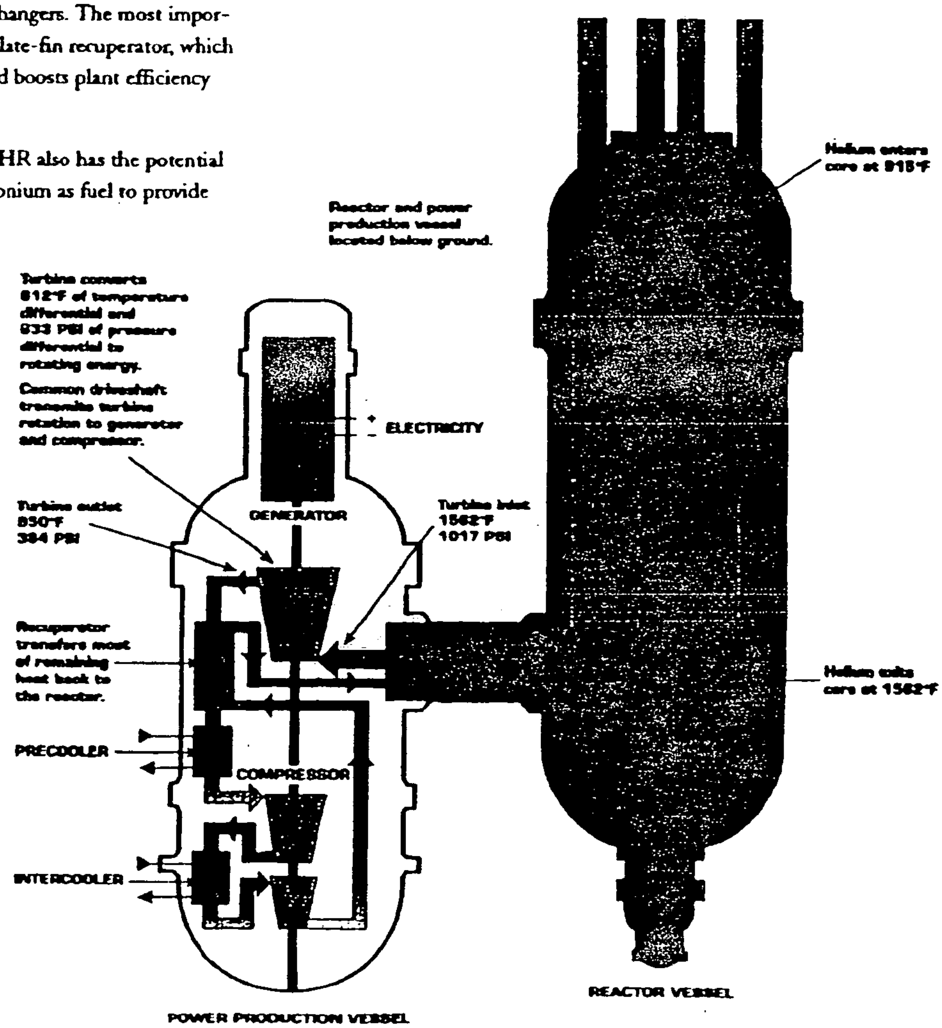
The entire GT-MHR power plant is essentially contained in two interconnected pressure vessels enclosed within a below-ground concrete containment structure. The larger vessel contains the reactor system and is based on the steam-cycle MHR which has been under development as part of the U.S. Department of Energy's Modular High Temperature Gas-cooled Reactor program.

The second, smaller vessel contains the entire power conversion system. The turbo-machine consists of a generator, turbine and two compressor sections mounted on a single shaft rotating on magnetic bearings. The active magnetic bearings control shaft stability while eliminating the need for lubricants within the primary system. The vessel also contains three compact heat exchangers. The most important of these is a 95% effective plate-fin recuperator, which recovers turbine exhaust heat and boosts plant efficiency from 34% to 48%.

As an added benefit, the GT-MHR also has the potential to consume weapons-grade plutonium as fuel to provide electrical energy.



HIGH TEMPERATURES MEAN HIGH THERMAL EFFICIENCY.



SCHEMATIC FLOW DIAGRAM

HIGH EFFICIENCY AND PLANT SIMPLICITY PRODUCE LOW-COST ELECTRICITY AND MINIMIZE WASTE

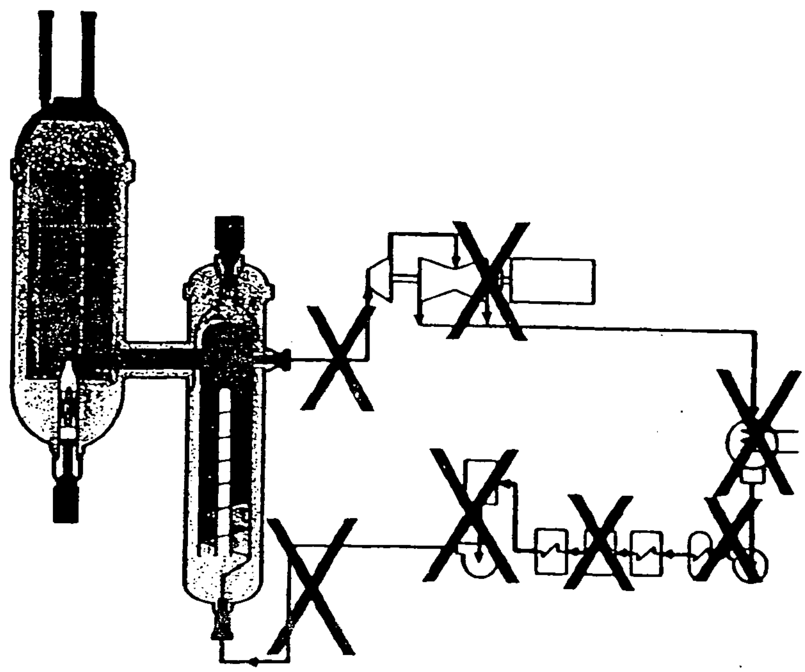
ECONOMICS

- Dramatic system simplification combined with high efficiency results in impressively low power costs, even competing with those of natural gas-fired, combined-cycle systems.
- Fewer systems and fewer parts significantly reduce the complexities of conventional reactor systems.
- Modularized, factory-controlled, serial production ensures industrial-type economy based on established learning curves, rather than elusive economies of scale.
- Simple systems based on passive and inherent safety characteristics and slow transient responses mean simpler licensing and reduced staffing needs.

CONSERVATION

The GT-MHR technology can help reduce fossil-fuel usage four ways:

- Nuclear-generated electricity saves fossil fuels.
- High temperature characteristics make the MHR ideal for supplying high-grade thermal energy for oil and gas-intensive industrial processes.
- Waste heat is at the ideal temperature for use in district heating.
- Inexpensive electricity can be used to charge electric vehicles, further saving gas and oil. Ultimately, the MHR's high temperature capability will make hydrogen and methanol economically attractive for transportation uses.



SYSTEMS THAT ARE ELIMINATED BY GT-MHR

THE ENVIRONMENT

- The GT-MHR is free of the emissions associated with burning fossil fuels.
- Radioactive emissions from helium-cooled reactor plants are lower than those from comparably sized coal-fired plants.
- The MHR spent fuel characteristics result in substantially reduced proliferation risks.
- Worker radiation doses are only a fraction of those from today's nuclear power plants.
- MHR thermal discharge to the environment is low, due to the system's high efficiency.

THE ROBUST, CERAMIC FUEL RETAINS ITS INTEGRITY EVEN UNDER THE MOST SEVERE ACCIDENT CONDITIONS AND SIMPLIFIES THE SAFETY EQUATION

A SIMPLER, MORE RATIONAL WAY TO THINK ABOUT NUCLEAR SAFETY: FOUR LEVELS OF SAFETY*

Level 0:

No hazardous materials or confined energy sources.

Level 1:

No need for active systems in event of subsystem failure.
Immune to major structural failure and operator error.

Level 2:

No need for active systems in event of subsystem failure.
No immunity to major structural failure or operator error.

Level 3:

Positive response required to subsystem malfunction or operator error.
Defense in depth. No immunity to major structural failure.

The MHR is the only reactor that meets the criterion of Level 1 safety. Its design is derived from natural properties of materials and optimum choice of reactor size, geometry and power density. It can withstand the total loss of coolant without the possibility of a meltdown – going beyond simply saying "it is safe enough."

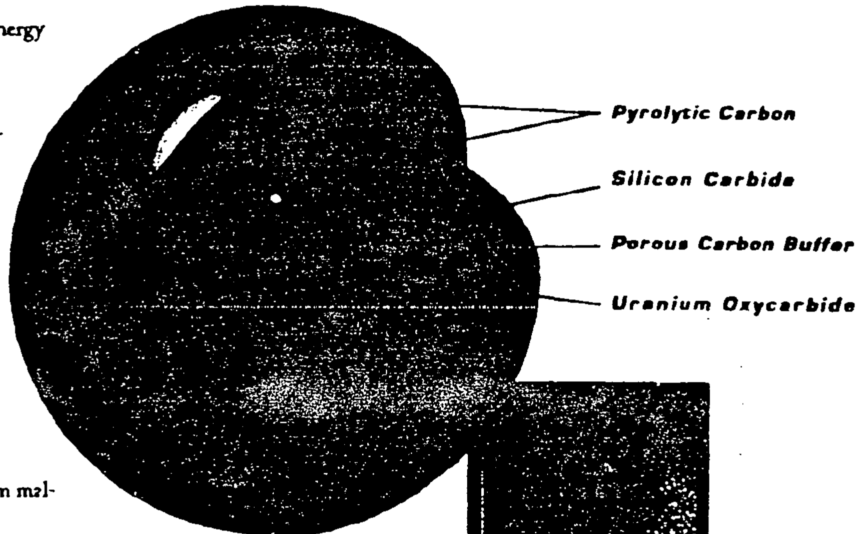
The Chernobyl and Three Mile Island reactors fall in the Level 3 category.

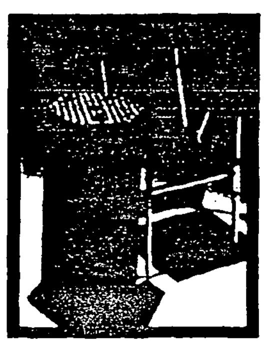
The Chernobyl power runaway was initiated by human error which resulted in loss of coolant, which led to structural failure.

The Three Mile Island core melt accident was caused by human error which resulted in loss of coolant. Core melt caused radioactivity release from the reactor vessel, but containment effectively confined radioactive release.

*Definition developed by Professor Lawrence Lidsky, Massachusetts Institute of Technology.

MULTIPLE LAYERS OF TOUGH, HIGH TEMPERATURE TOLERANT PYROLYTIC CARBON AND SILICON CARBIDE CONFINE THE RADIOACTIVE FISSION PRODUCTS AT THEIR SOURCE, IN THE CENTER OF THE FUEL PARTICLE.





COATED FUEL PARTICLES (TOP) ARE FORMED INTO FUEL RODS (RIGHT) AND INSERTED INTO GRAPHITE FUEL ELEMENTS (LEFT).

The MHR is the onl

WHAT A LARGE NEGATIVE TEMPERATURE COEFFICIENT MEANS TO SAFETY

The picture has captured a power pulse in a TRIGA research reactor where the power increased 4,000 times over its normal operating range. This intentional power increase lasted only about one hundredth of a second because the reactor has a very large negative temperature coefficient which naturally shuts the reactor down. . . guaranteed by the laws of nature.

Like other U.S. power reactors, the GT-MHR has a negative temperature coefficient.

By contrast, Chernobyl had a positive reactivity coefficient; its temperature increase acted to intensify the fission reaction, thus causing a runaway.

SAFETY: THE EFFECTS OF DECAY HEAT

Decay heat, resulting from the decay of fission products, is a phenomenon in all reactors. The heating does not stop when the power is shut off, so having a negative temperature coefficient is good but not enough.

The decay heat at Three Mile Island caused the reactor fuel to melt, even after the fission reaction had essentially stopped, because of the loss of cooling water.

The Modular Helium Reactor's decay heat will not cause a meltdown even if the coolant is lost. The reactor's low power density and geometry assure that decay heat will be dissipated passively by conduction and radiation without ever reaching a temperature that can threaten the integrity of the ceramically-coated fuel particles. . . even under the most severe accident conditions.

reactor that meets the criterion of Level 1 safety.

THE TURBOMACHINERY AND HEAT EXCHANGER TECHNOLOGIES REQUIRED FOR THE GT-MHR HAVE ALREADY BEEN DEVELOPED BY INDUSTRY

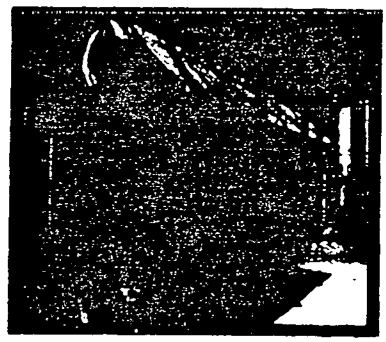
AIRCRAFT INDUSTRY EXPERIENCE

The MHR gas turbine uses the same technology as the modern jet engine. However, in the case of the MHR, its design requirements are less demanding. Temperatures, stresses and blade tip speeds are all far below those proven in millions of hours of aircraft engine operation. Although most of the components represent current state-of-the-art technology, additional design work is needed to integrate them into the most economical and reliable package. Supercomputers will aid in analyzing the dynamics of the gas turbine power-producing module before the prototype hardware is built. This design approach is very similar to that which went into the Boeing 747-400... which had to work the first time.

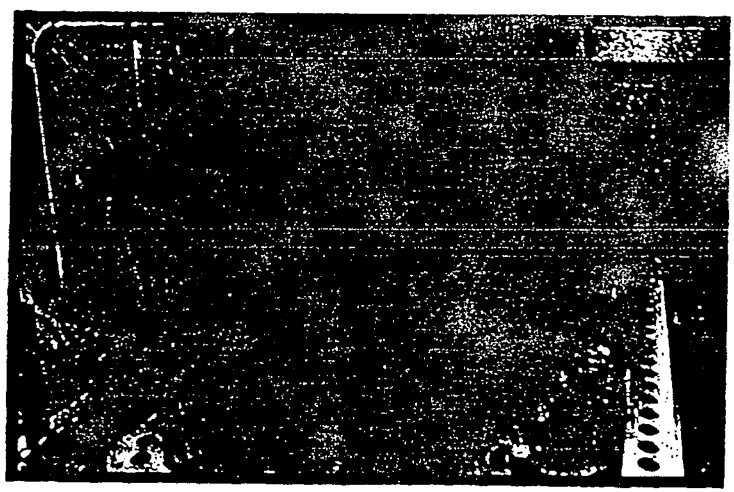
Even more intriguing, the gas turbine uses the same technology which powers the 747... the modern jet engine. Just as it replaced the reciprocating engine for modern world-spanning travel, so will the gas turbine replace the steam turbine to generate electricity.

RECUPERATOR EXPERIENCE

New plate-fin recuperators are highly efficient and compact heat exchangers. The GT-MHR recuperators will draw on extensive experience from the fossil-fuel power industry, including the construction of sixty such units for large gas turbine plants.



RECUPERATOR



LARGE HELIUM TURBINE

DOE002-0600

OVER 30 YEARS OF EXPERIENCE PROVIDE AN EXTENSIVE DATA BASE

England - Dragon - 1964 to 1976 — This helium-cooled test reactor provided early successful demonstration of the high temperature gas-cooled reactor.

Germany - AVR - 1966 to 1988 — This prototype helium reactor operated successfully for over 20 years and provided demonstration of 1740° F gas outlet temperature and key safety features, including safe shutdown with total loss of coolant circulation and without control rod insertion.

U.S. - Peach Bottom - 1967 to 1974 — This prototype helium reactor achieved a remarkable 86% availability during the electricity production phase.

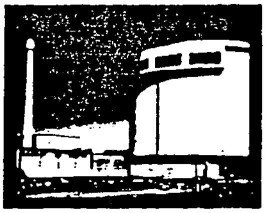
U.S. - Fort St. Vrain - 1979 to 1989 — This reactor used water-lubricated circulator bearings which resulted in frequent water ingress into the reactor system and caused significant down time. In spite of a poor operating record, the Fort St. Vrain coated fuel and reactor core worked extremely well. Because of the non-corrosive nature of helium, workers were exposed to radiation doses only about 1% that of average water reactors. Fort St. Vrain generated about 5 billion kWh.

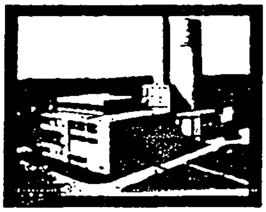
Germany - Oberhausen 2 - 1975 to 1987 — This 50 MW electric turbine plant represented the evolutionary step from fossil-fired gas turbines with air as the working fluid towards the realization of nuclear powered helium gas turbines. Helium was used as the working fluid in a closed-cycle process for electricity and heat production. The plant incorporated heat exchangers (recuperator, precooler, intercooler) of comparable size to those required for a 600 MW thermal GT-MHR.

Germany - THTR - 1985 to 1988 — This helium-cooled nuclear power plant generated about 3 billion kWh. Political resistance in the post-Chernobyl era precipitated early shutdown.

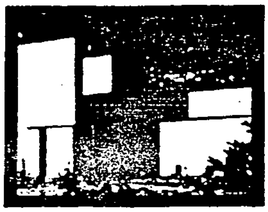
Russia — Various successful demonstrations of fuel fabrication and fuel irradiation performance.

Japan — A high temperature helium-cooled test reactor is now under construction.


Dragon


AVR


Peach Bottom


Fort St. Vrain


Oberhausen


THTR

DOE002-0601

INDUSTRY EXPERTS BELIEVE THE TECHNOLOGY REQUIRED HAS ALREADY BEEN DEVELOPED

Now. . . a timely convergence of four state-of-the-art technologies offers quantum improvements in power generation efficiency and cost.

1. The **helium-cooled reactor** in modules of up to 600 thermal megawatts matches the size of the newest gas turbines, while maintaining the inherent safety characteristics demonstrated in the steam-cycle helium-cooled reactor.

"A unique characteristic of the helium-cooled reactor is its high gas temperature which enables efficient electricity generation directly from a gas turbine generator in the reactor system. This eliminates the need for complex, costly and inefficient steam cycle equipment and results in the most efficient and economic reactor ever. The meltdown-proof modular helium reactor takes full advantage of over 30 years and billions of dollars of gas reactor design and development."

MARK FORSSELL, SENIOR VICE PRESIDENT (HELIUM REACTORS), GENERAL ATOMICS

2. **Gas turbines** using fossil fuels achieve high efficiencies in aircraft and in electric power generating stations. Higher operating temperatures and continually improving reliability have produced high efficiency and low power cost. This technology is directly translatable to a nuclear heat source with helium as the coolant.

3. **Magnetic bearings** are proving superior in diverse applications, including natural gas pipeline pumping stations. Magnetic bearings are essentially frictionless and provide longer equipment life.

"The GT-MHR turbomachinery is a logical application of our successful jet engine and power turbine technology. Sizes are similar, and stresses, temperatures and pressures are either less demanding or comparable to those in our latest civil transport engines. Helium is an excellent working fluid. Being inert, helium eliminates concern over oxidation and corrosion. Its properties provide subsonic flow fields throughout the machine and eliminate the complexities of transonic and supersonic flows in the blading.

The GT-MHR magnetic bearings are a modest extension of existing in-service technology. They are essentially frictionless, and provide automatic and adjustable dynamic dampening and on-line monitoring resulting in improved performance and reliability. Of particular importance is the elimination of oil-lubricated bearings and the potential ingress of oil into the working fluid.

All things considered, we think the GT-MHR is a highly rational, practicable and economic approach to the next generation of nuclear power plants."

T.A. DONOHUE, GENERAL MANAGER, ADVANCED TECHNOLOGY OPERATIONS, GENERAL ELECTRIC

4. Compact **plate-fin recuperators** developed for fossil-fired applications are capable of achieving 95% effectiveness.

"The recuperators for the GT-MHR are about the same size as units we have made for the fossil fuel power industry. In fact, we have made some 2 ½ million units using this type of construction, sixty of which have been for large gas turbine plants. These sixty units utilize approximately 1,000 individual brazed modules. GT-MHR temperatures are less demanding than units now in operation, and efficiencies are within the range of units previously delivered. Pressures are higher, but we do not see that as a problem. The non-corrosive helium environment is very beneficial."

DR. J. A. FRIEDERICY, DIRECTOR, RESEARCH & TECHNOLOGY, ALLIEDSIGNAL AEROSPACE

THE WALL STREET JOURNAL THURSDAY, AUGUST 17, 1989

Nuclear Reactors Everyone Will Love

By PAUL E. GRAY

The American nuclear industry is its own worst enemy. By trying to push ahead with vast, costly projects that have been stalled by political opposition, it exacerbates the irrational public fears that have blocked the development of nuclear power in the U.S. Instead, utilities should be exploring a new type of nuclear reactor that recent technological innovation has put within reach: a reactor type that is environmentally sound and economically competitive.

This reactor type uses new fuels, new design methods to dissipate heat, and smaller units that can be built and tested off-site. It has excited scientists and engineers world-wide, but industry and government leaders in this country–pessimistic about the public's willingness to accept nuclear power under any circumstances–are reluctant to adopt it here. That reluctance is wrong. It is time for all of us to take a hard look at modular reactors.

It has become a commonplace to say that the nuclear industry in the U.S., is dead, and that its death looks like a suicide. The problems of Seabrook and Shoreham nuclear plants are persuasive demonstrations of that commonplace.

Oil Spills and Garbage

But oil spills, undisposable garbage, polluted beaches, and–above all–steadily increasing atmospheric pollution from fossil fuel are persuading many political leaders to review their prejudices about nuclear energy. Americans who want a clean, safe and domestically produced energy source should follow–especially because all the practical alternatives to nuclear power present grave hazards to public safety and health. The perceived risks of nuclear power are grossly overestimated and usually stated without reference to the hazards of other energy sources.

There are, however, two major problems with the present generation of water-cooled reactors. The light-water reactors, or LWRs as they are known to engineers, used in nearly all the plants in operation or under construction in the United States, place heavy demands on their builders and operators. The risk they pose to public safety is an accident involving loss of coolant that could lead to the melting of fuel elements and the subsequent release of radioactivity. The safety systems for these light-water reactors are extremely complicated. These safety systems require explicit anticipation of all possible forms of failure and they must necessarily rely on probability analysis. In a world in which probability is not widely understood, such analysis is not reassuring to most of the public. While these methods lead to margins of safety that are quite acceptable, Americans remain, for the most part, skeptics.

The second problem is that light-water reactors, which are custom-made at the site, cannot be tested in advance to ascertain what would happen in a true disaster.

It is possible, however, to design and build a series of small reactors that could produce the power of a large plant. These reactors could survive the failure of components without fuel damage and without releasing radioactivity because their fuels can withstand the maximum temperatures possible under the worst of circumstances. Their design limits the power density of the reactor core as well as the actual size of the core, and exploits natural processes to remove heat and avert fuel damage in the event of a loss of coolant.

Such "passively safe" reactors can be designed to suffer the simultaneous failure of all control and cooling systems without danger to the public. And their safety can be demonstrated by an actual test: a West German modular reactor has passed such tests three times.

It is possible to design and build reactors that could survive the failure of components without fuel damage and without releasing radioactivity.

One of the most advanced of these modular reactors is under study at the Massachusetts Institute of Technology. It is based on the West German reactor that has demonstrated its safety, but adds several technologies in which the U.S. still has a competitive industrial edge. The hot gas that leaves the reactor is used directly to spin a turbine (based on aerospace designs), which, in turn, drives a small, very high speed generator (based on power electronics). This combination results in a power generating system that is substantially smaller and more efficient than current LWR systems, which are based on steam turbines and low-speed generators.

By virtue of its inherent or passive safety features, this small, gas-cooled reactor eliminates the complex, active safety systems needed by current LWRs. The gas turbine eliminates the complex, hard-to-maintain, steam generators common both to nuclear plants and ordinary fossil-fired power plants. The result is a power plant that produces electricity not only at lower cost than nuclear reactors (an easy target), but that is competitive with the projected cost of next-generation "clean" coal-fired plants. Power from such coal generators, the Department of Energy calculated in 1986, would cost an average of 5.5 cents per kilowatt hour. Power from modular reactors can be brought to market for 4.5 cents per kilowatt hour.

These savings can be realized because the new plants will be made to a single, prelicensed design in central factories. Construction costs are estimated to be less than $1,000 per kilowatt of electricity. Costs per kwe for the Seabrook reactor in New Hampshire and the Shoreham project in Long Island were more like $5,000 to $6,000, primarily because of long delays and extensive redesign during construction. Operating costs of traditional nuclear plants are also much higher than those of modular plants would be, because the older type require very large staffs–700 people per plant–to oversee their involuted safety systems. Modular reactors could offer much more safety with staffs only half as big.

These new plants will not only be much cheaper to build, but the added bonus of high efficiency means there will be less heat to throw away. The plants will be easier to site because they cause less damage to the local environment. And, best of all, they will not do harm to the atmosphere.

These new reactors do not eliminate the waste disposal problem, but their ceramic encapsulated fuel does simplify it. A fuel that can survive unscathed in a reactor core during an accident is obviously securely packaged for disposal under more benign conditions (albeit at the cost of a significant increase in waste volume). Many of the problems associated with the high temperature achieved by the fuel of the current generation reactors are eliminated and the potential for burial in deep geological sites is enhanced. This same feature also makes it much more difficult for the discharged fuel to be processed to produce unauthorized nuclear weapons.

Nil Operating Risk

Smaller, modular reactors will produce less energy than present reactors do: 100 to 150 megawatts of electrical power output compared with 1,000 to 1,500 megawatts, but this difficulty can be overcome, if necessary, by linking together a number of small, individual power-producing modules. Since each module would be identical and centrally built, licensing could be standardized and based on full-scale testing of an actual plant. This is an enormous advantage. It would allow actual demonstration of the reactors' response to severe and demanding hazards.

With an operating risk that is virtually nil and the production of significantly less radioactivity in the environment than coal-fired electric power plants, second-generation nuclear power could be a major source of environmentally sound energy if we would only take advantage of it. The failure of the government and the nuclear industry to provide leadership in developing a second generation of power plants based on these developments has already cost us dearly.

Mr. Gray is president of the Massachusetts Institute of Technology

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DOE002-0603

US Needs Fresh Approach to Nuclear Energy

By Edward Teller

THE nuclear-power industry in the United States is currently in a hiatus. The primary reason for this is rooted in the industry itself. The nuclear industry has had the technical capability to make reactors that can't melt down. But it has not done so.

Why has the nuclear industry *not* pushed more vigorously in the direction of the low power density technology that makes this possible? Mostly because of the lack of public and institutional support, and the huge existing investment in first-generation reactor technology. There has also been concern that the cost of meltdown-proof safety characteristics could not be justified.

These factors have made the industry and the government reluctant to pursue quantum improvements in reactor designs. As a result, the world is struggling with acceptance of 30-year-old technology and, at the same time, proceeding along two dangerous paths: excess reliance on Middle East oil and on currently inexpensive natural gas.

Like all energy sources throughout history, first-generation nuclear reactors have had problems. The most obvious are those of Three Mile Island and Chernobyl. There are also the problems of cost and schedule caused by systems that are too big, too complicated, and too onerous. High operating costs, aggravated by spiraling regulatory requirements and the need for premature replacement of major systems, such as steam generators, have undermined public confidence and nuclear power's competitiveness. Finally, there are concerns about radioactive wastes with half-lives of thousands of years and nuclear proliferation questions.

In the face of this history and many justifiable concerns, some people have suggested we should simply abandon nuclear power. I believe it would be shortsighted and foolish to do so.

With the best second-generation reactor design we have the ability to address virtually all of the concerns about nuclear power. In meltdown-proof reactors, the power density is low and the reactor size is such that there is not enough heat available to fail – even during an accident involving complete loss of coolant. The tiny high temperature-tolerant ceramic fuel particles encapsulate and contain the products of fission. In case of an unplanned increase of temperature, the reactor shuts itself down.

Siting the reactors underground enhances security and containment features. These factors also effectively eliminate the risk to the public from potential sabotage, terrorist activity, or even overt military attack. Modularizing the reactors and building them in factories with factory cost- and quality-controls makes their cost and schedules predictable and minimal.

The leading work on one such design, helium reactor technology, is currently being done by General Atomics of San Diego. The first work on the technology began in Russia in 1949 and substantial advances were made in Germany through the '60s, '70s, and '80s.

Improvements of this kind should help the public acceptance of nuclear reactors. Indeed, they are needed to offset the consumption and emissions of millions of barrels of imported oil and billions of cubic feet of natural gas.

There is another reason why the world cannot turn its back on nuclear power. Hundreds of tons of uranium and plutonium exist in weapons and they are becoming surplus. The arms agreements, calling for the destruction of tens of thousands of nuclear weapons, create this situation, and an incredible opportunity.

First-generation reactors have had problems. The best second-generation designs can address virtually all of the concerns about nuclear power.

The opportunity is to destroy uranium and plutonium from the weapons while providing much-needed electricity. The best way to destroy this plutonium is to burn (fission) it in new, safe meltdown-proof reactors.

Some people advocate putting the plutonium in glass logs and burying it. While this is a relatively inexpensive way of dealing with the plutonium, it is insufficient because it only gets the plutonium out of sight. It does not destroy it. We should not be happy with any plan in Russia that leaves plutonium where it can be dug up and reconstituted into weapons. Likewise, the Russians should not be satisfied with a plan that does not destroy US plutonium.

And no one should be satisfied with any plan that does not take advantage of the huge energy potential of the plutonium, which can be captured even as the plutonium is destroyed for all time.

This destruction should not rely on constant reprocessing. It should be destroyed as totally as possible in one cycle. This is the most decisive way of dealing with surplus plutonium. If it is not dealt with in such a manner, this material can fall into the wrong hands.

Growing world-energy requirements, particularly in the third world, must also be dealt with, lest the third world be relegated to consuming huge amounts of irreplaceable fossil fuels, ripping down its forests, or fighting for resources that are fundamental to civilized progress.

In my opinion the best alternative, the key to accomplishing these essential synergistic objectives, is completing the development of a truly modern, inherently safe reactor. I believe the public would look differently at reactors that could not melt down – compared to present reactors, which cannot be without their coolant for more than a few seconds or minutes. I believe the public would prefer reactors that are sited underground and are less subject to terrorists and seismic events.

I believe the public would like to see reactors for the future that are built substantially in factories with factory cost- and quality-control. Such reactors would be more economical than and can ultimately replace present reactors, which use 50 percent more nuclear fuel resources, create 50 percent more waste, and exhaust 100 percent more thermal energy to the environment.

The nuclear-power industry has made great contributions worldwide to reduced reliance on Middle East oil and reduced toxic emissions to the environment. The public must be brought to appreciate this and recognize the importance of energy to productivity and improved living standards.

Even the Club of Rome now believes the world is headed for serious energy problems because of its reliance on fossil fuels. I believe we must rally our intellectual and technical resources and deliver the best nuclear power possible to ease this problem.

The nuclear industry's current fixation on reactors that represent the technical status quo, and the Department of Energy's lack of support of research and development of inherently safe meltdown-free reactors is unworthy of the great American tradition of creating a better future through progress in technology.

■ *Edward Teller is a senior research fellow at the Hoover Institution in Stanford, Calif.*

January 31, 1994

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Fueling Electricity Growth for a Growing Economy

David Harrison, Jr., Ph.D.

Todd Schatzki, Ph.D.

National Economic Research Associates

Prepared for Edison Electric Institute

January 2001

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DOE002-0605

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701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
www.eei.org

January 2001

597

DOE002-0607

Published by:
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Phone: 202-508-5000
Web site: www.eei.org
Publications orders: 1-800-EEI-5453

Fueling Electricity Growth for a Growing Economy

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Acknowledgments

This study was requested and funded by Edison Electric Institute to provide information on the future of electric power generation and the many factors that might affect electricity fuel use, costs, and rates over the next two decades. The study was conducted by National Economic Research Associates, Inc. (NERA), an international firm of more than 300 consulting economists with nine offices in the United States and three offices abroad that specializes in the application of economics to complex issues of business and public policy. NERA has extensive experience in energy and environmental regulation and policy.

Dr. David Harrison and Dr. Todd Schatzki authored the study. Ms. Erica Altman, Mr. Justin Murphy, Mr. Daniel Radov, and Mr. Harsha Thirumurthy assisted the authors. Mrs. Paula Blumsack prepared the document. Many individuals at the Edison Electric Institute and their member companies provided data and background information. NERA is grateful to all of these individuals and organizations. Responsibility for the report, however, and for any errors or omissions, rests solely with NERA.

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David Harrison, Jr., is a Senior Vice President of National Economic Research Associates, Inc. (NERA) in its Cambridge, Massachusetts, office and director of NERA's environmental economics practice. Before joining NERA, Dr. Harrison was an Associate Professor at the John F. Kennedy School of Government at Harvard University, where he taught microeconomics, energy and environmental policy, and other subjects for more than a decade. He earlier served as Senior Staff Economist on the President's Council of Economic Advisors, where his areas of responsibility included energy and environmental regulation. At NERA, Dr. Harrison has directed numerous studies related to energy and environmental issues. These studies include analyses of individual environmental regulations, climate change policy, the use of emissions trading, and other innovative policy approaches. He has served as a consultant in these and other areas to numerous public and private organizations. Dr. Harrison is the author or co-author of four books and monographs, as well as many articles in professional journals. He received a Ph.D. in Economics from Harvard University, an MS in Economics from the London School of Economics, and a BA in Economics from Harvard College.

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Executive Summary

The U.S. electric power industry faces major changes over the next two decades. Initiatives to restructure the industry and provide greater competition are proceeding both at the federal and state levels. Because they can affect all aspects of companies' provisions of electricity and other energy services to their customers, these competitive initiatives pose both challenges and opportunities for the industry. At the same time, electricity and other energy suppliers face the prospect of a large number of environmental and energy policy initiatives. The most prominent initiatives relate to concerns about air emissions and global climate change, but the initiatives involve many other areas such as cooling water intake, waste disposal, relicensing of nuclear and hydro plants, energy facility siting, and drilling constraints.

These various public policy initiatives could have substantial effects on electricity costs and prices as well as on the fuels and technologies used to produce electricity. The net effects of all of these initiatives, however, are difficult to predict. Studies tend to focus on one initiative at a time. There have been a few recent reports that integrate assessments of air quality and climate change policies,[1] but even these studies do not account for the potential impacts of the many non-air initiatives.

A. Objective of This Report

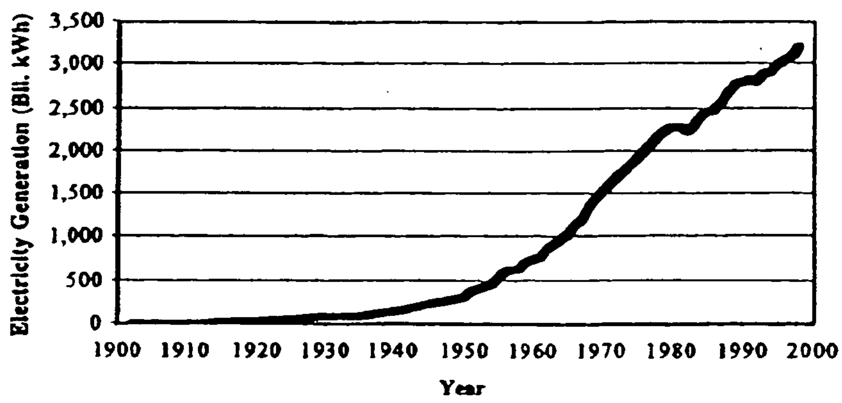
The major objective of this report is to provide information on the large number of potential polices that might affect electricity generation over the next two decades. The report fills an information gap because, to our knowledge, no single report considers the full range of potential policies that might affect the electricity generation sector. There are, however, many useful studies of individual initiatives. Indeed, the major contribution of this report is that it amasses all the information already developed on these various policy initiatives into a single document. To provide a context for these potential changes, the report also provides a brief overview of the history of electricity generation and fuel use.

B. Historical Information on U.S. Electricity Generation and Fuel Use

Electricity generation grew substantially in the twentieth century, as can be seen in Figure ES-1. The dramatic growth in electricity use reflects electricity's increasing usefulness

1 Prominent recent integrated studies have been performed by the Electric Power Research Institute (EPRI 2000) and the U.S. Environmental Protection Agency (U.S. Environmental Protection Agency 1999a). Both of these studies assess the potential effects of climate change and air quality policies.

Figure ES-1. U.S. Electricity Generation Growth in the Twentieth Century

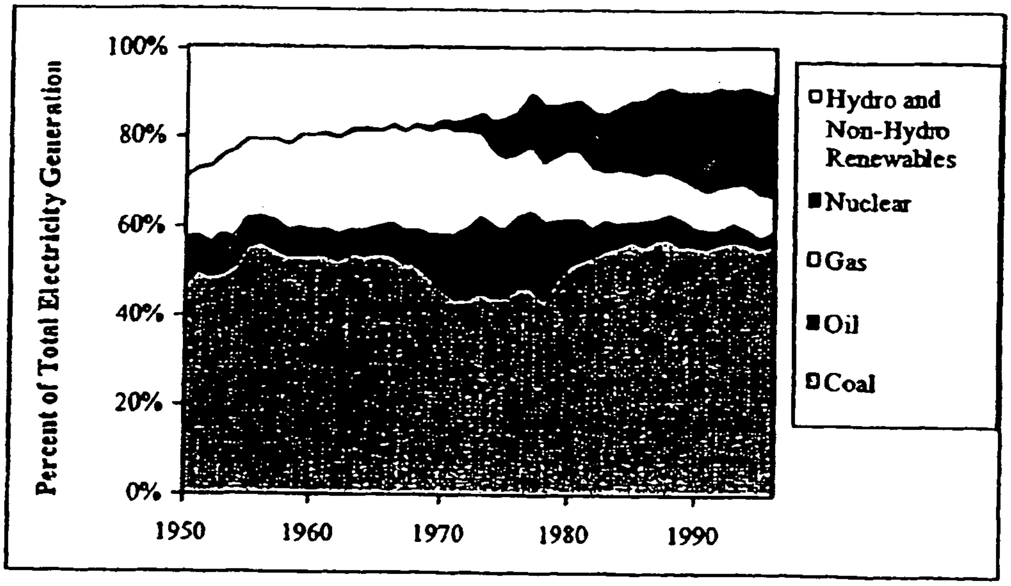


Source: U.S. Bureau of the Census 1975, U.S. Bureau of the Census 1999.

to households as well as its rising importance in industrial and commercial processes. Indeed, as many studies indicate, growth in electricity use and reduced electricity prices have contributed substantially to overall growth in the United States economy. (See, e.g., National Research Council 1986, Dennison 1985.)

Electricity has been generated by a broad range of fuels that have provided cheap and reliable power. The electricity generation mix includes coal and nuclear units that provide baseload power—that is, power that can be supplied throughout the year at low cost—as well as oil or gas powered units and hydroelectric facilities that provide power in peak periods. This peak power is more expensive on a cost per kilowatt-hour basis but can be called on at short notice to provide the added power needed on very cold or hot days when demand is greatest. Figure ES-2 shows the electric fuel mix in the U.S. over the last half-century. Approximately 50 percent of generation has been fueled by coal, with nuclear, gas, hydro, oil, and non-hydro renewable sources accounting for the other 50 percent of fuel use. This mix has been quite stable over approximately the last 50 years, with nuclear comprising an increasing share and oil a decreasing share in the last two decades.

Figure ES-2. Electric Generation Fuel Mix over Approximately the Last Half-Century



Fuel mix represents the percent of electric generation (in MWh) for each fuel type.
Source: U.S. Bureau of the Census 1975, U.S. Bureau of the Census 1999.

C. Impact of Policy and Regulatory Initiatives over the Next Two Decades

Future regulatory and policy initiatives would influence the electricity generation fuel and technology mix and would affect electricity costs and the overall economy.

1. Impact on Electricity Generation Fuel Use

Table ES-1 lists the types of energy and environmental policy initiatives reviewed in this report (detailed policies are listed in Chapter III) and rough indications of their potential impacts on use of the various electric generation fuels/technologies. A positive sign (+) indicates that the initiative would positively affect the use of a given fuel, while a negative sign (–) indicates a negative impact. The number of signs (ranging from one to three) indicates the potential importance of the policy to the particular fuel. No entry is provided when a fuel is not affected or the impacts are generally similar for all fuels.

These rough impact assessments suggest that most fuels would be subject to both positive and negative influences under these regulatory initiatives. The overall impacts on each fuel type can be summarized as follows:

Table ES-1. Potential Qualitative Impacts of Regulatory Policies on Electricity Generation Fuels in the Next Two Decades

	Coal	*Natural Gas*	*Nuclear*	*Hydro*	*Non-Hydro Renewables*
AIR QUALITY					
NO_x	– –				
SO_2	– –				
Mercury	– –				
CLIMATE CHANGE	– – –	+ +	+	+	+ +
WATER QUALITY					
Effluent Guidelines	–				
Cooling Water	–		–		
WASTE DISPOSAL					
Solid/Hazardous	–				
Nuclear			– –		
ENERGY POLICIES					
Hydro Relicensing				–	
Nuclear Relicensing			–		
Renewables Policy					+ +
Siting Generating Plants	–	–	– –	–	–
Siting Natural Gas Pipelines		–			
Drilling Constraints		–			

A minus sign (–) indicates that the policy would negatively affect the use of the given fuel for electric power within the next two decades. A plus sign (+) indicates that the policy would positively affect the use of the given fuel for electric power within the next two decades. The number of signs provides a qualitative indication of the potential magnitude of the impact of alternative policies. Oil is not included as a fuel because it is projected to account for less than 1 percent of the fuel mix.

1. *Coal*—While coal's low cost and abundance could increase its utilization, current regulatory initiatives generally would decrease coal utilization. The most significant initiatives are the policies for air emissions and climate change.
2. *Natural gas*—Natural gas currently is the fuel of choice for new electricity generation and is favored by many regulatory initiatives. Several policies may, however, limit the rate of natural gas expansion (pipeline siting and drilling constraints) and the long-term availability of reserves (drilling constraints).
3. *Nuclear*—Some regulatory initiatives (particularly climate change policy) could significantly increase nuclear utilization, while others such as relicensing, and the

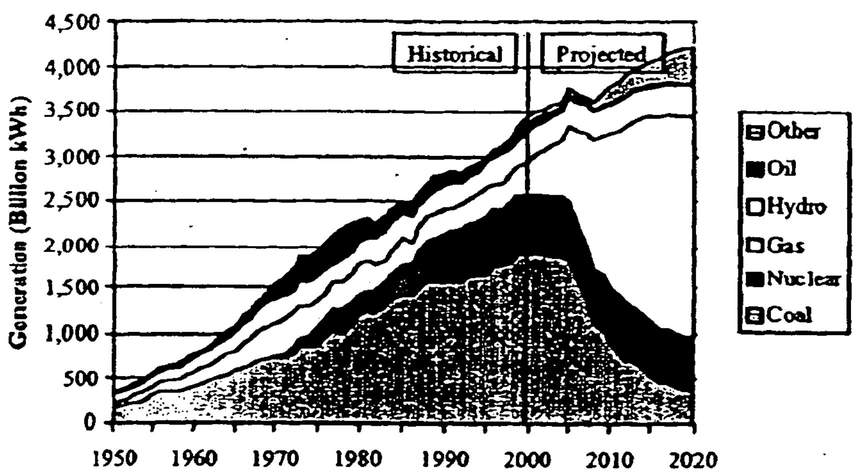
unresolved issue of nuclear waste disposal might reduce the generating capacity available from nuclear.

4. *Hydroelectric*—Due to low variable costs, hydroelectric units are anticipated to run at full capacity. However, hydroelectric relicensing may impose operating conditions or constraints that reduce generation capacity and limit the periods over which the units can operate.

5. *Non-hydro renewables*—Non-hydro renewables are expected to experience some continued growth and a stable share of the fuel mix under electric power restructuring. Several regulatory initiatives could increase utilization of non-hydro renewables. These include climate change policies and policies directly targeting non-hydro renewables.

These qualitative results can be supplemented with quantitative results for some of the initiatives. Figure ES-3 shows the Electric Power Research Institute's (EPRI's) recent estimates of the fuel mix impacts of three major regulatory programs (the Kyoto Protocol for CO_2, the NO_X SIP Call, and a 50 percent reduction in electric utility SO_2 targets from the Title IV level). As noted by EPRI, the impacts of Kyoto are particularly sensitive to assumptions regarding the role of international carbon trading; the EPRI projections assume that Annex I trading and non-carbon greenhouse gas changes shift the U.S. domestic Kyoto target for CO_2 from 7 percent below the 1990 level to 9 percent above the 1990 level.

Figure ES-3. Impact of Regulatory Policies on U.S. Electric Generation Fuel Mix



Fuels in the figure are shown in the same order as the list. Projected impacts are based upon a domestic Kyoto target of 9 percent above 1990 levels (Annex I trading case), the NO_X SIP Call, and a 50 percent reduction in electric sector SO_2 emissions from Title IV limits.

Source: Historical from U.S. Bureau of Census 1975, U.S. Bureau of Census 1999. Projected from Electric Power Research Institute 2000.

These results indicate the potential for large changes in the mix of fuels used for electricity generation over the next two decades. Compared to the "business-as-usual" scenario in 2020, coal would go from about 50 percent to around 10 percent, natural gas would go from about 30 percent to approximately 60 percent, and renewables would go from about 10 percent to approximately 20 percent (Electric Power Research Institute 2000).

2. *Impact on Electricity Generation Costs and Rates*

These various policy initiatives could have substantial effects on the overall cost and price of electricity. No comprehensive assessments are available for all of the initiatives, although this report summarizes results for the individual policies.

Climate change is projected to have by far the largest impact on electricity rates. The Kyoto Protocol with Annex I trading is projected to increase 2020 electric rates by about $30 per megawatt-hour (in 1999 dollars), which is almost a 45 percent increase over current prices. (The impact would be almost twice as great with no international carbon trading and about one-third as great under complete international carbon trading.)

3. *Other Impacts*

The cumulative impacts of these regulatory initiatives could extend to the economy as a whole. The various studies reviewed in this report predict that electricity price increases and other costs could adversely affect the U.S. economy, leading to short-term increases in inflation and decreases in the rate of overall economic growth. Abrupt changes also could create substantial regional declines in employment in energy-producing areas.

In addition to these cumulative impacts, the piecemeal nature of the policy initiatives could lead to conflicts. As noted in the recent EPRI report, some of the capital costs incurred may turn out to be unproductive because of the different timing of the various policies. In particular, the capital equipment installed to comply with additional NO_X and SO_2 constraints required in 2003 and 2007 may be scrapped if the plants were retired to comply with CO_2 requirements assumed to begin in the 2008–12 period.

The potential inconsistency of air quality and climate change requirements is an example of a more general issue of inconsistency among these various potential policies. Indeed, some predicted changes for a given initiative may not be achievable if other policy initiatives are undertaken. Constraints on siting of gas pipeline or drilling of natural gas, for example, could limit the feasible increase in natural gas use, at least within the next two decades. Thus, the extensive shift to gas-fired generation predicted under climate change policies may conflict with other policies that are carried out at the same time. These possibilities reflect the disadvantages of a piecemeal approach to energy and environmental policy that does not take into account interactions among policy initiatives.

D. Implications

The fact that the regulatory initiatives summarized in this report could affect electricity generation fuels and technology—as well as electricity costs, rates, and the overall economy—does not mean that the initiatives should not be pursued. These results, however, do suggest three implications.

First, the potential interactions among this large number of regulatory and policy initiatives suggest the usefulness of taking a broad look at electricity generation and the factors that influence its future. A piecemeal approach to regulatory policy seems ill suited to this situation.

Second, the substantial costs and impacts of these policies suggest the importance of detailed policy analyses that would consider the costs and benefits of policy alternatives. It would be particularly useful to develop means of achieving policy objectives that avoid excessive costs and major dislocations of the energy and electric power systems.

Third, the potential for expensive scrapping of control equipment before the end of its useful life suggests the importance of considering the appropriate timing and not just the desirable levels of regulatory requirements. It would be useful to consider whether temporal flexibility could be provided to electricity generators that would reduce the overall costs while maintaining important environmental and energy policy objectives. Greater flexibility in timing also would provide the time to develop lower emitting and less expensive technologies that reduce the costs and overall impacts of achieving desirable policy objectives.

Part I ✦ Introduction

Electricity use in the United States has grown dramatically in the twentieth century. This dramatic growth reflects electricity's usefulness to households as well as its importance in industrial and commercial processes. The availability and low cost of electric power have been major contributors to the expansive growth of the American economy in this century. Electricity allows factories to be organized in ways that greatly enhance manufacturing productivity and thereby the overall productivity of the economy. Electricity available for office uses—including the increasingly large number of computer and other information-processing tasks—contributes to growth in non-manufacturing sectors as well.

Electricity use promises to increase in the next two decades as the economy expands and as electricity rates are reduced in response to increased competition, particularly in electricity generation. Federal and state efforts to restructure the electricity sector will tend to encourage the retention and development of low-cost generation sources. At the same time, electricity generation planners must adjust to the possibility of a large number of environmental and energy policy initiatives. Although the most prominent initiatives relate to climate change and air pollution concerns, there are many other areas of concern, ranging from waste disposal to cooling water intake regulations, relicensing policies, and energy facility siting constraints.

A. Objectives of the Report

The overall purpose of this report is to provide background for discussion of potential public policies related to the electric power sector. The background provided in this report consists of two elements:

1. Historical information on electric power generation.
2. Implications of prospective environmental and energy initiatives for the U.S. fuel mix, electricity prices, overall costs, and economic impacts.

The second element—the descriptions of potential regulatory policies and their fuel use and other implications—constitutes the bulk of this report. This emphasis is an attempt to fill a gap in the literature. Although many studies describe individual regulatory proposals, we are not aware of any study that considers the full range of potential policies that might affect the electricity generation sector.[2] Indeed, the major contribution of this report is to present all the information that has been developed on these various policy initiatives in a single document.

2 Noteworthy partial exceptions are recent studies by the Electric Power Research Institute (EPRI 2000) and the U.S. Environmental Protection Agency (U.S. Environmental Protection Agency 1999a). Both of these studies assess the potential effects of climate change and air quality policies. Even these studies, however, do not include the effects of other environmental regulations, such as water or hazardous waste regulations.

It is important to point out that this report does not provide all of the information needed to assess public policies in these various areas. For any specific policy initiative, it would be necessary to evaluate the costs, benefits, and other impacts of the various alternatives. But, the information presented in this report suggests that an exclusive focus on one initiative may overlook important interactions among the various policies. It is important to consider the full range of policies, their timing, and their interactions.

B. Organization of the Report

The report is organized as follows. Chapter II provides a brief history of the electric sector and the fuels that have been used for power generation. The chapter also summarizes the competitive initiatives facing the industry. This chapter is relatively brief because these issues have been dealt with in many previous reports.

Chapter III constitutes the bulk of the report. This chapter provides information on the large number of regulatory and policy initiatives that could affect the fuel mix for electricity generation in the next two decades. The objective is not to evaluate the merits of these various regulatory initiatives, but rather to summarize each initiative and to report the information that has been developed on each initiative's likely effects on electricity fuel use, electricity prices, and other economic impacts.

Chapter IV provides a summary of the impacts of the various initiatives and some discussion of their implications. These implications include the usefulness of considering interactions among the initiatives and of developing policy approaches that encourage flexible and cost-effective results.

Part II ✦ Background of U.S. Electricity Demand, Electricity Fuel Use, and Economic Growth

This chapter provides historical background on electricity demand, fuel use, and the role that electricity has played in U.S. economic growth.

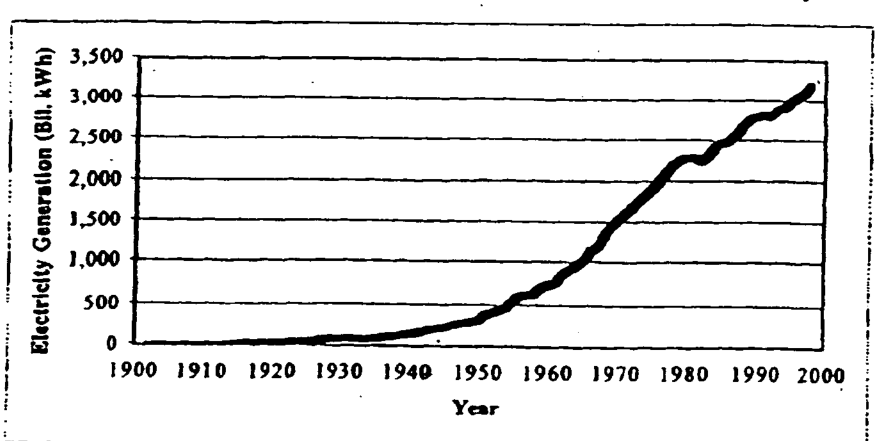
A. Growth in U.S. Electricity Demand

Figure 1 shows the enormous increase in U.S. electricity generation over the last century. This increase reflects growth in the U.S. population as well as changes in per capita electricity use. Figure 2 shows that per capita electricity use in the U.S. has risen substantially over this period. The dramatic growth in electricity use reflects electricity's usefulness to households in operating an increasing number of electric appliances as well as electricity's importance in industrial and commercial processes.

As many commentators have long noted (e.g., Schurr et al. 1979, Schurr 1990), low electricity prices and reliable supplies are two major factors that have contributed to the large growth in the U.S. economy in the twentieth century. Electrification allowed processes within a factory to be arranged in a way that would have been impossible in an earlier era when factories were powered by prime movers, with shafts and belts carrying mechanical power to the various operations. Electrification allowed new arrangements that greatly enhanced manufacturing productivity and productivity of the entire economy.

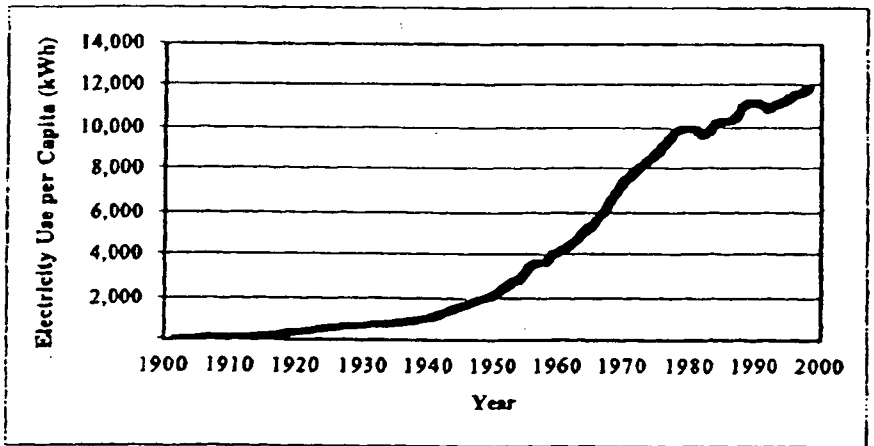
Electricity continues to contribute to economic growth through its role in the "information" economy. The U.S. economy is increasingly dependent upon computer- and

Figure 1. U.S. Electricity Generation Growth in the Twentieth Century



Source: U.S. Bureau of the Census 1975, U.S. Bureau of the Census 1999.

Figure 2. U.S. Electricity Use per Capita in the Twentieth Century



Source: U.S. Bureau of the Census 1975, U.S. Bureau of the Census 1999.

information-processing capabilities. The electronic equipment behind these capabilities requires electricity. The advancements in information technology have led to fundamental changes in offices and other functions that are essential to non-manufacturing sectors. It is these sectors, served by electricity, that are projected to account for much of the future economic growth in the United States.

Several studies have quantified the effects of lower electricity prices on U.S. economic performance. The National Research Council evaluated the effects of electricity prices on the productivity of the economy, measured as output per unit of input.[3] The study concluded that lower electricity prices led to increased productivity in 23 of the 35 industries that were studied (National Research Council 1986).[4] Similar results about the importance of electric generation to economic growth have been reported in other studies (e.g., Denison 1985; Schurr 1990).

B. U.S. Electricity Fuel Use

The hallmark of the U.S. electricity sector has been a broad range of fuels and technologies used in the generation of electric power, coupled with an efficient transmission and distribution system for bringing electricity to the places where it is used. This diversified fuel mix generally includes coal and nuclear units that provide baseload power—that is, power that can be supplied throughout the year at low cost—as well as oil- or gas-powered

3 Input includes labor, capital, electricity, non-electrical energy, and materials.

4 The study also found that lower prices for non-electrical energy increased productivity in 28 of the 35 industries studied (National Research Council 1986).

units and hydroelectric facilities that provide power in the peak periods. This peak power is more expensive on a cost per kilowatt-hour basis, but can be called upon at short notice to provide the added power needed on very cold or hot days when demand is greatest.

Figure 3 shows the fuel mix for the U.S. electric power sector. Coal is the largest source, accounting for 51 percent of overall electricity produced. Nuclear units account for the second largest at 20 percent. This is followed by natural gas, 16 percent, and hydropower and other renewable technologies (e.g., wind and solar), 11 percent. Oil-fired plants account for the remaining 3 percent of overall electricity production.

Figure 4 shows the long-term trends in the fuel mix. Over the last half century, coal's share of generation has fluctuated between 45 and 58 percent. Nuclear has increased its share substantially in the last two decades, largely at the expense of oil-fired generation.

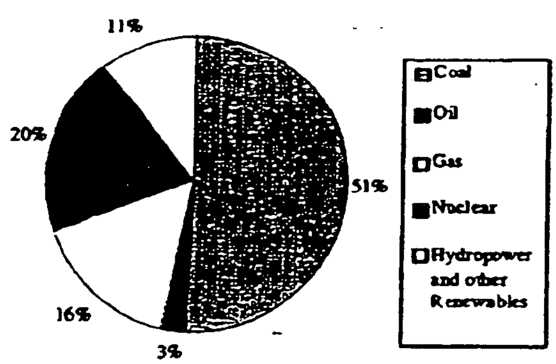
C. Projected Electricity Fuel Use under Competition

This section provides background information on electric power restructuring and competition initiatives and their potential impact on future electricity generation.

1. Restructuring and Competition

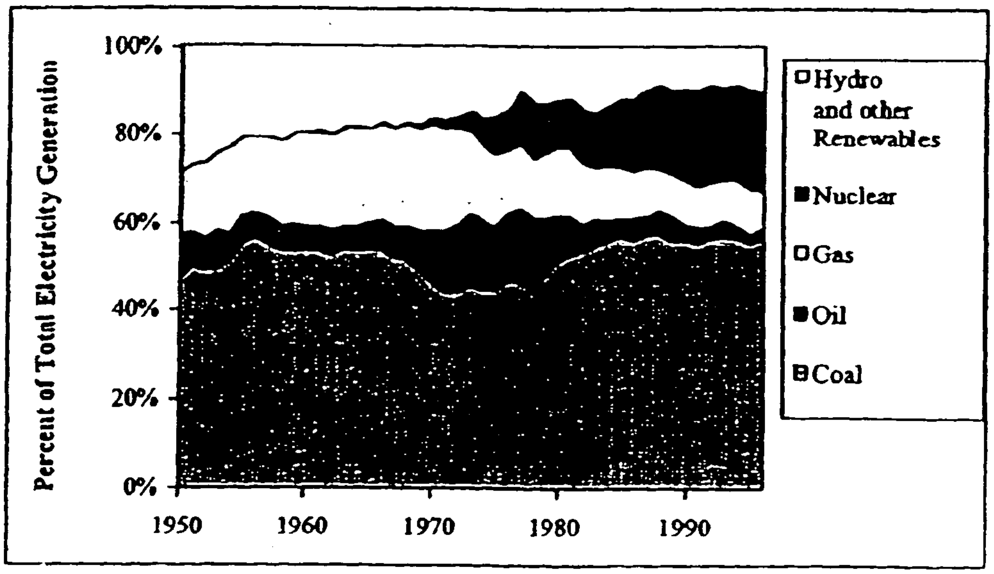
The electric power sector currently is undergoing significant restructuring as it moves from traditional public utility regulation to greater competition. This trend toward increased competition is driven by public policy initiatives at the federal and state levels. In the Energy Policy Act of 1992, the U.S. Congress granted the Federal Energy Regulatory Commission (FERC) additional powers to require electric companies to provide access to their transmis-

Figure 3: Current Electric Generation Fuel Mix



Fuels in the figure are shown clockwise based upon the legend. The current fuel mix represents the percent of electric generation (in MWh) for each fuel type in 1999, the latest year for which data are available. Total exceeds 100% due to independent rounding.
Source: U.S. Department of Energy 2000.

Figure 4. Electric Generation Fuel Mix over Approximately the Last Half-Century



Fuel mix represents the percent of electric generation (in MWh) for each fuel type.
Source: U.S. Bureau of the Census 1975, U.S. Bureau of the Census 1999.

sion grids to potential competitors for the sale of electricity in wholesale markets. In 1996, relying upon these new powers, FERC ordered transmission-owning electric companies to allow open access to their transmission lines in order to facilitate wholesale electricity transactions and thus encourage wholesale competition.

The trend toward greater competition was expanded in 1996 to include competition over consumer (including business) purchases of electricity ("retail competition"), with the passage of laws in California and New Hampshire. Retail competition allows electricity consumers to select their suppliers, although the delivery of the electricity to customers continues to be handled by a regulated local distribution electric utility. As of May 1, 2000, state electric utility regulators, state legislatures, or both, in 24 states and the District of Columbia had made the decision to implement retail competition; actions are pending or ongoing in 10 additional states (U.S. Department of Energy 2000). Federal bills to promote retail competition nationwide were introduced in the 106th Congress.

2. *Future Outlook*

The fuel supply mix is expected to shift over the next two decades as a result of many factors and influences, some of which are linked to increased competitive pressures to lower the cost of electricity generation. These factors include improvements in the efficiency of existing units, the retirement of high-cost facilities, the development of new low-cost units (largely combined-cycle natural gas units), changes in regional transmission capacity, future relative prices for the different fuels and technologies, and the overall growth in electricity demand.

There are, of course, substantial uncertainties involved in predicting the future fuel supply mix, particularly in light of the novel influences of competition:

- Transmission could provide more or fewer opportunities for inter-regional transportation of low-cost power depending upon how much capacity is provided, how rules governing open transmission access are developed, and how much new transmission can be constructed.
- The relative costs of generating power with varied technologies could fluctuate due to differences in relative fuel prices or technological change.
- Successful marketing of "green power" could increase the share of non-hydro renewable energy.
- Differences in regional economic growth could change the relative importance of electricity demand in regions of the country, which could alter the overall fuel mix.
- Overall economic growth could be smaller or larger than predicted.

In addition to these economic and energy market effects, future regulatory initiatives also will influence the electricity fuel mix. Unlike many economic and energy market influences, these future regulatory changes are driven by considerations other than minimizing the cost of providing electricity services. These regulatory initiatives cumulatively could have significant effects on the relative cost and availability of different electricity fuel technologies. The following chapter describes these various regulatory initiatives and their potential impacts on the electricity fuel supply and overall electricity costs.

Part III ✦ Impact of Regulatory Initiatives on Electricity Fuel Use

Virtually every energy and regulatory policy could have some effect on the electricity sector and its generation mix. We focus in this report on regulatory initiatives likely to have the greatest impact. In particular, this section provides background on the following regulatory areas[5]:

- Air quality;
- Climate change;
- Water quality;
- Waste disposal; and
- Energy policies.

Table 1 lists the policy and regulatory initiatives reviewed in this report and their potential timing. This table indicates the large number of influences on the electricity sector and fuel choices over the next two decades. The regulatory issues considered in this chapter generally have not been decided. The initiatives are in different stages of decision-making and implementation. Some initiatives represent initial proposals and others represent regulatory decisions subject to legal review or implementation.

As noted in Chapter I, the purpose of this report it not to analyze the complex policy issues involved in these initiatives. We do not consider the costs and benefits of policy alternatives or evaluate which policies would be superior. Rather, the objective is to describe how each policy would affect different fuel types and their uses in electricity generation. Some policies are fuel-neutral—they increase the costs of all generation by approximately the same amount. In contrast, some policies would have much greater impact on the costs or the availability of certain fuel types.

The general structure of the discussion is simple and the same in each of the policy areas. We first include a brief description of the policy area. We then provide information on the impact of the policy area on electricity fuel types. In some cases, there are studies that provide quantitative estimates of the impact on fuel mix. In other cases, the analyses are qualitative. Where possible, we provide an indication of the overall costs of the regulatory requirement and the impact on rates in order to allow comparison among policy areas.

5 The policies considered in this report do not include broad initiatives affecting all regulations, such as the Executive Order on Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (Executive Order 12898), and the Executive Order on Protection of Children from Environmental Health Risks and Safety Risks (Executive Order 13045).

Table 1. Policies and Regulations Affecting Electric Generation in the Next Two Decades

Policy	*Status*	*Effective Date*
ELECTRIC POWER RESTRUCTURING		
State	Passed/Proposed (various states)	Various
Federal	Proposed	Ongoing
AIR QUALITY		
NO_x		
Title IV	Passed	1995/2002
OTC Budget Program	Passed	1999/2001/2003
SIP Call	Promulgated	2003
New Source Performance Standards	Passed	1999
New Source Review	Litigation/Proposed Reform	Ongoing
Revised NAAQS requirements—8-hour ozone	Promulgated/Remanded	2007
SO_2		
Title IV	Passed	1995/2000
New Source Review	Litigation/Proposed Reform	Ongoing
Revised NAAQS requirements—$PM_{2.5}$	Promulgated/Remanded	2007
Regional Haze	Promulgated	Varies by State
Grand Canyon Visibility Transport Commission	Under Development	2003
Mercury	EPA Determination Forthcoming	Uncertain
CLIMATE CHANGE		
Kyoto	Proposed	2008–2012
WATER QUALITY		
Effluent Guidelines	Passed/Rules under Discussion	Ongoing
Cooling Water—CWA Section 316(b)	Passed/Proposed Rule	Ongoing
WASTE DISPOSAL		
RCRA Phase II	EPA Determination/ Standards Forthcoming	2000/Uncertain
Nuclear	Site Determinations Forthcoming	Ongoing

(Continued)

Table 1. Policies and Regulations Affecting Electric Generation in the Next Two Decades (continued)

Policy	*Status*	*Effective Date*
ENERGY POLICIES		
Hydropower Relicensing	Ongoing	Facility Specific
Nuclear Relicensing	Ongoing	Facility Specific
Renewable Policies		
State	Passed / Proposed (various states)	Various
Federal	Passed / Proposed	Various
Power Plant Facility Siting	Ongoing	Ongoing
Natural Gas Facility Siting	Ongoing	Ongoing
Drilling Constraints		
Outer Continental Shelf Moratorium	Executive Order	Expires 2012
Drilling Constraints on Federal Lands	Rules under Discussion	Ongoing

A. Air Quality

Air emissions from electric generating facilities have been subject to extensive regulation for decades. This section considers the additional near-term initiatives that have been proposed or discussed. The discussion is organized according to the three major pollutants relevant to power plants:

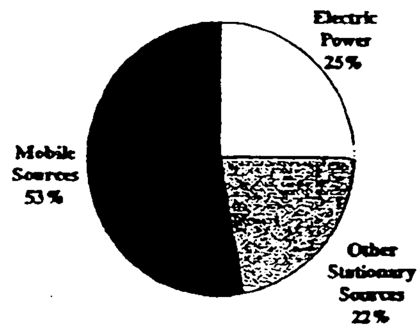
1. *Nitrogen oxides (NO_X) emissions*—These emissions affect ambient concentrations of ozone, particulate matter, and nitrogen dioxide (NO_2).
2. *Sulfur dioxide (SO_2)*—These emissions affect particulate matter as well as SO_2 concentrations.
3. *Mercury*—Mercury is listed as a hazardous pollutant under Section 112 of the Clean Air Act (CAA).

Potential regulations for other emissions, including carbon monoxide (CO), lead (Pb), and volatile organic chemicals (VOCs), are not discussed since major changes in these regulations currently are not under consideration.

1. NO_X Controls

Emissions of NO_X from electric power plants are regulated under various provisions of the CAA. As shown in Figure 5, electric utilities account for approximately 25 percent of national NO_X emissions. Other important sources are vehicle emissions and industrial processes. This section summarizes the current policy initiatives and the likely impact on electricity fuel mix and costs.

Figure 5. Electric Power Share of NO_X Emissions



Source: U.S. Environmental Protection Agency 1998b.

Several major policies regarding NO_X emissions have been developed and proposed in the 1990s, many of which are responses to the 1990 Clean Air Act Amendments (1990 CAAA). These policies include the following:

- *Title IV NO_x Limits*—Requirements of Title IV of the 1990 CAAA that mandate specific reductions in NO_x emissions from power plants nationwide.
- *Ozone Transport Commission (OTC) NO_x Budget Program*—An agreement by the 12 states and the District of Columbia in the OTC to develop a cap-and-trade program for regional NO_x emissions.
- *NO_x SIP Call*—Requirements to cap NO_x emissions in order to reduce regional transport of ozone precursors in the eastern U.S., including requirements for 22 eastern states and the District of Columbia to reduce emissions in their State Implementation Plans (SIP) to address transport (so-called "SIP Call").[6]
- *New Source Performance Standards (NSPS) and New Source Review (NSR) for NO_x*—Controls on new and modified sources of NO_x under the NSR requirements and NSPS.
- *Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS)*—Revisions to NAAQS for ozone and particulate matter, although a May 14, 1999, U.S. Court of Appeals ruling calls these specific standards, and, potentially, the NAAQS program into question. This issue is currently before the U.S. Supreme Court.

6 Implementation of the NO_x SIP Call rule was stayed by the U.S. Court of Appeals for the District of Columbia on May 25, 1999. Following a Court of Appeals decision that essentially upheld the rule, EPA has asked the court to lift the stay. EPA's request has been challenged.

a. Title IV NO_x Program

(1) Policy Overview

Title IV of the 1990 CAAA concerns emissions of two pollutants that are precursors to acid rain, SO_2 and NO_x. The Title IV requirements place limits on the NO_x emissions from coal-fired electric power plants that, in effect, require installation of various emission control technologies. A two-stage approach is used that subjects only a portion of facilities to new standards in Phase I, while imposing new standards on virtually all facilities in Phase II:

- In Phase I, many Group 1 boilers (two specific types of boilers) are subject to standards based on low NO_x burner technology.
- In Phase II, the rest of Group 1 boilers are subject to slightly more stringent standards, and Group 2 boilers (other types of boilers) are subject to standards based on NO_x control technologies.

Phase I requirements took effect in 1996 and Phase II requirements took effect in 2000. Units designated as Phase II units may choose "early election" compliance whereby they achieve Phase I requirements between 1997 and 2007, but are grandfathered from complying with any revised standard until 2008 (Martineau and Novello 1998).

These requirements were projected to achieve annual emissions reductions of about 0.40 million tons per year between 1996 and 1999 and about 2.06 million tons per year in 2000, the first year of Phase II (U.S. Environmental Protection Agency 1999b). The reductions represent 6 percent and 32 percent of actual 1995 NO_x emissions (6.38 million tons) for Phase I and Phase II, respectively (U.S Environmental Protection Agency 1998b).

(2) Policy Impact

Title IV NO_x standards apply only to coal-fired electric power boilers. Phase I affected 265 units designated as Phase I NO_x units and an additional 275 Phase II units subject to "early election" requirements (U.S. Environmental Protection Agency 1999c). There are an additional 339 Group 1 boilers in Phase II (i.e., units that did not choose "early election" compliance) and 145 Group 2 boilers. As shown in Table 2, the EPA estimates the

Table 2. Projected Impact of Title IV Clean Air Act NO_x Requirements

	Annual Cost ($million)[1]	*Average Cost ($/MWh)*
Phase I	$267	$0.15
Phase II	$200	$0.10

Average cost estimates are derived by dividing total costs by estimates of coal-fired generation in 1996 (for Phase I) and 2000 (for Phase II) from the Annual Energy Outlook 1999 (U.S. Department of Energy 1998a).

[1] Year of costs not reported.

Source: U.S. Environmental Protection Agency 1999c and NERA calculations as described above.

annual cost of Phase I to be $267 million. The additional cost of Phase II is estimated by the EPA to be about $200 million per year. These compliance costs are projected to increase the cost of producing coal-fired electricity by about $0.25 per megawatt-hour, with $0.15 per megawatt-hour from Phase I and another $0.10 per megawatt-hour from Phase II.

No estimates are available of the impact of these standards on plant utilization, so it is difficult to assess whether the Title IV requirements have led to a shift in generation to other fuels. In any event, it would be difficult to separate the effect on fuel use of the Title IV NO_X requirements from the effect of Title IV SO_2 requirements.

b. OTC Budget Program

(1) Policy Overview

The 1990 CAAA calls for the formation of the OTC, a regional group that includes 12 Northeast states and the District of Columbia. Many of these jurisdictions have regions that are in non-attainment for ozone. In 1994, the OTC developed a Memorandum of Understanding (MOU) signed by the 13 jurisdictions to achieve region-wide emission reductions in three stages, the first in 1999, the second in 2001, and the third in 2003. These reductions would be achieved by a cap-and-trade program[7] for ozone-season emissions (the NO_X Budget Program) that was outlined in a "model rule." This model rule provides the basis for individual rules that each state in the OTC implements (Carlson 1996). Implementation of this program began in the 1999 ozone season.

(2) Policy Impact

Several studies indicate that the implementation of a NO_X trading program results in significant savings over implementation of a NO_X cap with no trading (Farrell, Carter, and Raufer 1999; ICF 1994; ICF 1995). These studies predict that emissions trading has the potential to reduce the cost of achieving the NO_X Budget cap by 33 to 45 percent. ICF estimates the annual costs of the NO_X Budget Program in 2005 to be $179 million assuming full regional trading and an emission limit of 0.15 pounds per million BTU (ICF 1995).

The studies also project change in fuel utilization as a result of the OTC NO_X cap. In 2005, ICF predicts coal use to fall 4.4 percent with no trading and 2.5 percent with full regional trading (ICF 1995). Natural gas utilization would increase 6 percent under no trading and 0.9 percent with full regional trading.

c. NO_X SIP Call

(1) Policy Overview

Emissions can travel beyond the borders of an individual state. This interstate transport of emissions can adversely affect air quality in downwind regions. The CAA

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7 A cap-and-trade program imposes a cap on the total emissions from relevant sources within a particular geographic region. Sources are able to comply with their individual caps by reducing emissions or by purchasing emissions allowances (i.e., the right to emit a ton) from other sources.

contains several provisions that were revised in the 1990 CAAA to address interstate transport of emissions.

- *Section 110*—Each state's SIP is required to contain provisions that prohibit sources from emitting pollutants that contribute significantly to non-attainment in another state.
- *Section 126*—Downwind states can petition the EPA with scientific evidence showing that emissions from a major source or group of sources are contributing significantly to non-attainment downwind. If the petition is granted, the EPA potentially can prohibit these sources from operating until they achieve appropriate emissions reductions.

The EPA and some individual states have attempted to use these provisions to force reductions in upwind states.

In 1995, the EPA established the Ozone Transport Assessment Group (OTAG), a collaborative process among the 37 eastern-most states. Following OTAG's final report in 1997, the EPA promulgated regulations in 1999 that require 22 states and the District of Columbia to revise their SIPs to reduce NO_X emissions. The so-called NO_X SIP Call includes two major components:

- *Individual State NO_x Caps*—State NO_x caps ("budgets") are based upon emissions targets for individual sources using standard emission factors and projected 2007 activity levels (U.S. Environmental Protection Agency 1998a). The emission targets for electric power sources are based on an emission factor of 0.15 lb./mmBtu (roughly comparable to an 85 percent reduction in emissions for most units).
- *Cap-and-Trade Program for NO_x*—The SIP Call allows for a cap-and-trade program for NO_x emissions across all 22 states. Trading would be allowed among electric power and large industrial boilers, which together account for about 90 percent of the required emissions (U.S. Environmental Protection Agency 1998a).

After having indefinitely suspended implementation of the NO_X SIP Call in response to petitions from eight states affected by it, the District of Columbia Circuit Court of Appeals on March 3, 2000, upheld most aspects of the NO_X SIP Call (Clean Air Compliance 2000a).[8] The EPA asked the Court to end the stay. This request was opposed by several states and

8 During the suspension of the NO_X SIP Call, petitions were filed by New York and nine other Northeastern states under Section 126 of the CAA. On December 20, 1999, the EPA approved the Section 126 petitions from Connecticut, Massachusetts, New York, and Pennsylvania (U.S. Environmental Protection Agency 1999). These petitions would require a total reduction of about 510,000 tons of NO_X annually from utilities in 12 states and the District of Columbia. The schedule for states to comply with these petitions is currently under review. Despite the upholding of the NO_X SIP Call, states must still comply with the Section 126 petitions. Compliance with the NO_X SIP Call may, however, be sufficient to comply with these petitions.

other parties, which also petitioned the Court to delay the May 2003 implementation date. On August 30, the Court extended the SIP Call compliance deadline to May 31, 2004. The implications of this decision are unclear given that the Section 126 petitions granted by EPA still retain the May 2003 date.

(2) Policy Impact

Implementation of the NO_X SIP Call would require the electric power industry to reduce emissions by installing various pollution control technologies—such as selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), natural gas reburn, or by reducing the utilization of higher-emitting facilities. These actions would impose additional costs primarily on coal-fired facilities.[9] Table 3 shows that estimates of the annual cost of these actions in three studies range from about $1.6 billion to $2.8 billion per year. The initial investments associated with these actions are projected in one study to be $13.5 billion (Zinder and Cichanowicz 1998). The increase in the cost of producing electricity at coal-fired units is about $0.80 to $1.42 per megawatt-hour. Figure 6 shows the EPA's estimates of the projected impact of the NO_X SIP Call on capacity. Combined-cycle natural gas capacity is projected to increase by 2,200 MW. Coal and gas/oil-fired steam capacity is projected to decrease.

Table 3. Estimates of the Impact of NO_X SIP Call

			Change in capacity (MW) in 2007		
Study	*Total Annualized Cost ($billion)*[1]	*Average Cost ($/MWh)*[1]	*Coal*		*Oil/Gas-Fired Steam*
EPA (1998a)	$1.58	$0.80	−113	2,200	−201
EPRI (2000)	$1.74	$0.88	NR	NR	NR
Zinder & Cichanowicz (1998)	$2.81	$1.42	NR	NR	NR

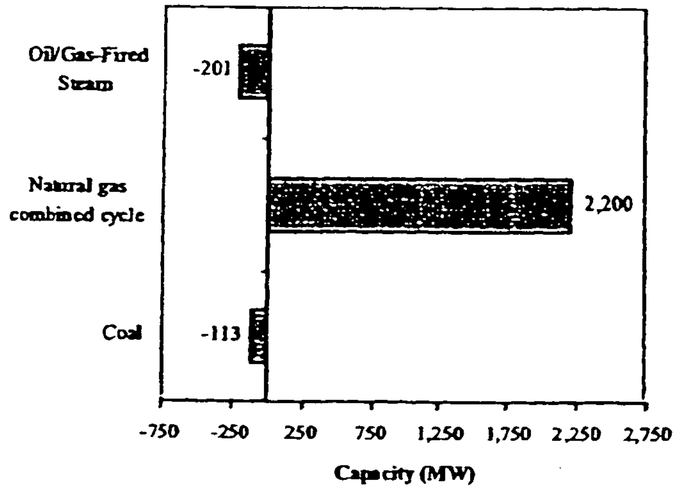
NR—not reported.

The EPA does not report impacts on other fuels though they may occur. Costs are incremental to the Title IV NO_X requirements. Average cost estimates were derived by dividing the total cost by estimates of coal-fired generation in 2005 from the Annual Energy Outlook 1999 (U.S. Department of Energy 1998a).

[1] Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999).

9 The EPA estimates that some small fraction of natural gas units would install pollution controls (U.S. Environmental Protection Agency 1998a).

Figure 6. Changes in Capacity by Fuel and Technology in 2007 Due to the NO_x SIP Call



Source: U.S. Environmental Protection Agency 1998a.

d. New Source Review and New Source Performance Standards

(1) Policy Overview

The New Source Review (NSR) program requires that new facilities and facilities undertaking modifications that would lead to increased emissions obtain NSR permits. A source must undergo NSR under the following two conditions:

1. *Non-attainment Program*—The source must undergo NSR if the source is located in an area currently in non-attainment for a particular pollutant.
2. *Prevention of Significant Deterioration (PSD)*—The source must undergo NSR in an area in attainment if the source emits above a threshold quantity as defined in the PSD regulations.

NSR requires at minimum that Best Available Control Technology (BACT) be applied for any emissions subject to regulation.

On November 3, 1999, the U.S. Department of Justice, on behalf of the EPA, filed suit against seven investor-owned electric companies and the Tennessee Valley Authority (TVA) (U.S. Department of Justice 1999). The suits contend: (1) that the investor-owned electricity companies and TVA undertook modifications to particular plants that the EPA claims trigger NSR; (2) that the companies did not obtain the proper permits and install pollution control equipment required under NSR. The electric companies maintain that these modifications were a part of "routine maintenance" that can be undertaken without triggering NSR (Clean Air Compliance 1999c).

Before this recent litigation, the EPA in 1992 began a multi-party process—including representatives from industry, environmental organizations, states, and the EPA—to revise the NSR regulations. Several issues being addressed in this process are particularly relevant to electric power plants (U.S. Environmental Protection Agency 1996, Environmental Reporter 1999, Martineau and Novello 1998). These issues include:

- *Modifications to trigger NSR*—Under discussion is the approach to measuring the emissions increases from modifications and the level of increased emissions that would trigger NSR.
- *Routine repair and replacement*—Under discussion are the kinds of routine repair and capital replacement that would qualify for an exemption from NSR requirements.
- *Voluntary cap on source emissions*—Under some proposals (including revisions proposed by the EPA in 1996), any plants accepting a voluntary cap on emissions would not be subject to the NSR process. Thus, unlimited modifications could occur as long as plant emissions do not exceed the cap (U.S. Environmental Protection Agency 1996).
- *Relationship between NSR and existing cap-and-trade programs*—There is concern that NSR not negate the flexibility that cap-and-trade programs provide for achieving emissions compliance. The NSR process often requires installation of BACT, which may preclude compliance flexibility, including allowance purchases, encouraged by cap-and-trade programs.
- *Netting*—The NSR contains a netting provision that allows sources to avoid the NSR process by offsetting new emissions with reductions from other emissions sources within the same facility. Currently, many facilities avoid the NSR process by obtaining offsets. Elimination of this provision is under discussion.

In contrast to the NSR program, which requires that sources obtain source-specific permits, NSPS specify a set of technology standards for all new and significantly modified sources. These technology standards are prescribed for particular types of facilities and sources. While not directly related to the NSR program, these standards create a "floor" for the case-by-case NSR technology analyses (Martineau and Novello 1998).

In 1999, the EPA published revisions of the NSPS for NO_X emissions from fossil fuel–based steam generation units (40 CFR part 60 1999). The standard, which is based on a coal-based unit with SCR technology, applies to all fossil fuel–based generation units regardless of fuel type used by the unit. The form of the standard varies between output-based standards for new electricity generation units and input-based standards for existing electricity generation units and industrial units. This revised standard is predicted to reduce NO_X emissions from new and modified sources by 42 percent from current levels (U.S. Environmental Protection Agency 1997b).

(2) Policy Impact

NSR and NSPS require new and modified sources of air emissions to install pollution control equipment. These requirements would add costs to generation facilities burning fossil fuels or biomass. Such requirements would not apply to nuclear, hydroelectric, and non-hydro renewables with the exception of biomass. To the degree that these requirements impose differential costs across different types of facilities, they could affect the generation supply mix.

The EPA projects that the revised NSPS NO_X standards would result in costs of about $40 million annually across all affected sectors, based upon the installation of either SCR or SNCR technologies (U.S. Environmental Protection Agency 1997b). These controls would increase the cost of producing steam for new power generation units about 2 percent. The EPA estimates that the regulations will affect 17 new electricity generation boilers and 381 new industrial boilers over its first five years (U.S. Environmental Protection Agency 1997b).

e. National Ambient Air Quality Standards—$PM_{2.5}$ and 8-hour ozone

(1) Policy Overview

Following passage of the 1970 Clean Air Act, the first National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter (PM) were set in 1971. Revisions were made to the ozone standard in 1979 (Martineau and Novello 1998).[10] States have the responsibility to develop SIPs that demonstrate how the ambient standards will be met within their jurisdictions.

In 1997, the EPA issued new NAAQS for ozone and PM, although these rules have not yet been implemented because of legal challenges. The major changes in the particulate matter standards are:

- *First standard for particulate matter less than 2.5 micrometers*—The previous PM standard was for particles less than 10 micrometers (PM_{10}). The new $PM_{2.5}$ rule sets ambient standards for particles less than 2.5 micrometers in addition to the PM_{10} standards.[11]
- *$PM_{2.5}$ standards more stringent than PM_{10} standards*—The greater stringency of the new $PM_{2.5}$ standards would have two effects. First, many regions would need to increase the level of required emissions reductions for combustion sources beyond the level necessary to achieve the PM_{10} standards. Second, many regions not required to undertake reductions under PM_{10} standards would be required to undertake reductions under $PM_{2.5}$ standards.

10 The EPA is required to perform NAAQS reviews every five years (Martineau and Novello 1998).

11 The new $PM_{2.5}$ rule set the average annual standard for particles less than 2.5 micrometers in diameter at 15 $\mu g/m^3$ and the average 24-hour standard at 65 $\mu g/m^3$.

- *Particulate matter standards affect non-PM emissions as well*—The new $PM_{2.5}$ standard would affect not only direct PM emissions from electric utilities but also emissions of NO_X, SO_2, and VOCs. Once emitted into the atmosphere, these other emissions can be transformed through chemical reactions into $PM_{2.5}$.

The ozone standards also introduced important changes from the earlier standard. These are:

- *New method for measuring ozone levels*—The new ozone standards would change the method for measuring ambient levels from a one-hour maximum average to an eight-hour maximum average.
- *New concentration levels for ozone*—The new method for measuring ozone is accompanied by revised concentration levels for measuring attainment. Under the one-hour standard, a region is in attainment for ozone "when the expected number of days per calendar year with maximum hourly average concentrations above 0.12 ppm is equal to or less than one . . ." (57 *Federal Register* at 13,489 and 13,522). Under the eight-hour standard, a region is out of compliance if the three-year average of the fourth-highest daily maximum eight-hour average concentration is greater than 0.085 ppm.
- *More stringent ozone requirements*—The net result of the changes in method and concentration levels is to make the ozone standard more stringent. This greater stringency would require greater emissions reductions to achieve compliance.

A ruling by the U.S. Court of Appeals for the D.C. Circuit, in Washington, D.C., has created substantial uncertainty over the status of these NAAQS. On May 14, 1999, the D.C. Circuit ruled in the case of *American Trucking Associations, Inc., et al. v. United States Environmental Protection Agency* that the EPA's rationale for setting the ozone and particulate matter NAAQS under the CAA potentially represents an unconstitutional delegation of legislative authority and ordered the EPA to develop "intelligible principles" supporting new standards.[12] The Supreme Court currently is considering this case.

(2) Policy Impact

Implementation of the new eight-hour ozone NAAQS likely would require additional emission reductions from the electric power sector in various states. The extent of these reductions, however, has not been estimated; the regulatory analyses of the new standards did not address the potential effects on electric power emissions. The incremental costs and impact of these standards likely would depend on the implementation status of other policies, such as the OTC NO_X Budget Program, NO_X SIP Call, or the Section 126 petitions, and the effectiveness of these policies at reducing ambient ozone concentrations.

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12 The EPA's ozone rule was remanded for a number of additional reasons, most notably limitations to the EPA's ability to enforce new ozone standards based on Subpart 2 of the 1990 CAAA and the EPA's failure to examine possible health benefits of ozone (*American Trucking Associations, Inc., et al. v. United States Environmental Protection Agency*, 195 F.3d 4; D.C. Cir. 1999).

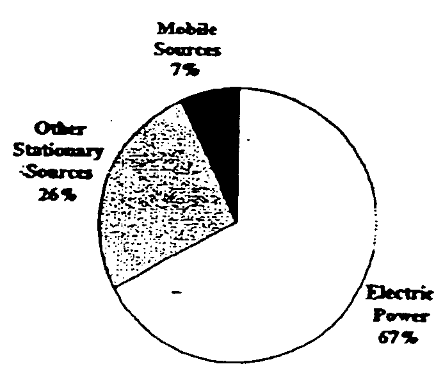
2. SO_2 Controls

Various provisions of the CAA regulate emissions of SO_2. Figure 7 shows that electric utilities account for about 67 percent of SO_2 emissions. This section discusses the various provisions and recent proposals related to utility SO_2 emissions.

Several major policies regarding SO_2 emissions have been developed and proposed in the 1990s, largely in response to the 1990 CAAA. These policies include:

- *Title IV SO_2 Requirement*—Title IV of the 1990 CAAA developed a national cap-and-trade program for SO_2 emissions from power plants.
- *NSPS and NSR for SO_2*—Controls on new sources of SO_2 under the NSPS and NSR requirements.
- *Regional Haze Requirements*—Requirements to reduce haze at all National Parks and Wilderness areas, potentially requiring reduction of SO_2, a precursor to haze, in all 50 states.
- *SO_2 NAAQS*—While the EPA determined in 1996 that no changes to the current SO_2 NAAQS were necessary at this time, environmentalists challenged this decision. A recent court ruling has remanded the decision back to the EPA for further clarification.
- *Particulate Matter NAAQS*—Revisions in the NAAQS for particulate matter, although a recent legal action calls these standards into question.

Figure 7. Electric Power Share of SO_2 Emissions



Source: U.S. Environmental Protection Agency 1998b.

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DOE002-0644

a. Title IV SO_2 Program

(1) Policy Overview

Title IV of the 1990 CAAA mandates a nationwide cap-and-trade program for SO_2 emissions from coal-fired generation units. The major elements of the program are summarized below (Ellerman et al. 1997):

- The program targets only the electric power sector, eventually requiring about a 50 percent reduction in SO_2 emissions from 1980 emissions levels.
- The program is implemented in two-phases:
  - — In Phase I, emissions from 263 units were capped at 8.69 million tons in 1995, falling to 6 million tons in 1999. The eventual number of units capped in 1995 increased to 445 due to the substitution and compensation provisions that allowed Phase II units to opt-in early.
  - — Phase II started in 2000 and expands the affected plants to include virtually every fossil fuel–based electric generating unit, more than 2,000 units. The emissions cap is 9.4 million tons until the year 2010, when it is lowered to 8.95 million tons SO_2 per year.
- The cap is imposed nationally, with no regional constraints on emissions trading.
- Allowances are distributed to utilities using a formula based largely on a unit's heat utilization.[13]
- Allowances may also be banked for use or trade in future years.

(2) Policy Impact

Many analyses have examined the impact of the Title IV SO_2 Program, partly due to its importance as one of the first large-scale cap-and-trade programs. Several recent studies, which incorporate data on Phase I and the effect of more recent developments on Phase II implementation, provide insights into the impact of both phases of the program.

Experience with Phase I indicates that emissions trading can reduce the costs of achieving emissions targets. A study by the MIT Center for Energy and Environmental Policy Research (CEEPR) concludes that emissions trading reduced Phase I costs by 25 to 34 percent (Ellerman et al. 1997).[14] A study by Resource for the Future (RFF), however, suggested that the savings from trading were more limited (Carlson et al. 1998). Table 4 shows that even with these cost savings, the Phase I SO_2 program resulted in estimated annual compliance costs that ranged from $770 million to $960 million. The average cost per ton was estimated by CEEPR at $187 to $210 per ton of SO_2, which was much higher than

13 There were a number of departures from this basic rule, particularly for Phase II units (Joskow and Schmalensee 1997).

14 The CEEPR recently has estimated that emission trading will reduce the cost of achieving the Phase II emission reduction goal by about half. See Ellerman et al. 2000.

Table 4. Costs of Title IV SO_2 Cap-and-Trade Program for Coal-based Units

	Total Annual Cost ($billion)[1]	*Increase in Electricity Cost ($/MWh)*[1]
Phase I		
MIT[2]	$0.77	$0.44
RFF[3]	$0.88–$0.96	$0.50–$0.55
Phase II		
EPRI[4]	$0.89–$1.10	$0.41–$0.53
RFF[5]	$1.10	$0.53

[1] Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999). Average cost estimates were derived by dividing total costs by estimates of coal-fired generation in 1996 (for Phase I), and 2010 (for Phase II), from the Annual Energy Outlook 1999 (U.S. Department of Energy 1998a).

[2] Estimates are based on 1995 data, the first year of compliance.

[3] Estimates are based on 1995 and 1996 data, the first two years of compliance.

[4] Estimates are incremental to Phase I costs. Reported in Smith et al. 1998.

[5] Does not state whether incremental to or inclusive of Phase I costs.

Source: Ellerman et al. 1997, Smith et al. 1998, Carlson et al. 1998, and NERA calculations.

actual market prices of this period, reflecting the large degree of initial over-compliance (i.e., installation of excessive pollution control equipment) (Ellerman et al. 1997).[15] The RFF study estimates the average marginal cost, weighted by each facility's generation, at $180 per ton, which is also consistent with over-compliance by a large number of facilities (Carlson et al. 1998).

Electric utilities used a variety of means to comply with Phase I of the SO_2 trading program, including fuel switching or blending, 53 percent, allowance purchases, 27 percent, and installation of pollution control technology, 16 percent (U.S. Department of Energy 1997). Seven affected facilities, representing 1,342 megawatts or 1.5 percent of total affected capacity, have closed, although other factors played a large role in the closure decisions.

Phase II will impose additional compliance costs, although the costs will be delayed due to the large quantity of banked allowances created during Phase I. These banked allowances are expected to delay the full imposition of the Phase II cap until 2007 to 2010 (Smith et al. 1998). As shown in Table 4, once the banked allowances are used, the incremental costs of Phase II are estimated to range from $0.89 to $1.10 billion per year in 2010.[16] Due to a variety of factors, such as a reduction in the cost of fluidized gas

15 The initial over-compliance was due to a variety of factors that led firms to expect higher SO_2 allowance prices than actually occurred. Decisions to invest in expensive scrubbers were made based upon these relatively high SO_2 prices. See Ellerman et al. 1997, and Bohi and Burtraw 1997.

16 The Electric Power Research Institute (as referenced in Smith, Platt, and Ellerman 1998) estimates that lower coal utilization, possibly due to "major new regulations," might cause incremental costs to fall as low as $0.39 billion ($1997).

desulfurization (FGD) technology and greater access to low-sulfur coal, these costs are substantially lower than initial estimates produced before the implementation of Phase I. Average costs are estimated to be about $200 per ton, while marginal costs are estimated to range from $276 to $498 per ton.[17] These costs are higher than the current allowance prices, which are less than $150 per ton.

The SO_2 cap-and-trade program increases the cost of generating electricity from coal-fired units. As shown in Table 4, Phase I has increased the cost of electricity from coal-fired units between $0.44 and $0.55 per megawatt-hour. Phase II is estimated to increase costs between $0.41 and $0.53 per megawatt-hour.

b. New Source Review and New Source Performance Standards

(1) Policy Overview

As described above, all new power plants or existing power plants making substantial modifications are required to undergo a NSR permitting process or comply with NSPS; the specific requirement depends on the location and quantity of emissions generated. The NSPS require that sources install BACT to control SO_2 emissions (Martineau and Novello 1998). As noted above, the EPA is in the process of revising the NSR process and has filed suit against seven investor-owned electric companies and the TVA alleging NSR violations.

(2) Policy Impact

NSR and NSPS require new and modified sources of air emissions to install pollution control equipment. These requirements would add costs to generation facilities burning fossil fuels or biomass. Such requirements would not apply to nuclear, hydroelectric, and non-hydro renewables, with the exception of biomass generation. To the degree that such requirements impose differential costs across different types of facilities, they may affect the mix for power generation.

c. National Ambient Air Quality Standards—SO_2 and $PM_{2.5}$

(1) Policy Overview

As noted above, the CAA requires the EPA to set a NAAQS for SO_2. The NAAQS for SO_2 was last revised in 1978. Although the EPA in May 1996 determined that there is no need to revise the SO_2 standard, environmentalists challenged this decision. In January 1998, the D.C. Circuit remanded the EPA's decision that no new SO_2 NAAQS was needed to the EPA for clarification (*American Lung Association et al. v. United States Environmental Protection Agency*, 96-1255 (D.C. Cir., *decided*, January 30, 1998)).

The NAAQS for particulate matter also affects requirements for reductions in SO_2 emissions, since SO_2 can be transformed into particulate matter through atmospheric

17 This range reflects variation in a limited number of parameters. Incorporation of other uncertainties could raise costs to about $600 per ton (Smith, Platt, and Ellerman 1998).

reactions. The 1997 revisions to the particulate matter standard could lead to additional reductions in SO_2 emissions, due to a need to comply with new standards for particulate matter smaller than 2.5 micrometers. As noted earlier, legal actions put the new $PM_{2.5}$ standard in doubt.

(2) Policy Impact

The potential $PM_{2.5}$ standards may require significant reductions in SO_2 emissions in many regions. The EPA has not stated whether national federal programs would be implemented as part of a compliance program. With respect to the electric power sector, the EPA appears to prefer a further tightening of the Title IV SO_2 cap (U.S. Environmental Protection Agency 1997c, U.S. Environmental Protection Agency 1999a). The EPA has not announced the quantity of additional SO_2 emissions reductions that would be sought if the SO_2 cap were further tightened, but it has suggested that additional reductions of 45 to 70 percent below the Title IV Phase II cap would be likely (U.S. Environmental Protection Agency 1997c, U.S. Environmental Protection Agency 1999a). The EPA's 1997 Regulatory Impact Assessment (RIA) for the $PM_{2.5}$ standard assumes a 60 percent reduction in SO_2 emissions relative to current Title IV programs. This reduction implies a target of 3.58 million metric tons of SO_2, compared to a 9.4 million metric ton cap under Title IV (U.S. Environmental Protection Agency 1997c). A more recent EPA analysis considers four SO_2 reductions scenarios ranging from 57 to 71 percent; these scenarios imply 2007 targets of 4.2 million tons and 2.8 million metric tons, respectively (U.S. Environmental Protection Agency 1999a). Actual emissions in the year that caps are tightened may exceed emission caps due to banking of allowances.

Several studies have analyzed the impacts of further tightening the SO_2 cap, including two studies by the EPA and a study by the Electric Power Research Institute (U.S. Environmental Protection Agency 1997c, U.S. Environmental Protection Agency 1999a, Electric Power Research Institute 2000). These studies, which examine a range of possible reductions, provide some perspective on the possible impact from additional SO_2 reductions. Table 5 reports estimates of the annualized cost and cost per kilowatt-hour for attaining the SO_2 targets analyzed in these studies. The incremental costs of additional reductions beyond Phase II requirements are estimated to be between \$2.2 and \$3.4 billion annually depending on the emission target, which ranges from 2.8 million metric tons to 4.5 million metric tons. The EPRI results suggest that costs would be somewhat higher than those reported by the EPA.

Table 5 also reports estimates from the Reason Public Policy Institute (RPPI) of the combined costs to the electric power sector of revised ozone and $PM_{2.5}$ standards (Smith et al. 1997). This study estimates the full additional cost to utilities of achieving compliance in all regions to be \$20.4 billion annually. Since this cost estimate is incremental to the NO_X SIP Call, it is likely that the majority of these costs are attributable to the $PM_{2.5}$ rather than the ozone standards. Results from the RPPI study differ from the EPA and EPRI studies because the RPPI study is based on reductions necessary to achieve compliance in all regions. In contrast, the EPA and EPRI studies only examine a tightening of the SO_2 cap, which may not be adequate to achieve full compliance in all regions (U.S. Environmental Protection Agency

Table 5. Estimates of the Impact of Additional SO_2 Reductions

				Impacts in 2010			
				Coal		*Natural Gas*	
Study	*Annual Emissions Cap*[1] *(million mtons)*	*Total Annual Cost ($billion)*[2]	*Average Cost ($/MWh)*[2,3]	*Capacity (GW)*	*Generation (billion kWh)*	*Capacity (GW)*	*Generation (billion kWh)*
EPA (1999)							
Low	2.8 (in 2007)	$3.4	$1.65	−3	−85	7	84
High	4.2 (in 2007)	$2.2	$1.06	−2	−47	4	46
EPA (1997)[4]	5.2 (in 2005)	$3.2	$1.53	NR	NR	NR	NR
EPRI (2000)	4.5 (in 2007)	$2.5	$1.21	NR	NR	NR	NR
RPPI / DFI[5]	NR	$20.4	$9.90	NR	NR	NR	NR

NR—not reported.

[1] Actual emissions at the date when the cap is tightened further may exceed emissions caps due to banking of allowances.

[2] Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999).

[3] Average cost estimates were derived by dividing the total costs by estimates of coal-fired generation in 2010 from the Annual Energy Outlook 1999 (U.S. Department of Energy 1998a).

[4] The SO_2 trading cap is for a scenario that achieves partial attainment with the $PM_{2.5}$ standards. There are 30 potential non-attainment counties.

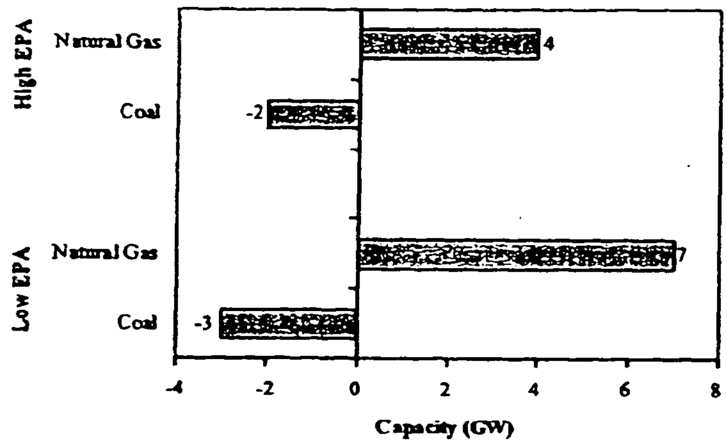
[5] Includes the costs of reducing NO_X as well as SO_2 emissions to comply fully with both revised ozone and $PM_{2.5}$ standards. Since the costs of reducing NO_X under the SIP Call are not included, these estimated costs likely are attributable to SO_2 reductions.

Source: U.S. Environmental Protection Agency 1999a, U.S. Environmental Protection Agency 1997b, Electric Power Research Institute 2000, Smith et al. 1997, and NERA calculations.

1997c, U.S. Environmental Protection Agency 1999a, Electric Power Research Institute 2000).

The 1999 EPA study also reports the impact of reductions in the SO_2 cap on the electricity fuel mix. The EPA reports that additional SO_2 reductions would be achieved primarily through installation of FGD control technology and fuel switching, with relatively limited increases in natural gas combined-cycle technology. As shown in Figure 8, the EPA predicts that combined-cycle natural gas capacity in 2010 would increase by 7 gigawatts under the 2.8 million metric ton target, a 6 percent increase in natural gas capacity. Coal capacity would decrease by 3 gigawatts, a 1 percent decrease in capacity. Predicted changes in generation are larger, reflecting increased utilization of existing gas-fired units and decreased utilization of coal-fired units. As shown in Figure 9, coal-fired generation is predicted to decrease by 85 billion kilowatt-hours, a 4 percent decrease, and gas-fired generation would increase by 84 billion kilowatt-hours, an 11 percent increase.

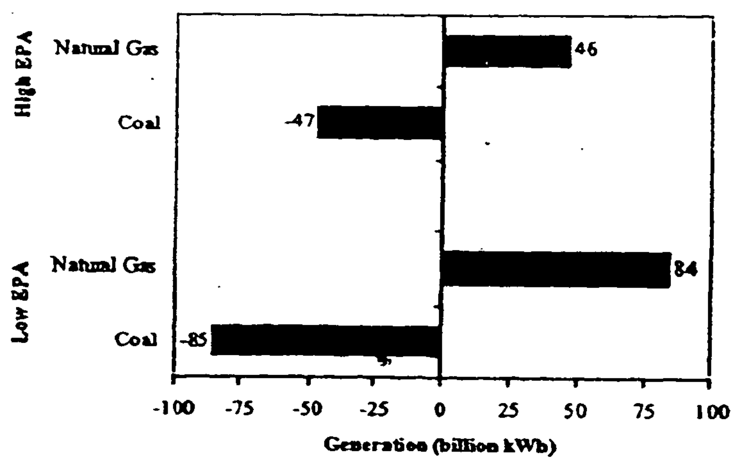
Figure 8. Changes in Coal and Natural Gas Capacity in 2010 Due to Additional SO_2 Reductions beyond Title IV SO_2 Requirements



Low EPA corresponds to an SO_2 cap of 2.8 million metric tons, and High EPA corresponds to an SO_2 cap of 4.2 million metric tons.

Source: U.S. Environmental Protection Agency 1999a.

Figure 9. Changes in Coal and Natural Gas Generation in 2010 Due to Additional SO_2 Reductions beyond Title IV SO_2 Requirements



Low EPA corresponds to an SO_2 cap of 2.8 million metric tons, and High EPA corresponds to an SO_2 cap of 4.2 million metric tons.

Source: U.S. Environmental Protection Agency 1999a.

In summary, further reducing SO_2 emissions to achieve compliance with a $PM_{2.5}$ NAAQS would result in substantial additional costs. Estimates of these additional costs range from $2.2 billion to $3.4 billion depending upon the national SO_2 emission target and when it would be implemented. These cost estimates, however, assume that reductions by electric utilities are limited to a further tightening of the national cap. Costs could be substantially greater if further electric power SO_2 reductions were sought to comply with the revised NAAQS for particulate matter in all locations.

d. Regional Haze

(1) Policy Overview

The 1977 amendments to the CAA established a national goal to eliminate existing (and prevent future) visibility problems in 156 National Parks and Wilderness areas (called Class 1 areas), due to human sources of emissions. Visibility problems are due to regional haze, which is created by various pollutants, including particulate matter, sulfates, and nitrates. In 1980, the EPA promulgated rules that would require emission reductions if visibility problems were reasonably attributable to a single emission source. In July 1999, the EPA published a final rule that would require reductions if visibility problems in Class 1 areas were caused by groups of facilities (64 *Federal Register* 35,715 1999). This rule has been challenged in the D.C. Circuit by several industries. Implications of this ruling include:

- *Incorporation of regional haze into SIPs*—This rule would require states to incorporate actions to reduce regional haze into their SIPs.
- *All states affected*—Because the Class 1 sites are distributed across the country and many of the targeted pollutants are transported regionally, all 50 states are required to develop long-term plans to meet "reasonable progress goals."
- *Targets not defined*—The EPA specified that SIPs must achieve "reasonable progress goals," though they did not specify what these progress goals should be.[18]
- *Best Available Retrofit Technology (BART) requirements*—The haze rule does require states to identify BART for up to 26 different types of emissions sources placed into operation between 1962 and 1977. The rule does allow flexibility in BART requirements if states propose alternative measures, such as an emissions trading program, that achieve more progress than source-by-source BART controls.

18 A goal of one decaview visibility improvement per decade was included in the proposed version of the rule. National progress goals were not specified in the final version because of the variation in improvements necessary to meet the long-run goal of achieving background levels of visibility impairment within 60 years.

- *Regional planning efforts*—The EPA is encouraging regional planning efforts to address visibility impairment at the Class 1 areas since many sites receive emissions from more than one state.

The regulations include specific provisions allowing states in the Grand Canyon Visibility Transport Commission (GCVTC) to meet regional haze SIP planning requirements based on recommendations of the GCVTC.[19] Drawing upon these recommendations, the Western Regional Air Partnership is currently developing a regional SO_2 reduction plan that would phase-in emissions targets from 2003 to 2018. Several proposals are currently under consideration (Western Regional Air Partnership 2000). These proposals include a cap-and-trade program for stationary source emissions, with proposed emission caps ranging from 373,000 to 635,000 tons of SO_2 annually.

(2) Policy Impact

The impact of regional haze regulations will depend on how individual states implement their SIPs, the degree of regional coordination, and the levels of improvement in visibility sought. The EPA's Regulatory Impact Assessment (RIA) projects that the costs may range from $0.9 billion to $5.5 billion annually (updated to 1999 dollars), depending upon the magnitude of visibility improvements sought and the deadline by which such improvements must be achieved (U.S. Environmental Protection Agency 1997). These costs are incremental to the costs of the proposed NAAQS for eight-hour ozone and $PM_{2.5}$. The costs to the electric power sector, however, are not provided in the RIA. One study projects that the costs of one deciview[20] of improved visibility for the West alone would be about $5 billion annually, and that the costs of subsequent decaview improvements would be substantially larger (Smith 1997).[21]

Haze regulations are likely to have the largest impact on sources in locations upwind from affected National Parks and Wilderness areas and those producing the most significant emissions. Western states are likely to incur higher costs than eastern states (Smith 1997). Since SO_2 emissions are among the most significant precursors to regional haze, stationary fossil fuel sources, particularly coal-fired power generation units, are likely to be among the most affected sources.

3. *Mercury Controls*

Section 112 of the CAA requires the EPA to set standards for hazardous air pollutants (HAPs). These standards are called National Emissions Standards for Hazardous Air Pollutants (NESHAP). The EPA currently is considering establishing a NESHAP or comparable regulatory program for mercury emissions from electric utility power plants. Electric

19 These states include Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming.

20 A deciview is a visibility scale that expresses uniform changes in haziness across the range of visibility conditions, from pristine to extremely hazy (40 CFR 35714 1999).

21 The year of this cost estimate is not specified.

utilities account for about 30 percent of national, anthropogenic mercury emissions, as shown in Figure 10.

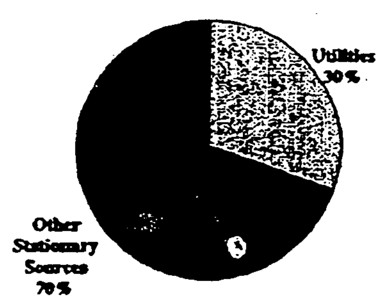
a. Policy Overview

Section 112 of the 1990 CAAA contains several provisions related to emissions of mercury from electric utility power plants (Center for Clean Air Policy 1998):

- *Maximum Achievable Control Technology (MACT)*—Electric power plants emit a number of HAPs, including mercury. The MACT program is one of the regulatory options available to the EPA under Section 112 to address sources that emit HAPs.[22]
- *The Great Waters Program*—The EPA may require additional controls on sources that emit HAPs in levels that endanger human health and the environment in the Great Waters area, which include the largest inland lakes and coastal areas.
- *Utility HAPs Report*—Section 112(n)(1)(a) requires the EPA to submit a report to Congress on threats to public health that stem from the release of HAPs from electric utilities. The 1990 CAAA also gave the EPA the authority to regulate electric utility HAP emissions if the Agency deems it necessary.

The Utility HAPs Report was released in February 1998, finding that "on balance, mercury from coal-fired utilities is the hazardous air pollutant of greatest public health concern," although the extent of exposure due to power plants is uncertain (U.S. Environmental Protection Agency 1998d). The report notes that the "EPA has not been able to identify any currently demonstrated, feasible, and commercially available technology for

Figure 10. Electric Power Share of Anthropogenic Mercury Emissions



Source: U.S. Environmental Protection Agency 2000b.

22 Sources within a controlled industry category that emit at least 10 tons per year of one HAP or 25 tons per year of two or more HAPs must comply with MACT requirements.

reducing various chemical forms of mercury emission from coal-fired utilities" (U.S. Environmental Protection Agency 1998d).

The National Academy of Sciences (NAS), as mandated by Congress, issued a report in July 2000, indicating that the risk of adverse health effects from exposure to mercury is low for the majority of the American public. The NAS report suggested that additional research is necessary to identify and reduce possible risks among sensitive population groups.

After considering the findings of the Utility HAP Report and the NAS study, the EPA recently made a regulatory determination for mercury (U.S. Environmental Protection Agency 2000b) in which the agency decided to move forward with the development of a proposed rule. A proposal is expected by December 2003, with a final rule issued about one year later. The EPA is currently reviewing preliminary data from the Mercury Emissions Information Collection Effort, which is focusing on emissions from 84 coal-based electric units and the mercury content in coal burned at over 1,000 units (Clean Air Compliance Review 1999a).

b. Policy Impact

A NESHAP for mercury would target predominantly coal-fired electric power units (Center for Clean Air Policy 1998, U.S. Environmental Protection Agency 1998c).[23] Although many control options exist for reducing mercury emissions, there is limited information on the cost and effectiveness of these options when used on coal-fired units. A report by the Center for Clean Air Policy (CCAP) reports costs for six approaches. Aside from coal switching, all estimates are greater than $33,000 per pound of mercury (Center for Clean Air Policy 1998).[24] The EPA has produced two studies on the costs of mercury control at coal-fired units. Its first report estimated that 90 percent mercury reduction could be achieved at an average cost of $67,000 to $70,000 per pound (U.S. Environmental Protection Agency 1997a). A recent report produced revised estimates of $28,000 to $34,000 per pound (U.S. Environmental Protection Agency 1999a). In comparison, sectors already subject to MACT typically achieve emissions reductions for less than $5,000 per pound (Center for Clean Air Policy 1998).

Table 6 provides summaries of the estimated costs of achieving a 90 percent reduction in electric power mercury emissions. Estimated annualized costs of implementing mercury MACT range from approximately $1.83 billion to $6.08 billion per year. The high estimates are based on the EPA's initial examination of a reduction in mercury emissions (U.S. Environmental Protection Agency 1997a), and the low estimates are from the EPA's most recent analysis (U.S. Environmental Protection Agency 1999a). Implementation of emissions

23 The EPA's Regulatory Determination suggests the agency also would regulate oil-fired units. However, coal-fired generation represents 99 percent of mercury emissions from electric power boilers (U.S. Environmental Protection Agency 2000b).

24 Coal switching costs vary widely depending on the type of coal used. The potential of coal switching will depend on available quantities of coal with low mercury content.

Table 6. Impact of a Policy to Reduce Mercury from Coal-fired Facilities

	Total Annual Cost ($billion)[1]	Average Cost ($/MWh)[1,2]	Coal Impact		Natural Gas Impact	
			Capacity (GW)	Generation (billion kWh)	Capacity (GW)	Generation (billion kWh)
Mercury MACT	$1.83–$6.08	$0.88–$2.95	0	–15	0	15
Mercury Trading	$1.40–$2.04	$0.68–$0.99	0	–41	0	40

Policies achieve a 90 percent reduction in coal-fired mercury emissions.

[1] Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999).

[2] Average cost estimates were derived by dividing total costs by estimates of coal-fired generation in 2010 from the Annual Energy Outlook 1999 (U.S. Department of Energy 1998a).

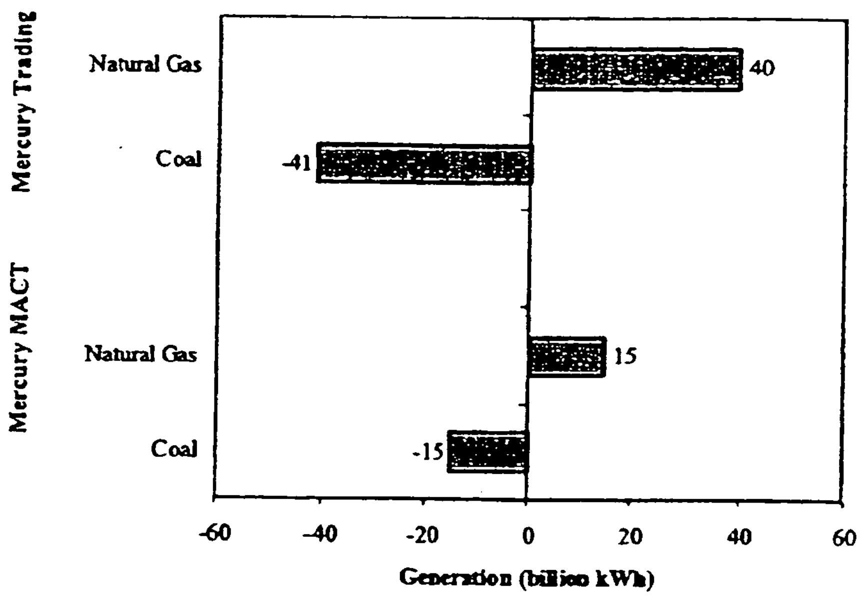
Source: U.S. Environmental Protection Agency 1997a, U.S. Environmental Protection Agency 1999a, and NERA calculations.

trading is projected to lower costs to between $1.40 billion and $2.04 billion (U.S. Environmental Protection Agency 1999a), although it is important to note that development of a MACT program to address mercury emissions likely would prohibit meaningful trading. These latter estimates assume implementation of the NO_X SIP Call, which may partially account for the reduction in costs from previous EPA estimates.

Implementation of controls on electric utility mercury emissions could lead to shifts in fuel utilization. Table 6 shows that the EPA predicts that implementation of a MACT for mercury would not result in any changes in capacity for either coal or natural gas units but would lead to shifts in generation. Figure 11 shows the predicted changes in generation in 2010. The EPA projects that the mercury MACT would decrease coal-fired generation by 15 billion kilowatt-hours and increase natural gas generation by an equivalent amount (U.S. Environmental Protection Agency 1999a). Implementation of a cap-and-trade program is projected to lead to greater shifts in generation, with coal-fired generation decreasing by 41 billion kilowatt-hours and gas-fired generation increasing by approximately the same amount. Predicted changes in other electricity sources, such as nuclear or renewable power, are not reported.

The impact of mercury controls on fuel use appears to be related to the policies for other emissions, notably SO_2 and CO_2. When a 50 percent SO_2 reduction is implemented along with mercury MACT, coal generation is projected to fall by 25 billion kilowatt-hours rather than 15 billion kilowatt-hours for the mercury MACT alone (U.S. Environmental Protection Agency 1999a). In contrast, when carbon reductions are also required, the projected reduction in coal generation from mercury MACT is only 1 billion kilowatt-hours (U.S. Environmental Protection Agency 1990a).

Figure 11. Changes in Coal and Natural Gas Generation in 2010 Due to Mercury Policies



Source: U.S. Environmental Protection Agency 1999a.

B. Climate Change

Within the past decade, climate change has emerged as a major focus of U.S. and international environmental policy discussions. Many studies have estimated the economic impacts of the Kyoto Protocol, which would commit the U.S. and other developed nations to substantial reductions in CO_2 and other greenhouse gas (GHG) emissions by the 2008–12 time period.

Kyoto Protocol

The Kyoto Protocol represents the first international initiative that would create binding GHG targets.

a. Policy Overview

In December 1997, representatives of the world's nations gathered in Kyoto, Japan, under the auspices of the Framework Convention on Climate Change. The Third Conference of the Parties (COP3) produced the Kyoto Protocol. The provisions of the Kyoto Protocol are summarized as follows:

- Industrialized nations, the so-called "Annex I" parties, agreed to reduce their emissions of six greenhouse gases by about 5 percent, on average, between 2008 and 2012, relative to 1990 levels. Different national emission targets were set. The U.S. target is a 7 percent reduction relative to 1990 levels.
- Trading of national emission rights (targets) among Annex I countries is allowed, as is project-by-project bilateral exchange of credits (joint implementation) among Annex I countries.
- Annex I countries can receive credits for reductions accomplished in non-Annex I countries (developing countries), using the Clean Development Mechanism (CDM).
- Banking of emission credits to subsequent periods is allowed, (i.e., between the 2008 to 2012 compliance period and subsequent periods) but targets for periods beyond 2012 are not specified.
- Nations are given sovereignty in selecting domestic policy instruments to achieve the national targets.
- Provisions are made to include "sinks" (i.e., carbon sequestration) in the calculation of compliance with targets.
- The Protocol enters into force only when it is ratified by 55 nations, as long as those countries include Annex I countries representing at least 55 percent of 1990 Annex I CO_2 emissions.

International developments are proceeding to complete elements of the Kyoto Protocol. In November 1998, during the Fourth Conference of the Parties (COP4) in Buenos Aires, Argentina, delegates developed a work plan for the following two years, including schedules for concurrent development of rules for international trading, joint implementation, and CDM. In October and November of 1999, the Fifth Conference of Parties (COP5) met in Bonn, Germany, and continued work to develop the rules and procedures to implement the Protocol.

Although a total of 83 countries and the European Union have signed the treaty, only 29 countries—all developing nations—have ratified the Protocol. The U.S. has signed the treaty, but has not committed to ratifying the Kyoto Protocol. In fact, the U.S. Senate, by a vote of 95–0, is on record that it will not provide its advice and consent to the Protocol unless: (1) the Protocol also mandates specific commitments to limit or reduce GHG emissions in the same compliance period by developing countries; (2) the Protocol does no serious harm to the U.S. economy (U.S. Senate 1997). President Clinton has indicated that he will not submit the treaty to the Senate absent these conditions (Tebo 1998). Implementation of the Kyoto Protocol, therefore, is clearly speculative. Assessing the impacts of the Kyoto Protocol, however, is useful to illustrate the implications of limits on GHG emissions.

b. Policy Impact

Virtually every study indicates that implementation of the Kyoto Protocol in the U.S. could result in a major shift in the electric generation fuel mix. The impact of the Kyoto Protocol in the U.S. also depends substantially on the availability (and price) of international CO_2 credits. As noted, the Kyoto Protocol allows for several trading mechanisms designed to reduce the global cost of meeting the targets. As many studies have indicated, the global cost of meeting Kyoto targets would be substantially reduced if the U.S. and other Annex I nations could take advantage of relatively cheap emission reductions in developing countries (see, e.g., Weyant and Hill 1999, Toman et al. 1999). With the exception of the CDM, however, the programs only allow trading among Annex I countries. In addition, as numerous authors have noted, many hurdles would have to be overcome before full international trading could be implemented successfully (e.g., Harrison 1997, Kopp et al. 1998).

The Energy Information Administration (EIA) has evaluated the following cases regarding CO_2 reductions (U.S. Department of Energy 1998b):

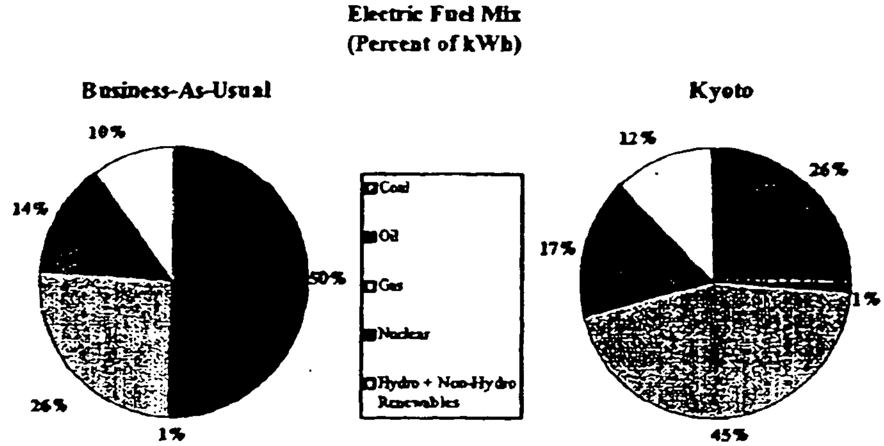
1. *Business-As-Usual (BAU)*—This provides a benchmark, i.e., no domestic CO_2 targets. Under BAU, CO_2 emissions are projected to be 33 percent above 1990 levels in 2010 and 43 percent above 1990 levels in 2020.
2. *Full International Trading*—This case assumes that the U.S. domestic target would be 24 percent above 1990 levels, which implies that the bulk of the required U.S. reduction would be obtained through international CO_2 trading.
3. *Annex I Trading*—This case assumes a domestic target equal to 9 percent above 1990 levels, with Annex I trading being used to obtain the additional credits needed to achieve the Kyoto target.
4. *No Trading*—This case assumes that the entire U.S. target would have to be achieved by domestic CO_2 reductions. In this case, the domestic CO_2 target is assumed to be 3 percent below 1990 levels. (The remainder of the Kyoto requirement that U.S. carbon emissions be 7 percent below 1990 levels is assumed to be achieved by decreases on other GHG emissions and increases in carbon sinks.)

Figures 12 and 13 report EIA results on the impact of the Kyoto Protocol based upon the Annex I trading case. As discussed below, the other assumptions regarding international trading lead to very different results. The two figures show the fuel mix, under BAU and Kyoto, in 2010 and 2020, respectively.

Figure 14 shows historical trends in fuel mix and fuel mix projections based upon implementation of the Kyoto Protocol, combined with NO_X and SO_2 policies, as evaluated by the Electric Power Research Institute (Electric Power Research Institute 2000). The results are similar to the EIA results.

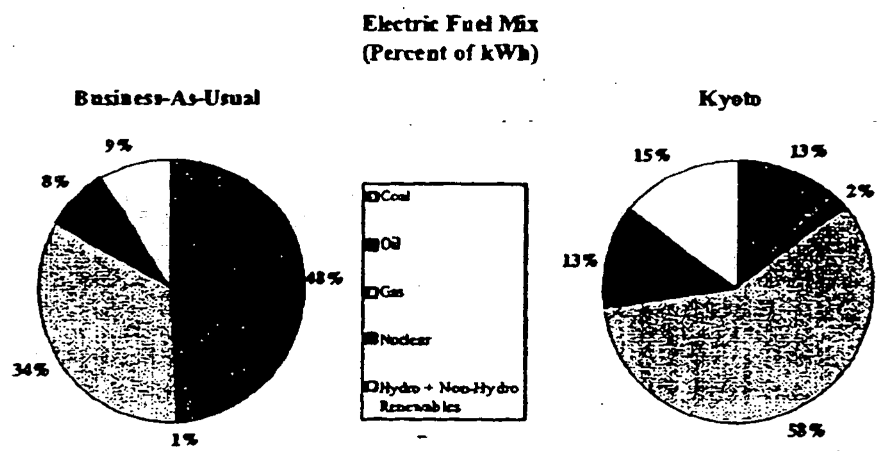
These results indicate that implementation of the Kyoto requirements in the U.S.—Under the assumption of Annex I trading—would lead to dramatic shifts in the electric power generation fuel mix, particularly by 2020. The shifts include:

Figure 12. Electric Generation Fuel Mix in 2010, Business-As-Usual and Kyoto



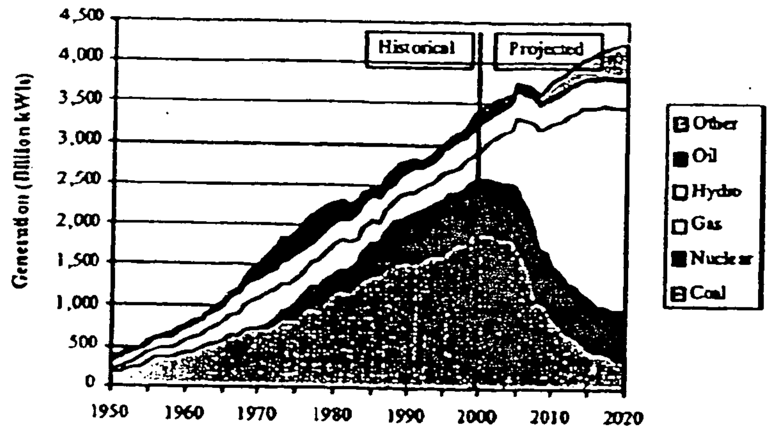
Assumes U.S. domestic CO_2 target equal to 1990 + 9 percent (Annex I Trading).
Source: U.S. Department of Energy 1998b.

Figure 13. Electric Generation Fuel Mix in 2020, Business-As-Usual and Kyoto



The Kyoto case assumes U.S. domestic CO_2 target equal to 1990 + 9 percent (Annex I Trading).
Source: U.S. Department of Energy 1998b.

Figure 14. Impact of Regulatory Policies on U.S. Electric Generation Fuel Mix



Fuels in the figure shown in the same order as the list. Projected impact based on a domestic Kyoto target of 9 percent above 1990 levels (Annex I trading case), the NO_X SIP Call, and a 50 percent reduction in electric utility SO_2 targets.

Source: U.S. Bureau of Census 1975, U.S. Bureau of Census 1999, and Electric Power Research Institute 2000.

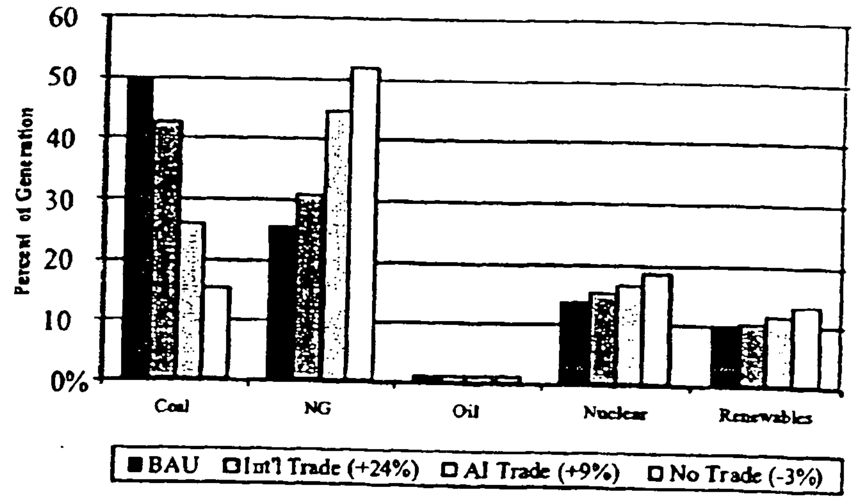
- *Coal percentage would decline dramatically*—The percentage of generation accounted for by coal would decline in 2010 from 50 percent under BAU to 26 percent under Kyoto and in 2020 from 48 percent under BAU to 13 percent under Kyoto.
- *Natural gas percentage would increase substantially*—The generation percent accounted for by natural gas would increase in 2010 from 26 percent under BAU to 45 percent under Kyoto, and in 2020 from 34 percent under BAU to 58 percent under Kyoto.
- *Both nuclear and renewable percents would increase, particularly by 2020*—By 2020, both nuclear and renewable percents would be higher in the Kyoto case relative to BAU. Nuclear would go from 8 percent of generation under BAU to 13 percent under Kyoto. Renewables would go from 9 percent under BAU to 15 percent under Kyoto.

Note that oil remains a very small percent of the electricity fuel mix under either BAU or Kyoto.

Figures 15 and 16 show the effects of different Kyoto international trading assumptions on the fuel mix percentages for 2010 and 2020, respectively, based upon the EIA analysis. The range is substantial, particularly in 2020:

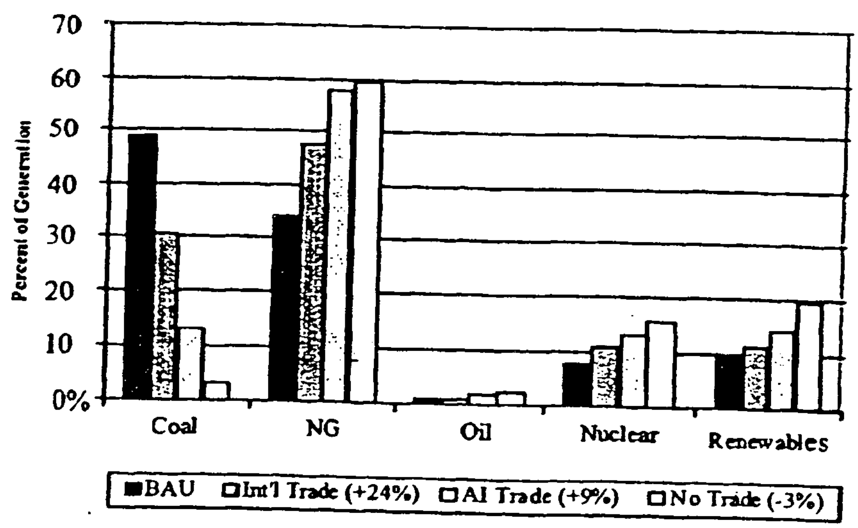
- The coal percent in 2020 for Kyoto ranges from 3 percent under No Trading to 30 percent under Full International Trading.

Figure 15. U.S. Electric Generation Fuel Mix under Different Kyoto Trading Cases, 2010



Source: U.S. Department of Energy 1998b.

Figure 16. U.S. Electric Generation Fuel Mix under Different Kyoto Trading Cases, 2020



Source: U.S. Department of Energy 1998b.

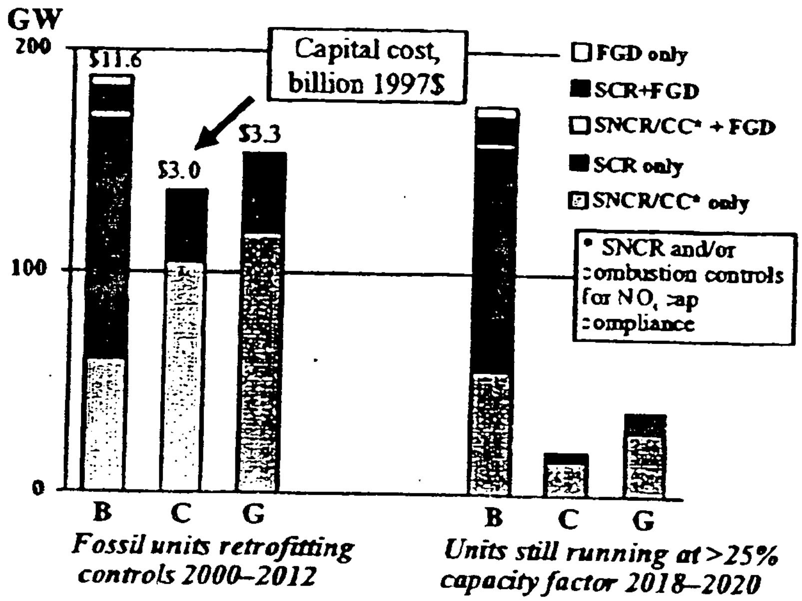
- The natural gas percent in 2020 for Kyoto ranges from 60 percent under No Trading to 47 percent under Full International Trading.
- The nuclear percent in 2020 for Kyoto ranges from 15 percent under No Trading to 11 percent under Full International Trading.
- The renewables percent in 2020 for Kyoto ranges from 20 percent under No Trading to 11 percent under Full International Trading.

As these results show, full international trading would substantially reduce the economic impact of the Kyoto Protocol on the U.S. electricity system. As shown in the Appendix, similar shifts in the electric power fuel mix due to the Kyoto Protocol are predicted by other studies.

In addition to inducing large shifts in the electricity generation mix, implementation of the Kyoto Protocol could lead to substantial increases in electricity costs and rates. Interactions with other regulatory initiatives may lead to additional costs not accounted for by analyses focusing solely on climate change policies. A recent EPRI study, for example, suggests that the relative time tables for implementing the NO_X SIP Call and Kyoto Protocol would lead to premature retirement or reduced utilization of electricity generation units with NO_X control investments (Electric Power Research Institute 2000). Under the current NO_X SIP Call, NO_X pollution control investments would need to be made by 2003. These investments would be made obsolete if the Kyoto Protocol were implemented—only four to five years after the NO_X SIP Call—because CO_2 reductions would lead to collateral reductions in NO_X emissions. Figure 17 shows the electric unit capacity for which emission control investments are projected over the period 2000 to 2012 as well as the eventual utilization of the units over the period 2018 to 2020. The figure also lists the amounts of the overall investments in NO_X and SO_2 controls for the various cases. In the BAU case, most of the units represented in the \$11.6 billion investment in NO_X and SO_2 control necessary to meet NO_X SIP Call and Title IV (Phase II) SO_2 requirements would still be operating in the 2018 to 2020 period. In contrast, if the SO_2 and CO_2 initiatives were put in place, relatively little of the \$3.0 billion investment in NO_X pollution control would be operating in the 2018 to 2020 period. No additional investment in SO_2 is necessary under the Kyoto targets due to collateral SO_2 reductions from CO_2 policies.

Figure 18 shows EIA estimates of the electricity rate effects of the Kyoto Protocol in 2005, 2010, and 2020. (These results assume Annex I trading, i.e., a domestic U.S. CO_2 target equal to 9 percent above 1990 level.) Compliance with Kyoto would raise the electricity price in 2010, for example, by 3.0 cents per kilowatt-hour, from 6.0 cents per kilowatt-hour to 9.0 cents per kilowatt-hour, an increase of 50 percent. The rate effects of the Kyoto Protocol would be substantially different under other assumptions regarding international GHG trading. The EIA estimates that the impact of the Kyoto Protocol on 2020 electricity prices would be 1.7 cents per kilowatt-hour under full international trading, and 3.4 cents per kilowatt-hour under no international trading.

Figure 17. Amount and Fate of Emission Control Retrofits for SO_2 and NO_X Cap Compliance under CO_2, SO_2, and NO_X Policies and Business-As-Usual



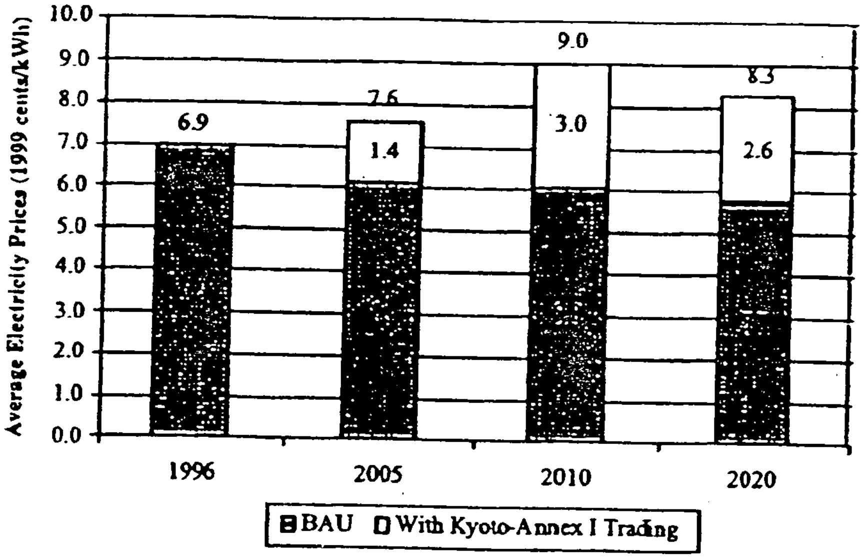
B = BAU C = Current policy direction G = 2030 carbon glide path

All but 6-10 GW of capacity is at coal-fired units. All scenarios include the NO_X SIP Call. The Current Policy Direction also includes the Kyoto Protocol (U.S. domestic emissions at 1990 + 9 percent levels with Annex I trading), the NO_X SIP Call, and a 50 percent reduction in SO_2 from Title IV Phase II levels. The "2030 Carbon Glide Path" uses more gradual CO_2 emission reductions while maintaining the same cumulative CO_2 emissions as the Current Policy Direction.
Source: Electric Power Research Institute 2000.

The Appendix to this report provides additional information on the impact of the Kyoto Protocol on the electric utility sector and other economic conditions. The following areas are discussed:

1. Fuel utilization;
2. Energy prices and expenditures;
3. Overall U.S. economic performance; and
4. Regional economic differences.

Figure 18. Electricity Prices under Business-As-Usual and the Kyoto Protocol



Updated to 1999 dollars.
Source: U.S. Department of Energy 1998b.

C. Water Quality

Regulations related to water quality can have substantial impacts on individual electric power facilities. This section considers the impacts of three water quality programs:

1. Water Quality Standards and Criteria Development and Implementation;
2. Total Maximum Daily Loads (TMDLs); and
3. Requirements related to Cooling Water Intake Structures (CWIS).

1. Water Quality Standards, Criteria Development, and Implementation

The Federal Water Pollution Control Act (known as the Clean Water Act) is the primary means for regulating surface water pollution in the U.S. The Clean Water Act (CWA) requires that virtually all entities obtain a permit before discharging pollutants into navigable waters from a specific source. The permit program, or National Permit Discharge Elimination System (NPDES) program regulates discharges of pollutants into surface waters. The CWA allows states to manage this program, if approved by EPA. The resulting NPDES permitting program bases its limits on industry-specific effluent guidelines and the development and implementation of water quality standards developed by each state.

a. Policy Overview

In issuing NPDES permits, the appropriate regulatory authority is required to impose effluent discharge limitations necessary to ensure state water quality standards are maintained. Water quality standards consist of two parts. First, states must designate certain beneficial "uses" for each water body. Second, regulators must develop water quality "criteria" necessary to protect the beneficial uses. (These criteria include maximum concentrations of water pollutants.) Therefore, water quality standards serve two purposes. They establish the water goals for a specific waterbody, and they serve as the basis for water quality-based treatment controls and strategies beyond the minimum technology-based levels of treatment.

Since the passage of the CWA, many refinements have been made to the supporting documentation defining the fundamental components of water quality criteria. In addition, amendments to the CWA and regional initiatives have pushed the boundaries of "water quality-based permitting." They have added significant complexity to issues such as the limits of analytical methods, definition and measurement methods for concepts such as "toxicity" and "bioaccumulation factor," and improved knowledge on the fate and transport of particular pollutants. These refinements have had the effect of refocusing the permitting program from a technology-based program to a more sophisticated program based on water quality, a program which could be more difficult to assess and administer.

b. Policy Impact

These changes mean that point source dischargers now are faced with more restrictive effluent limitations in their permits. More pollutants will be addressed, lower limits will be required, and mechanisms for flexibility in meeting these limits will be reduced. This increases the cost of compliance, the administrative costs of assuring that compliance, and the legal costs associated with permit negotiations. These increased costs could affect fuel choice and energy prices and could raise energy supply concerns.

2. *Total Maximum Daily Load Program*

A major component in future water quality-based permit limitations will be the Total Maximum Daily Load (TMDL) program. A TMDL is the amount of a pollutant a water body can assimilate and still maintain applicable standards. To ensure that water quality standards are attained, TMDLs can result in effluent standards that are more stringent than technology-based standards for specific individual sources, categories of point sources, or non-point sources. TMDLs must be developed for all individual pollutants that may adversely affect the attainment of water quality standards.

a. Policy Overview

The TMDL process is mandated by the CWA to address situations involving water bodies that do not currently meet applicable water quality standards. The CWA creates a mechanism for the review of water quality limited water bodies to determine whether more stringent permit conditions may be required. The TMDL process establishes a link between individual water body water quality assessments and water quality-based permit actions.

The EPA has recently revised the current regulatory requirements for establishing TMDLs under the Clean Water Act. The rule is effective in October 2001. The new rule modifies and expands the requirements for the development and implementation of a TMDL. The revisions detail the required elements of TMDL plans, including allocations of wasteloads to all point and non-point load sources. More stringent TMDLs could potentially affect all sources, including electric generation facilities located on or near impaired waterways. There are currently 20,000 impaired water bodies and this number is expected to double as a result of the new regulation.

b. Policy Impact

The focus on TMDLs may result in more stringent pollutant discharge limits as a result of water quality-based permitting. Indeed, contributions from airborne pollutants must be considered when setting a TMDL. Therefore, more stringent limits on air emissions may result, particularly for mercury and NO_x. There may be limitations on economic growth on or near impaired waterways as a result of the TMDL program. While it is difficult to estimate the costs of compliance with permit limitations that may result from TMDLs, anecdotal evidence for contaminants of concern (e.g., mercury) suggests that compliance costs for some plants could exceed $100 million.

State water pollution control administrators have estimated that the average cost of calculating TMDLs for the current backlog of 40,000 TMDLs is in the range of $13–$23 million per state. It is expected that more than 80,000 TMDLs will need to be calculated as a result of the recent EPA regulations.

3. *Cooling Water Intake Structure Regulations*

Section 316(b) of the CWA requires that the best technology available (BTA) for minimizing adverse environmental impacts applies to the location, design, construction, and capacity of any cooling water intake structure such as those used by power generation facilities. Steam electric power plants use more water for cooling purposes than any other industrial use. Power plants use water to cool the steam that turns turbines to generate electrical energy. In 1993, EPA announced its plans to develop new Section 316(b) rules, which sparked a debate over the actions that would be necessary. The debate centers around what necessary or appropriate action is needed to minimize adverse environmental impacts to affected aquatic populations as a direct result of the cooling water intake structure. In the end, generation facilities could be faced with requirements to retrofit costly technologies following strict location and design criteria.

a. Policy Overview

No § 316(b) rules currently exist, although a substantial body of guidance, administrative precedent, and case law have shaped the implementation of § 316(b) on a case-by-case basis for the past 25 years. EPA attempted to establish § 316(b) rules in the 1970s. These rules were challenged on procedural grounds and suspended. Since then, state and federal permit writers have implemented § 316(b) on a case-by-case basis as a part of permit renewals.

EPA is currently in the process of developing § 316(b) regulations. These renewed efforts to develop rules were prompted by a consent decree signed by EPA as a result of a lawsuit filed in 1995 (*Cronin v. Browner*, 898 F. Supp. 1052, S.D.N.Y.) by environmental groups seeking to compel EPA to issue regulations under § 316(b). EPA agreed to a rulemaking schedule to issue proposed regulations by July 2, 1999 and to promulgate final § 316(b) regulations by July 1, 2001. EPA was not able to meet the original deadline for filing proposed § 316(b) regulations, but has extended the deadline (U.S. Environmental Protection Agency 1999d). In 1999, the EPA filed a motion to bifurcate the rulemaking into two phases, one addressing new facilities and the other addressing existing facilities. These two phases would have separate schedules, with final action on both phases to be completed by April 1, 2004. EPA recently promulgated proposed regulations for new facilities (65 Fed. Reg. 49060).

b. Policy Impact

The existing § 316(b) determinations by EPA and authorized state permitting agencies have required owners of plants with CWISs to undertake a variety of measures, including changes to intake structures, retrofits of units with closed-cycle cooling towers, mitigation activities (e.g., fish ladders and wetlands restoration), and monitoring programs. The forthcoming EPA § 316(b) guidelines could significantly change the outcomes of future determinations if they adopt "one-size fits all" technology requirements and burdensome study requirements.

The EPA proposal for new facilities would establish national requirements based primarily on the location of the facility. A major concern among utilities and other owners of facilities subject to § 316(b) requirements is that the proposed regulations set performance criteria that can only be met by recirculating cooling systems (i.e., cooling towers). Moreover, the proposed rule would set a dangerous precedent for existing facilities. Several studies have estimated the potential national costs of requiring these retrofits (Stone and Webster 1992, Veil 1993, Veil et al. 1993).[25] The costs can be viewed as an upper bound to the potential costs under § 316(b), because cooling towers are typically one of the most costly alternatives available to reduce organism losses and may not be suitable as BTA. Nevertheless, it is useful to document these costs as an indication of the costs that might be incurred and the changes in fuel mix that might result.

Installation of cooling towers results in two major types of costs. The first type of cost relates to the cooling towers themselves, including the capital cost of installing the retrofit (which can exceed $500 million in 1999 dollars) and the additional costs of operation and maintenance. The second kind of cost results from the losses of energy and capacity due to turbine back pressure (which makes turbines operate less efficiently) as well as the auxiliary power requirements of the cooling towers. The size of the power losses range from 1.1 to 4.6 percent of the rated capacity at fossil-fuel units and from 1.0 to 5.8 percent at nuclear units (Veil et al. 1993).

25 These studies were developed in the context of a proposed legislative change that would have removed the variance under Section 316(a) and thus potentially required closed-cycle cooling.

Table 7 provides estimates of the potential costs of retrofitting electricity plants with closed-cycle cooling towers based upon two studies, one by Stone and Webster (1992), and one by Argonne researchers (reported in two documents, Veil et al. 1993, Veil 1993). As of 1993, both studies reported that 189,000 megawatts of power from 679 plants had CWIS. The two studies provide similar overall results for the present value of costs of retrofitting these 679 plants with closed-cycle cooling towers. The overall costs (translated into 1999 dollars) are $45.9 billion according to the Stone and Webster study, and between $40.4 billion and $54.8 billion according to the Argonne study. The annualized total cost of these cooling towers over 20 years would be $4.3 to $5.2 billion per year.[26]

A requirement to retrofit plants with closed-cycle cooling towers could have two types of impacts on the electricity fuel mix:

1. *Replacement power for energy/capacity losses*—Energy and capacity penalties from cooling tower operation would require additional generation from other plants to replace those losses.
2. *Replacement power for premature retirement*—Given the potential costs of adding cooling towers, some facilities are likely to retire rather than install cooling towers. To the extent this option is exercised, additional generation would be required to replace the capacity lost.

The two studies did not assess fuel mix impacts. (The studies do note the potential energy/capacity losses involved, as reported in Table 7.) It seems clear, however, that the bulk of the facilities that face potential § 316(b) regulatory requirements are large coal-fired and nuclear units. As of 1993, 146,000 megawatts of fossil-fired generation and 43,000

Table 7. Present Value of Costs of Retrofitting Existing Electric Utility CWIS with Closed-Cycle Cooling Towers

			Replacement Energy and Power		*Cooling Tower*		
Study	*Lost Energy (billion kWh)*	*Lost Capacity (MW)*	*Total Energy Costs ($billion)*	*Total Capacity Costs ($billion)*	*Total Capital Costs ($billion)*	*Total O & M ($billion)*	*Total Cost ($billion)*
Stone and Webster	—	8,842	$11.4	$2.5	$30.3	$1.7	$45.9
Argonne	14.7–23.7	3,050–4,940	$13.0–21.0	$1.6–6.0	$25.9–27.8	—	$40.4–54.8

Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999).

Source: Stone and Webster 1992; Argonne results from Veil et al. 1993 and Veil 1993.

26 Assuming an interest rate of 7 percent.

megawatts of nuclear generation had CWIS structures, making them potential candidates for the cooling tower installation requirements. The large majority of potentially affected fossil-fueled units are coal-fired units.[27] In contrast, combined-cycle gas units, hydroelectric facilities, and some renewable technologies (e.g., solar and wind) do not utilize CWIS, and would not be affected by a § 316(b) rulemaking.

D. Waste Disposal

Various programs regulate the disposal of wastes from power plants. This section considers two major programs:

1. Solid and hazardous waste regulations under the Resource Conservation and Recovery Act (RCRA);
2. Nuclear waste regulations established by the Nuclear Regulatory Commission.

1. *Solid and Hazardous Waste Regulations*

RCRA requires the EPA to set standards for the handling, shipping, and disposal of solid and hazardous wastes. These regulations apply to certain wastes generated by electric power facilities. In most cases, the EPA has delegated the authority to implement the waste regulations to state regulatory authorities.

a. Policy Overview

The primary wastes from electric generation facilities include high-volume wastes—wastes from the combustion of fossil fuels—and low-volume wastes, such as boiler cleaning chemicals, boiler blow-down, used oil, and degreasers. Management of these wastes is prescribed in the RCRA rules, which determine whether wastes must be handled according to less stringent solid waste regulations or significantly more stringent hazardous waste rules. All types of electric facilities generate low-volume wastes. Current regulations allow low-volume wastes associated with fossil fuel combustion to be treated as non-hazardous wastes and co-managed with high-volume wastes.

The principal high-volume waste of consequence is ash from coal-fired facilities. Regulation of this ash is currently covered by the Bevill Amendment to RCRA, which exempts high-volume wastes from hazardous waste regulations as long as coal is the primary fuel burned (i.e., more than 50 percent) (58 *Federal Register* 42466 1993). This exemption allows coal-fired units to co-fire with other fuels (e.g., tires, contaminated soils, and used oil) without the risk that ash would be designated as a hazardous waste.

27 Veil 1993 surveys 20 percent of the potentially affected fossil-fired units. Of the surveyed units, 81 percent were coal units, with the remaining gas, oil, or co-fired gas/oil units.

On April 25, 2000, the EPA announced that it would not regulate combustion wastes as hazardous wastes under Subtitle C of RCRA, thus extending the exemption under the Bevill Amendment (FR 65 32214). The EPA stated that it might reconsider this determination based on the evaluation of new scientific information, as it becomes available. At the same time, the EPA plans to develop national standards to address combustion wastes from coal-fired units that are presently either disposed in landfills or surface impoundments or used in minefill applications under Subtitle D of RCRA (65 *Federal Register* 32214 and 32231, respectively). These standards may lead to changes in regulatory requirements for coal combustion waste management from current state regulations.

b. Policy Impact

With the exception of coal-fired facilities and nuclear facilities, which are addressed later, waste streams from generation facilities using other types of fuel are relatively similar. These facilities primarily generate low-volume wastes that, for the most part, are non-hazardous and can be managed on-site and with methods that do not have to meet more costly hazardous waste disposal standards. Coal ash is a relatively significant waste stream, although disposal currently does not have to meet hazardous waste standards under the recent EPA determination. The cost of disposal of these wastes under the standards to be developed under Subtitle D of RCRA would depend upon the stringency of those standards. More stringent standards could impose some constraints and potential additional costs on coal-fired facilities.

2. *Nuclear Waste*

Radioactive waste is a natural product of electricity generation at nuclear power plants. Numerous regulations exist to ensure that individuals working at nuclear plants and living in proximity to such plants are not exposed to unsafe radioactivity.

a. Policy Overview

Nuclear power plants produce wastes of varying levels of radioactivity. The Nuclear Regulatory Commission (NRC) is responsible for all aspects of managing these wastes, including safe disposal of nuclear waste and proper management during transportation and storage. Numerous NRC regulations concerning the generation, handling, and disposal of such wastes have been developed. Other agencies, including the Department of Energy (DOE) and the Department of Transportation (DOT), also are involved in the nuclear waste management process.

Probably the most important and least resolved issue in nuclear waste management is the siting of nuclear waste disposal facilities. Facilities must be sited for two kinds of waste:

- *Low-level waste*—This category includes wastes that are relatively low in radioactivity and have a short half-life. These wastes are currently regulated at the state level, although the NRC develops guidelines to ensure proper transport and storage of these wastes and licenses disposal facilities.

- *High-level waste*—This category primarily includes spent fuel rods containing short-lived fission products and long-lived radionuclides. High-level wastes must be disposed of in accordance with NRC policies that require higher levels of care and protection than low-level wastes.

To manage low-level wastes, states have entered into agreements to package and transport wastes to the two NRC-licensed disposal facilities in the U.S. Although low-level wastes generated at nuclear plants have been declining in quantity in the past decade, a shortage of disposal facilities has caused many plants to store their wastes on-site for longer than expected (U.S. Nuclear Regulatory Commission 1998, Holt 1996).

The management of high-level nuclear wastes is controlled by the Nuclear Waste Policy Act (NWPA) of 1982. The NWPA requires the DOE to select and develop a permanent repository for high-level wastes. The DOE currently is studying the suitability of Nevada's Yucca Mountain as a high-level waste repository. On August 6, 1999, the DOE issued a draft Environmental Impact Statement (EIS) that assesses the prospects for developing a permanent repository at Yucca Mountain and the impact of transporting high-level wastes to the repository. It is becoming increasingly unlikely that the Yucca Mountain facility will be able to accept wastes by the mandated opening date in 2010 (Holt 1998).

The current status of nuclear waste disposal can be summarized as follows (Holt 1998):

- *Current on-site storage*—Until spent fuel can be shipped to an off-site storage facility, it is stored on-site in pools of water that are beginning to reach their maximum storage capacities at many facilities. Thus, there is a growing need for the spent fuel to be stored at a permanent or off-site repository.
- *Interim storage*—As on-site storage has begun to reach capacity, many utilities have called for the DOE to build an interim storage facility until a permanent one opens. Development of such a repository in the Skull Valley Reservation is being considered.
- *Permanent repository*—The siting of this facility has been a slow process. After a long selection process the Yucca Mountain site was chosen, although many still oppose this choice. The process of testing and developing the Yucca Mountain site has been slowed by many factors.

b. Policy Impact

The eventual cost of proper disposal of nuclear wastes will be substantial for most nuclear facilities. To support the DOE's current siting efforts, utilities that own nuclear plants are required to pay annual fees to the Nuclear Waste Fund. Currently, the fee is equal to one-tenth of a cent per kilowatt-hour generated by nuclear power. As of the end of the 1995 fiscal year, the fees and interest totaled approximately $14 billion, although this total is likely to be a fraction of the eventual costs (Nuclear Energy Institute 1999).

Delays in the opening of a final high-level waste repository and shortages in low-level waste disposal facilities may impose several costs on utilities that own nuclear units. Access to waste disposal sites may become more expensive or unavailable in the future. On-site storage facilities would need to be expanded, and continued on-site management would impose additional costs. Siting of interim storage facilities, if developed, also would represent an additional cost. Extending lives beyond current nuclear retirement dates would increase generation of low-level and high-level wastes and thus potentially add to the costs of waste disposal. These added costs could affect electric utility decisions to relicense or continue to operate nuclear power facilities.

E. Energy Policies

This section considers many energy policies, other than restructuring, that are likely to have substantial effects on electric power fuel use. We consider the following policies in this category:

1. Hydro relicensing;
2. Nuclear relicensing;
3. Renewable energy policies;
4. Power plant siting requirements;
5. Natural gas facility siting requirements;
6. Oil and gas drilling constraints.

1. Hydro Relicensing

Hydropower is the largest source of renewable energy in the U.S., with a summer capacity of 77,650 megawatts in 1997 (U.S. Department of Energy 1998a). This 1997 value represents more than a doubling of the 1960 capacity of 33,300 megawatts. Almost no new hydroelectric capacity is anticipated in the next several decades because of various factors, including increased regulatory hurdles and expenses, uncertainty over the success of license approval, and competition from other technologies (U.S. Department of Energy 1998a, Hunt and Hunt 1997).[28] Indeed, many existing facilities will need to undergo relicensing over the next decades in order to continue operation. Failure to relicense these facilities and/or imposition of operational constraints on power generation as a result of relicensing may reduce the contribution of hydroelectric power. This section focuses on the policies affecting these relicensing decisions.

a. Policy Overview

The Federal Power Act (FPA) requires virtually all hydroelectric facilities to be licensed by the Federal Energy Regulatory Commission (FERC). After the expiration of

28 The Annual Energy Outlook 1999 forecasts hydropower capacity of 78.51 thousand megawatts in 2020, only 0.91 thousand megawatts, 1.2 percent, greater than 1997 levels.

initial license, which runs for up to 50 years, the facility must be relicensed in order to continue generating power. The process for relicensing existing facilities is essentially the same as the process for an initial license. Relicensing applications must be submitted five years in advance of the original license's expiration date.

The licensing process has undergone substantial changes over the years. The most recent significant changes occurred with the Electric Consumers Protection Act (ECPA) of 1986, which amended the FPA. These amendments required FERC to do the following:[29]

- Give equal consideration to development (e.g., electricity and flood control), and non-development (e.g., habitat and fish), values;
- Attach conditions to licenses that would mitigate or protect wildlife and fish populations affected by the facility;
- Base these conditions on recommendations from federal and state wildlife agencies, unless FERC determines that they are inconsistent with the law;
- Provide an explanation for rejecting any recommendations;
- Attempt to resolve inconsistencies between recommendations.

Other legislation, such as the Clean Water Act (Section 401) and the Endangered Species Act, has increased the number of agencies participating in relicensing decisions. Recent FERC rules have attempted to address problems and delays caused by the increased complexity of the licensing process.[30]

b. Policy Impact

A total of 239 hydro facility licenses will expire between 1997 and 2020 (Hunt and Hunt 1997), and they must undergo relicensing in order to continue operation. These facilities have a total capacity of 19,489 MW, about 26 percent of all hydroelectric capacity.[31] When original licenses were granted, there were few environmental laws placing requirements on facilities. As noted, facilities coming up for relicensing must comply with more recent environmental laws that impose new constraints on operations. The additional costs and constraints include the following:

- *Environmental Impact Statements*—License applications must now include a detailed EIS, which can be costly to prepare.

29 See U.S. General Accounting Office 1992 for a detailed description of the factors affecting future hydroelectric capacity.

30 For example, more recent rules combine the pre-filing consultation process and environmental review process in an effort to reduce the length of time required to complete the relicensing (18 Code of Federal Regulations Parts 4 and 375 1997).

31 An additional 2,728 MW of capacity had pending relicense applications as of the 1997 Hunt and Hunt report.

- *Environmental mitigation*—Renewed licenses may include requirements that certain environmental mitigation activities be performed to reduce facility impact. These activities include installation of fish passage devices, improvements in fish habitats, stocking of fish species, and other fish protection measures.
- *Changes in generation and capacity*—The new license may require increases or decreases in allowable capacity and generation. Increases may occur because of improvements in turbine efficiency or because limits originally may have been determined by local demand rather than facility capacity. Decreases may occur due to environmental restrictions on when and how much flow the facility must produce.[32] These conditions may change both the aggregate quantity of power that can be generated and the flexibility to provide power during peak periods.

Passage of the ECPA has increased the level of input from agencies outside of FERC in relicensing decisions, leading to large numbers of changes in the relicensing process (U.S. General Accounting Office 1992). The current process of relicensing typically is longer and more expensive than it was before ECPA, and frequently imposes more operational constraints on hydroelectric units. From 1994 to 1996, relicenses were processed in about 4.5 years on average, compared to less than three years on average over 1986 to 1988 (Hunt and Hunt 1997). The actual role of these non-FERC agencies continues to evolve over time, making the outcome of future relicensing decisions difficult to predict. The following relicensing decisions provide some perspective on the current issues:

- *Tacoma or Jefferson County case*—In 1994, the Supreme Court held that state water quality agencies could, acting under the authority granted in the Clean Water Act, force hydroelectric facilities to accept water flow or quantity conditions necessary to maintain water quality standards. This is the first instance in which state resource agencies imposed conditions rather than making recommendations in relicensing decisions.
- *Cushman case*—FERC recently approved a license for the Cushman Hydroelectric Project that would impose significant restrictions on operations, leading to economic losses of $2.5 million a year according to FERC estimates. The electric utility maintains that these losses run counter to the Federal Power Act, which requires that licenses be issued on "reasonable terms" (Federal Power Act, Section 15).
- *Eugene case*—The 1997 relicensing of two dams owned by the Eugene Water & Electric Board has been appealed for a number of different reasons, including FERC's authority over wildlife and other environmental issues and the baseline used to measure fish benefits. The latter dispute is over the use of a baseline based on "natural" conditions (i.e., conditions without the plant operating) in estimating the impacts of hydropower operations.

32 These conditions include increased minimum bypass flows, water releases for fish passage facilities, restrictions on reservoir fluctuation, and limits on downstream flow release fluctuations.

- *Edwards case*—In 1999, FERC ordered the dismantling of the Edwards Dam on the Kennebec River, the first time that FERC has required dismantling of a dam over the objections of its owners. Dams in other areas have been dismantled, but always with the agreement of the owner.

These examples suggest that the effects of FERC policy and the recommendations of outside agencies on the fate of hydroelectric relicensing are unsettled.

Given the significant uncertainty over these policy decisions, the impact of relicensing requirements on hydroelectric power generation is difficult to predict. A recent study commissioned by the Department of Energy (Hunt and Hunt 1997), provides some insight into the potential magnitude of the impact. Table 8 summarizes the impact and costs to the electric power sector for hydroelectric relicensing over the historical period of 1980 to 1996 and for a projected period from 1997 to 2010. The historical period is divided into the period before ECPA (1980 to 1986), and the period after ECPA (1987 to 1996).

Table 8. Impact of Hydroelectric Relicensing

	Pre-ECPA (1980–1986)	*Post-ECPA (1987–1996)*	*Projected[1] (1997–2010)*
LICENSES EXPIRING			
Capacity (MW)	3,256	3,238	22,217
Plants	63	163	520
Percent of Total 1995 Capacity	4%	4%	30%
COSTS (MILLION $1999)			
License Processing	$175	$233	$1,125
Lost Peaking Capacity	$0	$250	$1,576
Lost Generation	$43	$550	$4,493
Mitigation Measures	$539	$1,205	$5,150
Total Costs	$756	$2,238	$12,345
ELECTRIC SYSTEM IMPACTS			
Peaking Capacity Loss (MW)	0	104	166
Percent of relicensed peaking capacity	0.0%	5.6%	5.0%
Generation Loss (million kWh/yr)	65	681	5,300
Percent of licensed generation	0.6%	5.0%	5.9%

[1] Includes pending relicense applications as of 1997.

Historical estimates include lost capacity from surrendered licenses. Many surrenders are from licensed facilities that were never constructed. The value of lost generation from surrendered units is based on average utilization and prices for existing facilities. Costs are in 1999 dollars, adjusted from reported dollars using the GDP deflator (U.S. Department of Commerce 1999). Capacity and generation costs are based on the costs over 30 years. The report does not state whether costs are discounted.

Source: Hunt and Hunt 1997.

Changes in the relicensing process and resulting determinations due to ECPA have impacted hydroelectric power generation (Hunt and Hunt 1997):

- *Increased peaking capacity losses*—While no capacity losses were experienced in the seven years prior to ECPA, 104 megawatts of peaking capacity, 5.6 percent of total, have been lost in the ten years since ECPA. The estimated value of these peaking capacity losses is $250 million.
- *Increased generation losses*—Losses in power generation increased from 65 million kilowatt-hours, 0.6 percent of relicensed generation, to 681 million kilowatt-hours, 5.0 percent of relicensed generation, after the passage of ECPA. The value of these generation losses over 30 years after relicensing has increased from $43 million to $550 million, a more than twelve-fold increase, since ECPA.
- *Increased mitigation measures*—The cost of environmental mitigation measures increased from $539 million, $166,000 per megawatt, to $1,205 million, $372,000 per megawatt, after ECPA.
- *Increased license processing fees*—Average license processing fees across all facility sizes have increased from $54,000 per megawatt to $71,960 per megawatt. The processing fee per megawatt varies with the facility size. Since the post-ECPA units contain more small facilities, which have higher costs per megawatt, the increase in costs across all facilities actually understates the increase in relicensing costs for a particular sized facility.

The cumulative cost of all of these factors has increased from $756 million over the seven years previous to ECPA to $2,238 million in the ten years since the passage of ECPA. These trends suggest that environmental conditions required under relicensing have had an increased impact on generation and capacity levels since the passage of the ECPA.

Hunt and Hunt forecast the impacts of future relicensing decisions over the period 1997 through 2010 based on extrapolating the outcomes from recent relicensing decisions to future relicensing decisions.[33] These estimates do not account for potential future changes in FERC policies or the role of non-FERC agencies. The forecast of loss of peak capacity is about 166 MW, while the forecast of loss of generation is about 5.3 gigawatt hours per year. Total costs are forecast to be almost $12.3 billion, with environmental mitigation measures of $5.2 billion and lost generation of $4.5 billion comprising almost 80 percent of these costs.

2. Nuclear Relicensing

Nuclear power currently provides about 19 percent of electric power in the U.S., second in magnitude only to coal-fired generation. The initial operating licenses granted to many existing nuclear units will expire over the next decade. These units will cease to produce electricity unless they successfully apply to have their licenses extended.

33 Projected costs are based on a regression of costs over the period 1994 to 1996, and lost capacity and generation estimates based on data from 1987 to 1996.

a. Policy Overview

There were 105 nuclear generation units in the U.S. as of 1998 (Nuclear Energy Institute 1999). The initial operating licenses were for 40 years. When these licenses expire, operators have the option to renew the license for an additional 20 years. Renewal applications have two principal components (U.S. Nuclear Regulatory Commission 1999a):

1. *Integrated plant assessment*—This assessment identifies and lists structures and components subject to an aging management review (AMR). These structures and components undergo substantial analyses to insure safe and reliable operation. If necessary, some structures and components may be replaced.
2. *Environmental review*—This review analyzes the impact of an extension of the plant's operation on the environment.

Applications must be submitted at least five years in advance of the license expiration to ensure sufficient time to conduct an adequate review.

b. Policy Impact

On March 23, 2000, the Calvert Cliffs Nuclear Power Plant became the first plant to achieve license renewal. The approval process took 22 months from the time the license renewal application was filed with the NRC. The NRC has also received applications from three other plants: Oconee Nuclear Station, Arkansas Nuclear, and Edwin I. Hatch. A large number of additional applications are anticipated, with the NRC reporting future submissions for 14 additional plants over the period 2000 to 2003. Licenses for about 10 percent of the nuclear facilities will expire by 2010, and 40 percent will expire by 2015 (U.S. Nuclear Regulatory Commission 1999a). Many of these nuclear facilities are applying for license renewal far in advance of the expiration of their existing licenses.

The failure to relicense these facilities would mean that nuclear capacity and generation would be replaced with other technologies. An EIA report examines cases with different levels of nuclear power generation (U.S. Department of Energy 1998a). By comparing these cases, the proportion of lost nuclear power made up by the other power technologies can be determined. Based on these EIA cases, Table 9 shows the mix of fuels that would make up for a decrease in nuclear generation in 2010. Virtually all of the compensating generation would come from a combination of natural gas, 67 percent, and coal, 23 percent.

Nuclear retirements for non-economic reasons also would tend to increase electricity rates. The EIA report noted above does not provide estimates of the potential rate increases.

3. Renewable Energy Policies

Non-hydroelectric renewable energy sources currently make up less than 2 percent of U.S. electric power generation. Over the next 20 years, the EIA projects that non-hydroelectric renewable capacity will rise from 11.59 thousand megawatts in 2000 to 18.17 thousand megawatts in 2020 under BAU conditions (U.S. Department of Energy 1998a).

Table 9. Increase in Generation from Other Fuel Types Due to Loss of Nuclear Capacity in 2010 (Percent of Total Increase)

Fuel Type	*Generation Increase*
Coal	23%
Natural Gas	67%
Petroleum	10%
Renewables	0%
Total	100%

These results assume the implementation of no additional environmental policies, such as CO_2 constraints, additional SO_2 reductions, or the NO_X SIP Call. The figures are derived by taking generation differences between the high and low nuclear cases in 2010.

Source: U.S. Department of Energy 1999b.

Restructuring of the electric power industry has led to concerns that the continued development of renewable energy resources will be hampered by the new competitive environment (Nogee et al. 1999, U.S. Department of Energy 1998a).

In response to these changes and concerns about the future of renewable energy, a number of policies have been proposed to encourage the continued development of renewable energy resources. This section considers several policies to expand renewables, including:

- Renewable Portfolio Standards;
- "Green" pricing;
- Net metering; and
- Tax credits.

a. Renewable Portfolio Standards

(1) Policy Overview

The basic mechanism of a Renewable Portfolio Standard (RPS) is the requirement that renewable energy resources generate a minimum level of energy. These proposals typically target non-hydroelectric renewable resources, although some include hydroelectric resources. While following this basic model, RPS policies and proposals differ along several dimensions.

- *Targeting specific types of renewable resources*—Particular types of resources (e.g., solar or biomass) may have individual targets, or classes of resources may have different targets.
- *Changing targets*—Percent targets may increase or decrease over time.

- *Policy termination*—Targets may be phased out after some date, on the assumption that the market stimulus is no longer necessary to develop the technology.
- *Renewable credit trading*—Many programs/proposals allow electric companies to trade their obligations to utilize renewable power. Utilities not generating the required portion of renewable electricity can purchase renewable electricity credits from another electric company that generated electricity with renewable resources in excess of the required quantity.
- *Capping of costs*—Many programs/proposals include a "cost cap" (i.e., a maximum cost in cents per kilowatt-hour), to limit the cost of complying with the RPS.

Many states have adopted an RPS and some federal electric power restructuring proposals include one. The following examples provide a range of the requirements included in recent state initiatives (U.S. Department of Energy 1998a):

- Connecticut breaks resources into two classes:
  - Class 1—Includes sustainable biomass, fuel cells, landfill gas, solar, and wind power.
  - Class 2—Includes other biomass, municipal solid waste, and conventional hydroelectricity.

The program requires that by 2001, Class 1 resources must provide a minimum of 0.75 percent of output, and Class 1 and Class 2 resources must combine to provide 5.5 percent. By 2009, the Class 1 requirement grows to 6 percent, and an additional 7 percent must be met by a mix of Class 1 and 2 resources.

- Massachusetts requires that 1 percent of sales come from qualified energy sources by 2003 and 15 percent by 2020. Qualified sources include biomass, landfill gas, fuel cells, conventional hydroelectricity, ocean, thermal, and wind power.
- Maine requires that by March 2001, 30 percent of total retail sales be from biomass, fuel cells, geothermal, small hydroelectric, municipal solid waste, solar, or wind.
- Texas requires 2,000 megawatts of new renewable capacity, including hydro, by the year 2009, with intermediate targets in 2003 of 400 megawatts, 2005 of 900 megawatts, and 2007 of 1,400 megawatts.

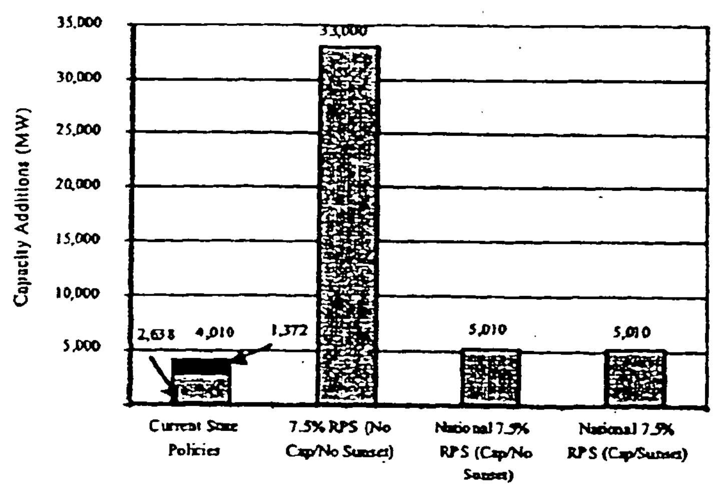
Various federal restructuring bills have RPS targets ranging from 4 to 10 percent of sales in 2010 and 10 to 20 percent in 2020. Many do not specify requirements as far out as 2020 (U.S. Department of Energy 1998a, Nogee et al. 1999). Indeed, many of the federal proposals have sunset provisions in which requirements expire after a given time.

(2) Policy Impact

The impact of RPS policies depends greatly upon their details, including the type of renewable resources targeted, the flexibility available to utilize least-cost renewable resources, the presence of a cost cap, and the timing. The impact on non-renewable resources depends on what types of renewable resources are encouraged and whether they provide peak or off-peak power.

Figure 19 summarizes the EIA's estimates of the effects of current state programs and a national 7.5 percent RPS on renewable capacity additions by 2010 (U.S. Department of Energy 1998a, U.S. Department of Energy 1999b). Approved state RPS programs are projected to increase renewable capacity by 2,638 megawatts between 1999 and 2011, with the Texas RPS accounting for the majority of this total—2,000 megawatts.[34] The EIA also estimated that, as of 1998, state mandates and other requirements likely would contribute an additional 1,372 megawatts of renewable capacity.[35] The combined effect of these state initiatives would be 4,010 megawatts of additional renewable power sources. As Figure 19 indicates, a federal mandate is projected to have a substantially greater effect on renewable

Figure 19. Estimated Renewable Capacity Additions by 2010 Due to State Policies and National 7.5 Percent RPS



Source: U.S. Department of Energy 1998a, U.S. Department of Energy 1999d.

34 The 2,638 estimate is calculated by adding the EIA's estimate of 638 megawatts of total new capacity resulting from RPS in all states, except Texas, with the 2,000 megawatt RPS in Texas (U.S. Department of Energy 1998a, Texas State Senate Bill 7 1999). The Union of Concerned Scientists analysis of RPS in eight states, not including Texas, projects an additional 2,100 megawatts of renewable resources (Nogee et al. 1999). The EIA estimates that the additional 638 megawatts are comprised of 263 megawatts of wind power, 163 megawatts of solar power, and 137 megawatts of biomass.

35 The EIA does not state what these mandates and requirements are and how they relate to RPS. Its capacity estimate is comprised of 1,017 megawatts of wind power, 149 of geothermal, 137 of biomass, and 69 of landfill gas (U.S. Department of Energy 1998a).

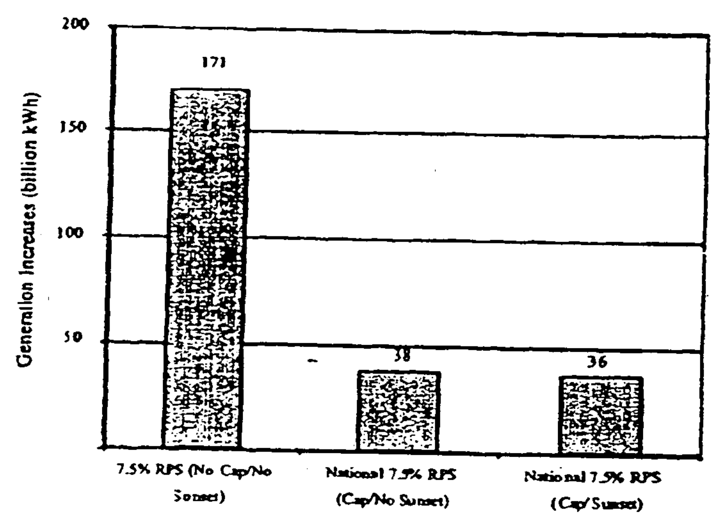
capacity than the current state programs. The federally initiated capacity increase represents more than eight times the increase projected for the existing state regulations.

Figure 20 shows the increases in renewable generation that would occur under a 7.5 percent RPS. The national 7.5 percent RPS analyzed by the EIA includes solar, wind, geothermal, and biomass, thus excluding hydroelectric and municipal solid waste resources. The federal 7.5 percent RPS is projected to lead to nearly 33,000 megawatts of additional renewable capacity beyond state requirements and about 171 billion kilowatt-hours of additional generation, assuming the cost cap does not apply (U.S. Department of Energy 1999b).

As shown in Figures 19 and 20, implementation of the cost cap would significantly reduce the impact of the 7.5 percent RPS. Regardless of whether or not the sunset provision was implemented, only 1 gigawatt of additional renewable capacity would be developed if the cost cap were implemented. The increase in renewable generation from the RPS would be significantly smaller if the cost cap were implemented. Without the cap, renewable generation would increase by 171 billion kilowatt-hours; the increase would drop to 36 or 38 billion kilowatt-hours without the cost cap, depending on whether or not the sunset provision is used[1].

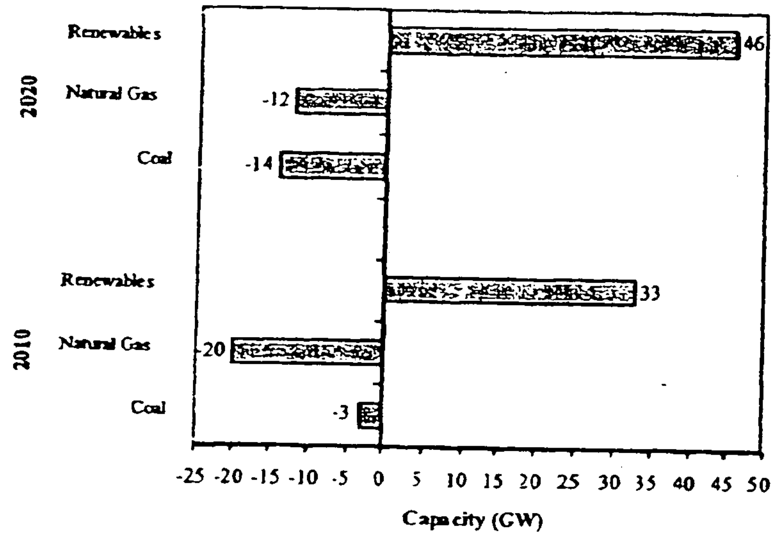
Increases in renewable capacity and generation would be compensated for by decreases for other fuels. Figures 21 and 22 show the EIA projections of the changes in capacity and generation, respectively, in 2010 and 2020 due to the 7.5 percent RPS national requirement with no sunset requirements and no cost cap. The largest impact of the RPS would be on natural gas and coal-fired capacity. In 2010, coal power use is projected to

Figure 20. Estimated Renewable Generation Increases by 2010 Due to State Policies and National 7.5 Percent RPS



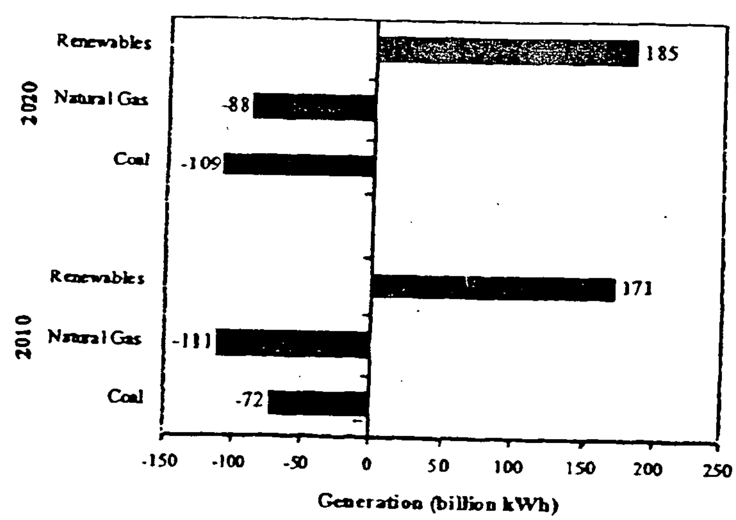
Source: U.S. Department of Energy 1998a, U.S. Department of Energy 1999d.

Figure 21. Changes in Electricity Capacity Due to a National 7.5 Percent RPS in 2010 and 2020



Assumes no cost cap or sunset provisions.
Source: U.S. Department of Energy 1998a.

Figure 22. Changes in Electricity Generation Due to a National 7.5 Percent RPS in 2010 and 2020



Assumes no cost cap or sunset provisions.
Source: U.S. Department of Energy 1998a.

decrease by 3 gigawatts and 72 billion kilowatt-hours, and natural gas is projected to decrease by 20 gigawatts and 111 billion kilowatt-hours. In 2020, the impact on coal use would continue to escalate, while the effects on natural gas use are projected to decrease. In 2020, coal capacity is projected to decrease by 14 gigawatts and 109 billion kilowatt-hours, while natural gas is projected to decrease by 12 gigawatts and 88 billion kilowatt-hours. The impact results primarily from the "crowding out" of non-renewable generation with the increase in renewable generation, although the relative impact across different fuels reflects both the type of generation at the margin and changes in future capacity additions.

Implementation of a 7.5 percent RPS would lead to an increase in electricity prices if utilities were required to use higher-cost renewable energy sources in order to meet the RPS requirements. The EIA estimates that the national 7.5 percent RPS with no sunset requirements and no cost cap would lead to increases in average electricity prices of $1.9 per megawatt-hour in 2010, in 1999 dollars, or about a 3 percent increase (U.S. Department of Energy 1999b). The total impact of this price increase is projected to be $5.8 billion in 2010. The estimated impact on rates declines over time as the renewables are projected to become more competitive with other fuels, due in part to lower costs from the market penetration promoted by the RPS.

The size of electricity price increases would depend in part on the cost of developing new supplies of fuel for biomass generation. Current biomass power generation relies primarily on wood waste for feedstock, although expansion of biomass generation to achieve a 5 percent national RPS (or to achieve anticipated levels to meet the Kyoto targets) would require development of a significant market in agriculture and forest crops devoted to biomass production. Factors that may affect development of such markets include time lags in production of woody crops with three to six year rotations, farmer perception of the risk of new crop markets, and development of financial and contracting arrangements (Electric Power Research Institute 2000). The increased competition for land generated by demand for biomass crops also may lead to food price increases (Electric Power Research Institute 2000, Walsh et al. 1998).

b. Green Pricing and Marketing

(1) Policy Overview

Green pricing and marketing allow consumers to voluntarily support the development of renewable energy resources through their electric power payments.[36] "Green" pricing refers to programs run by regulated electric companies that allow consumers to encourage the development of renewable energy by paying a higher price per kilowatt-hour than standard energy. The additional payments typically are used to support increased investment in renewables resources or to purchase renewable energy from independent producers. As of June 1998, about 40 electric companies offered green pricing programs (Nogee et al. 1999).

36 The term "green" power is used here to refer to only renewable resources. Some states (e.g., Texas) have included natural gas as a "green" power source.

Green marketing refers to the offering of electricity services from renewable resources by competitive suppliers in an electricity market with retail competition. Green marketing has begun in several states with retail electricity competition—California, Massachusetts, Rhode Island, and Pennsylvania. Pilot programs have been initiated in other states—New Hampshire, Massachusetts, Oregon, and Colorado (Wiser et al. 1999).

(2) Policy Impact

Green pricing has achieved some success to date, with about 40 programs currently operating (Nogee et al. 1999). These programs have an average penetration rate of about 1 percent, with about 45,000 customers participating nationally (Nogee et al. 1999). This level of customer participation is estimated to create about 45 to 50 megawatts of new renewables capacity (Nogee et al. 1999).

Green marketing has been developed in California, Massachusetts, Rhode Island, and Pennsylvania, with about 20 total products available across the four states (Wiser et al. 1999). In California, retail marketing has had limited success since the default service price, based on wholesale generation prices, offered to customers who remain with the incumbent provider is much lower than the price that can be offered by retail marketers. Consequently, only 0.9 percent, or about 78,000, residential customers had switched by the end of 1998 (Wiser et al. 1999).[37] Among residential customers who have switched suppliers, approximately 30,000 to 40,000 customers, or 40 to 50 percent, have opted for green power products. Among customers who did not opt for green power products, almost all have been switched to green products so that marketers can take advantage of the 1.5 cent subsidy per kilowatt-hour, which will be gradually phased out. The comparatively low default service price also has forced marketers to rely on non-price attributes, such as the appeal of green power, to be competitive.

In Pennsylvania, an estimated 100,000 of the 450,000 residential customers that have switched are utilizing green power products (Wiser et al. 1999). The total number of customers switching represents almost 10 percent of all residential consumers, with about 2 percent selecting green products. The higher success of retail marketers in Pennsylvania is attributed primarily to the use of "shopping credits" intended to cover supplier marketing and overhead costs in addition to the wholesale cost of electricity (Nogee et al. 1999, Wiser et al. 1999).

c. Net Metering

(1) Policy Overview

For many electricity users who have installed renewable energy sources to supplement or fully power their electricity demands, it is important to be interconnected with the

37 The number of non-residential consumers switching to non-incumbent providers has been much larger. In total, about 11.6 percent of all load has switched providers, although 97 percent of this load was comprised of non-residential consumers (Wiser et al. 1999). These consumers are most likely to select providers based on price rather than other attributes of the energy provided.

electricity grid. Interconnection allows users to draw energy when their self-generation is inadequate and supply energy when their self-generation exceeds their demands (Nogee et al. 1999, Wan and Green 1998). Net metering is a policy that allows electricity customers to maintain flexibility by only billing them for the net amount of energy consumed. This is accomplished by allowing customers to run their electricity meter backward during periods when they supply electricity, and forward when they draw energy. If they are net suppliers of energy, these customers typically receive the wholesale market price.

Many states adopted net metering as a part of implementing federal PURPA standards. Net metering legislation is in place in 25 states, although the type and size of technologies eligible and the terms of net metering differ (U.S. Department of Energy 1999a, Wan and Green 1998). Utilities in a number of other states also offer net metering, although they are not required to do so.

In addition to providing interconnection to the electricity grid for renewable resources, net metering also may provide interconnection for other distributed resources. These resources include technologies such as fuel cells and natural gas microturbines. Because of concerns about the potential revenue loss from expanded growth of renewables and distributed resources, seven states have placed caps on the quantity of generation that can be interconnected through net metering (Nogee et al. 1999, U.S. Department of Energy 1999a). These caps insure that potential revenue losses to utilities from net metering do not become too significant.

(2) Policy Impact

Despite the fact that net metering programs have been available for more than ten years in many states, evidence suggests that the effect of metering programs on non-hydro renewables has been limited (Wan and Green 1998). For example, a Minnesota law has existed since 1983, but there are only 110 net metering customers (Wan and Green 1998). Relatively little information on net metering programs is available since electric companies typically are not required to report results (Wan and Green 1998). Anecdotal evidence, however, suggests that relatively few customers participate (Wan and Green 1998).

d. Tax Credits

(1) Policy Overview

The Energy Policy Act of 1992 made federal tax credits available for several types of renewable energy. The tax credits include a 10 percent investment tax credit for solar and geothermal energy, extended from previous legislation, and a production tax credit of $15.00 per megawatt-hour for wind and "closed loop" biomass technologies.

(2) Policy Impact

The provision of production tax credits has been important to sustaining some continued growth in the wind power industry because wind power is often not much more expensive than other sources (Nogee et al. 1999). Due to the high cost of "closed loop" biomass facilities, no biomass facilities have taken advantage of the production tax credit. This situation might change if biomass credits were extended to other types of biomass generation, particularly the co-firing of biomass with coal. Overall, experience suggests that tax credits could increase investment in renewable technologies if costs were similar to those of other non-renewable generation options.

4. Constraints on Siting Power Plants

a. Policy Overview

The siting of all industrial facilities has grown increasingly complex over the past several decades. These complexities arise from several factors, including:

- *Environmental permit requirement*—Many additional permits are required in order to site facilities, including local land use variances, air and water quality permits, and other local, state, and federal permits.
- *Involvement of local interests*—Local interests have become increasingly involved in the process of siting industrial facilities. This involvement may be initiated through a variety of means, including participatory siting processes and legal actions.

These factors suggest that any proposed new electricity plant would have to overcome many regulatory hurdles. The precise hurdles depend on the location of the facility, the types of impact, and the specific groups involved in the process.

Table 10 shows estimates of new electric generation facilities based on capacity forecasts by the EIA. A total of 967 new fossil fuel generation facilities would be required

Table 10. Projected New Electricity Generation Facilities: 2005 to 2020

	Average Plant Size (MW)	Number of Facilities	
		2005–2010	2010–2020
BUSINESS-AS-USUAL			
Coal	400	7	21
Combined Cycle (Gas)	250	157	371
Combustion Turbine (Gas)	160	184	227
Totals		248	619
KYOTO			
Coal	400	0	0
Combined Cycle (Gas)	250	447	526
Combustion Turbine (Gas)	160	14	60
Totals	-	461	586

The Kyoto scenario assumes a domestic target of 1990 + 9 percent emissions with Annex 1 trading. Number of facilities calculated by dividing estimates of capacity additions from the EIA projections by assumed plant sizes.

Source: U.S. Department of Energy 1998b.

from 2005 to 2020 under BAU. Under the Kyoto Protocol this number would increase to 1,047. These estimates assume that all additional capacity is developed in new sites. Some additional capacity might result from the re-powering of existing units, such as coal-burning plants, that would not require the development of new sites.

b. Policy Impact

The growing complexity of the siting process means the siting of an electric facility has become increasingly lengthy and costly in the past several decades. All types of electricity generation facilities have experienced difficulties, including renewables, although there are differences across fuel types. These differences are very difficult to quantify.

5. *Constraints on Siting Natural Gas Delivery Facilities*

The use of North American (U.S. and Canadian) natural gas supplies for electric generation units requires transmission pipeline networks to move gas from wellhead locations to end users. The most efficient method to import gas from sources outside of North America is as a highly compressed and cooled liquid (liquefied natural gas or LNG). Receiving and using LNG require port facilities and equipment to return the gas to pipeline conditions. All of these facilities require approvals from various federal and state agencies. These processes affect the cost and feasibility of expanding natural gas use by electric utilities.

a. Policy Overview

Siting new natural gas pipelines requires several types of reviews and approvals (Resource Data International, Inc. 1999). The key reviews include the following:

- *FERC approval*—FERC must approve all pipeline expansions, including a determination of the necessity of each project.
- *Landowner opposition*—Opposition by landowners or nearby residents may impact siting through several channels, including the FERC approval process. This opposition may arise due to right-of-way issues or environmental concerns.

Problems at any stage of siting, particularly caused by landowner opposition, may significantly delay a project and lead to cost increases.

b. Policy Impact

Demand for natural gas pipelines will continue to grow in the coming decades. Table 11 reports results from a recent study by Resource Data International, Inc. (RDI) (Resource Data International 1999). Over the period 1990 to 1998, about 15,000 miles of pipeline were laid, with another 16,000 miles projected for the five-year period from 1999 to 2004. Projections over the next five-year period from 2005 to 2010 depend on assumptions regarding the Kyoto Protocol. The projected miles of natural gas pipeline range from 12,000 under BAU (i.e., no Kyoto Protocol), to 24,000 miles under the Kyoto Protocol with no international trading.

Table 11. Historical and Projected New Natural Gas Pipeline Capacity: 1990 to 2020

Period	*Miles of New Pipeline*
1990 to 1998 (actual)	15,000
1999 to 2004	16,000
2005 to 2010	
Business-as-Usual	12,000
Kyoto—Full International Trading	15,000
Kyoto—Annex I Trading	21,000
Kyoto—No Trading	24,000

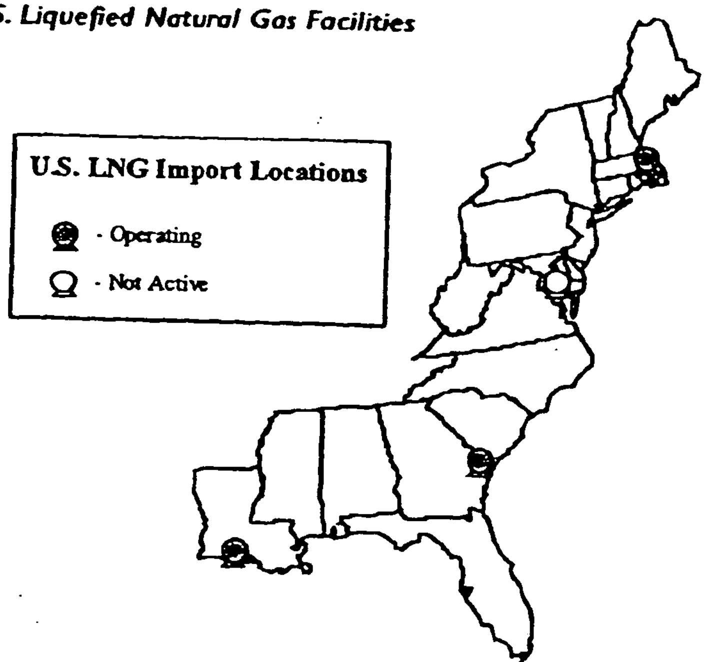
Source: Resource Data International, Inc. 1999.

Successful installation of additional natural gas pipeline could pose significant challenges to the siting process. The recent RDI study concludes:

> Landowner opposition, regulatory hurdles, and contractual issues have slowed pipeline construction in recent years. Such delays could not be tolerated in the tight timeframe for Kyoto Protocol implementation and would jeopardize U.S. compliance and gas deliverability. (Resource Data International 1999)

The U.S. currently has four LNG terminals (see Figure 23). Current imports of LNG supplies are only 0.08 trillion cubic feet (TCF) per year, or less than 0.5 percent of U.S. gas

Figure 23. U.S. Liquefied Natural Gas Facilities



Source: Electric Power Research Institute 2000.

demand. At full capacity, the existing four facilities could handle 1.2 TCF per year (Electric Power Research Institute 2000).

The limited use of LNG in the U.S. is due to the high cost in comparison to other North American sources (e.g., see Resource Data International 1999). Increases in future natural gas prices may make LNG resources more competitive.

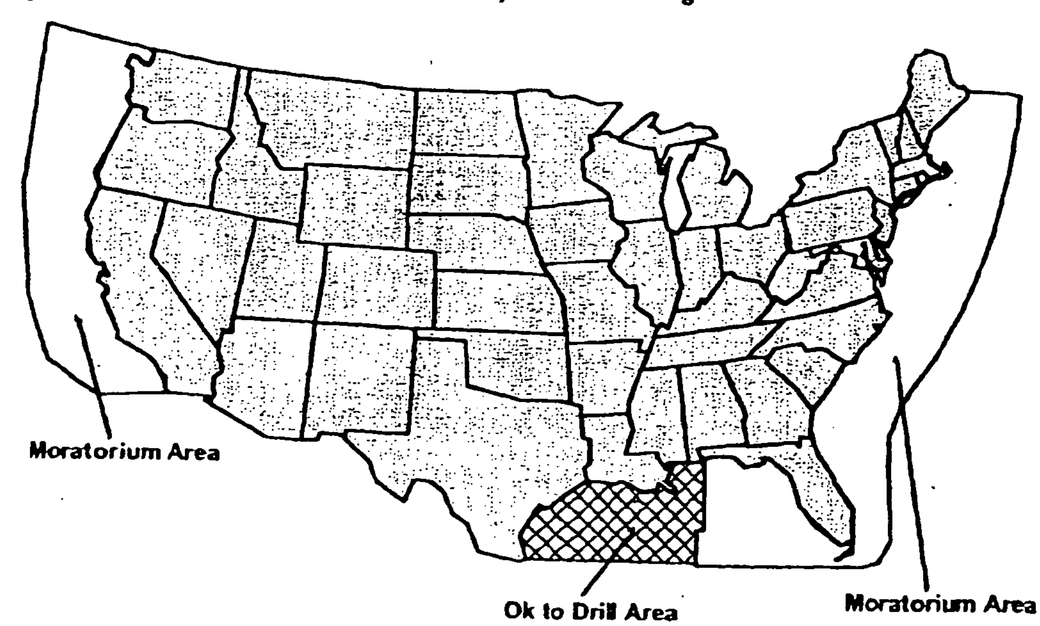
6. Constraints on Oil and Gas Drilling

Major domestic natural gas reserves are in areas that are subject to drilling restrictions. These areas are offshore ocean reserves and reserves on federally owned land. This section discusses policies that place restrictions on the development of energy resources in these locations.

a. Policy Overview

Primarily in response to past oil spills—such as those off Santa Barbara and in Alaska's Prince William Sound—there is a moratorium on new offshore drilling leases on the U.S. Outer Continental Shelf (OCS), except for the central and western regions of the Gulf of Mexico (see Figure 24). In June 1988, this drilling moratorium was extended to 2012 (Resource Data International 1999).

Figure 24. Lower-48 Moratorium Areas for U.S. Drilling



Moratorium currently in effect through 2012.

ource: Resource Data International 1999.

Prior to the establishment of the offshore drilling moratorium, the oil and gas industry established the potential for substantial quantities of gas in many offshore areas including Florida, North Carolina, and New Jersey (Electric Power Research Institute 2000). Furthermore, advances in offshore drilling technology around the world during the last decade have significantly enhanced the likelihood that these areas can provide future gas supplies (Electric Power Research Institute 2000). The Potential Gas Committee (PGC) projects 54 TCF of natural gas in areas subject to the moratorium. Other assessments have estimated the total to be more than 100 TCF (Electric Power Research Institute 2000). Although not affecting near-term supplies of natural gas, a continued moratorium on offshore drilling may affect long-run supplies in the post-2020 period.

There are also several constraints on oil and gas drilling on federal lands, particularly in the Rocky Mountain region. The Department of Interior has suggested that some federal lands will be off limits to future drilling but has not named them, raising some uncertainty for development of gas reserves in this region. Drilling in these areas would in many cases require agency decisions that are subject to public participation. In past cases, environmental groups have intervened to oppose drilling activities on public lands, as seen in the opposition to drilling leases in the Lewis and Clark National Forest (Resource Data International 1999). In other cases, drilling may affect particular local, environmental, or resource issues leading to other local conflicts. Drilling may, for example, affect the level of water aquifers since drilling frequently pumps out water in addition to oil or gas (Resource Data International 1999).[38]

b. Policy Impact

Although constraints on access to various reserves may not affect attainment of near-term natural gas demand, when demand is higher these sources may need to be utilized. The impact reported in the recent RDI study of the Kyoto Protocol (see the discussion of climate change policies) is based on the assumption that drilling would be permitted in the Eastern Gulf and in other sensitive regions (Resource Data International 1999). If this drilling were prohibited, the estimated impact reported by the RDI study may be greater. With regard to public lands, RDI states that "producers have voiced concerns about reaching a 30 TCF market without access to these public lands" (Resource Data International 1999).

The recent EPRI study examines the effect of the off-shore drilling moratorium on long-run natural gas reserves under a policy scenario or Current Policy Direction, that includes the Kyoto CO_2 targets, the NO_X SIP Call, and additional SO_2 reductions (Electric Power Research Institute 2000). Using natural gas reserve estimates from the PGC, the study projects that the supply of natural gas may be constrained within the next 50 years if the drilling moratorium is not repealed. Such a supply constraint likely would lead to increases in the price of natural gas.

38 Management of pumped water can address this impact. For example, the water could be used for agricultural irrigation, which returns the water to the aquifer (Resource Data International 1999).

Table 12 shows the years in which the PGC reserves become constrained under different scenarios.[39] Based on the PGC reserve estimates, reserves would be constrained by 2031 in the business-as-usual case and by 2025 under the Current Policy Direction with high macroeconomic growth.[40] A repeal of the offshore drilling moratorium after it expires in 2012, however, would have a significant effect on reserves. As shown in Table 12, repeal of the moratorium could increase the lifetime of natural gas supplies by 15 or more years under expected economic growth.

These projections are based on current reserve estimates. Future reserve estimates may be greater due to technological advances or discovery of new resources. Higher natural gas prices also would increase reserve estimates by making it economical to obtain gas from tight sands (i.e., gas in formations with low permeability), deep gas deposits, and methane hydrates (Electric Power Research Institute 2000, Environmental Law Institute 1999).

Table 12. Projected Years of Natural Gas Reserve Constraints under CO_2, NO_X, and SO_2 Policies

	Year		
	Moratorium Continued and Current PGC Assessment of Gas Resources	*Moratorium Continued and Assessment of Gas Resources Increased*	*Moratorium Repealed and Assessment of Gas Resources Increased*
Business-As-Usual	2031	2038	2050+
Current Policy Direction	2027	2035	2050+
Current Policy Direction with High Economic Growth	2025	2031	2045

U.S. gas resources are "constrained" when 9.5 years of reserves remain (Electric Power Research Institute 2000). At this point proven reserves cannot be replaced, resulting in a decline in deliverability and some form of rationing (Electric Power Research Institute 2000). Reserves include proven, probable, possible, and speculative resources (Potential Gas Committee 1999). Current Policy Direction includes a CO_2 policy achieving the Kyoto targets through 9 percent domestic reductions and international CO_2 permit purchase, an SO_2 policy reducing emissions 50 percent beyond Title IV Phase II targets, and a NO_X policy implementing the NO_X SIP Call.
Source: Electric Power Research Institute 2000.

39 In this context, the reserve is constrained when only 9.5 years of reserves are remaining (Electric Power Research Institute 2000). At this point proven reserves cannot be replaced, resulting in a decline in deliverability and some form of rationing (Electric Power Research Institute 2000). Reserves include proven, probable, possible, and speculative resources (Potential Gas Committee 1999).

40 As noted above, the Current Policy Direction includes the Kyoto Protocol (Annex I trading, U.S. domestic target of 1990 + 9 percent), the NO_X SIP Call, and a 50 percent reduction in utility SO_2 emissions.

Part IV ✦ Summary and Implications

This chapter summarizes the impact of potential policies and regulatory initiatives on electricity fuel use and other measures. Conclusions and implications for energy and environmental policy are given.

A. Impact of Regulatory Policies on Fuels Used for Electric Generation in the Next Two Decades

Table 13 provides a qualitative summary of the impact of the environmental and energy policies on the various fuels used for electricity generation over the next two decades. This is intended to provide a rough indication of the direction and magnitude of the potential impact and indications of conflicts and similarities.

The qualitative assessments are relatively crude. A positive sign (+) indicates that the initiative would positively affect the use of a given fuel; a negative sign (–) indicates a negative impact. The number of signs, ranging from one to three, indicates the potential importance of the policy to the particular fuel. No entry is provided when a fuel is not affected or when the impact is generally similar for all fuels.

These rough impact assessments suggest that most fuels would be subject to both positive and negative influences under these regulatory initiatives. The overall impact on each fuel type can be summarized as follows:

1. *Coal*—While coal's low cost and abundance could increase utilization of coal, current regulatory initiatives generally would decrease coal utilization. The most significant initiatives are the policies affecting air emissions and climate change.
2. *Natural gas*—Natural gas is currently the fuel of choice for new electricity generation and is favored by many regulatory initiatives. Several policies may limit the rate of natural gas expansion (pipeline siting constraints) and the long-term availability of reserves (drilling constraints).
3. *Nuclear*—Some regulatory initiatives, particularly climate change policy, could increase nuclear utilization significantly, while others, such as the requirement to relicense units or large cooling water investments and the unresolved issue of nuclear waste disposal, may provide a constraint to continued utilization.
4. *Hydroelectric*—Due to low variable costs, hydroelectric units are anticipated to run at full capacity. Hydroelectric relicensing may impose operating conditions or constraints that may reduce generation capacity and limit when these units can provide power.
5. *Non-hydro renewables*—Non-hydro renewables are anticipated to experience some continued growth and a stable share of the fuel mix. Several regulatory initiatives would increase utilization of non-hydro renewables, including climate change policies and policies directly targeting non-hydro renewables.

Table 13. Potential Qualitative Impacts of Regulatory Policies on Electricity Generation Fuels in the Next Two Decades

	Coal	*Natural Gas*	*Nuclear*	*Hydro*	*Non-Hydro Renewables*
AIR QUALITY					
NO_x	– –				
SO_2	– –				
Mercury	– –				
CLIMATE CHANGE	– – –	+ +	+	+	+ +
WATER QUALITY					
Effluent Guidelines	–				
Cooling Water	–		–		
WASTE DISPOSAL					
Solid/Hazardous	–				
Nuclear			– –		
ENERGY POLICIES					
Hydro Relicensing				–	
Nuclear Relicensing			–		
Renewables Policy					+ +
Siting Generating Plants	–	–	– –	–	–
Siting Natural Gas Pipelines		–			
Drilling Constraints		–			

A minus sign (–) indicates that the policy would negatively affect the use of the given fuel for electric power within the next two decades. A plus sign (+) indicates that the policy would positively affect the use of the given fuel for electric power within the next two decades. The number of signs provides a qualitative indication of the potential magnitude of the impact of alternative policies. Oil is not included as a fuel because it is projected to account for less than 1 percent of the fuel mix.

B. Overall Impact on Costs and Electricity Prices

These various policy initiatives also could have substantial effects on the cost and price of electricity as well as the overall economy.

1. Impact on Electricity Generation Costs and Rates

These various policy initiatives could have substantial effects on the overall cost and price of electricity. No comprehensive assessments are available for all of the initiatives, although this report summarizes results for the individual policies.

Climate change is projected to have the largest impact on electricity rates. The Kyoto Protocol with Annex I trading is projected to increase 2020 electric rates about $30 per megawatt-hour (in 1999 dollars), which is almost a 45 percent increase in current prices. The impact would be almost twice as great with no international carbon trading and about one-third as great under complete international carbon trading.

2. *Other Impacts*

The cumulative impact of these regulatory initiatives could extend to the economy as a whole. The studies reviewed in this report predict that electricity price increases and other costs could adversely affect the U.S. economy, leading to short-term increases in inflation and decreases in the rate of overall economic growth. Abrupt changes also could create substantial regional declines in employment in energy-producing areas.

In addition to the cumulative impact, the piecemeal nature of the policy initiatives could lead to conflicts. As noted in the recent EPRI report, some of the capital costs incurred may be unproductive because of the timing of the various policies. In particular, the capital equipment installed to comply with additional NO_X and SO_2 constraints required in 2003 and 2007 may be scrapped if the plants were required to comply with CO_2 requirements assumed to begin in the 2008–12 period.

The potential inconsistency of air quality and climate change requirements is an example of the more general issue of inconsistency among the various potential policies. Some predicted changes for a given initiative may not be achievable if other policy initiatives are undertaken. Constraints on the siting of gas pipelines or drilling of natural gas, for example, could limit the feasible increase in natural gas use, at least within the next two decades. Thus, the extensive shift to gas-fired generation predicted under climate change policies may not be feasible in light of other policies that are carried out at the same time. These possibilities reflect the disadvantages of a piecemeal approach to energy and environmental policy that does not take into account interactions among policy initiatives.

C. Concluding Remarks and Implications

The studies reviewed in this report indicate that future energy and environmental policies and regulations could have substantial effects on the future electric power fuel mix and on electricity costs and rates. The fact that energy and environmental policies could lead to major shifts in the electric power fuel mix and have other economic ramifications does not mean that the policies or regulations are not warranted. One can view the policies and regulations as necessary corrections to market decisions on electricity fuel use. As long as the corrected prices of the various fuels reflect social costs (including costs related to environmental and other externalities), according to this market view, the resulting fuel mix should not cause concern.

The policies and regulations outlined in this report are not as ideal as this market view implies.[41] Regulations on air pollution do not consist of a series of flexible emission charges reflecting external social costs. Rather, the potential air pollution policies include relatively inflexible regulatory requirements (e.g., NSR), as well as relatively flexible market-based approaches (e.g., SO_2 trading). Some of these programs set targets on the basis of benefits and costs (e.g., Section 316(b) water regulations); others expressly exclude benefit-cost considerations (e.g., setting of NAAQS). Some of these programs are based on approaches that tend to minimize the cost of meeting objectives (e.g., SO_2 trading program, RPS proposals); others are based on approaches that do not provide for cost minimization (e.g., NSPS). Moreover, policies typically are not coordinated; thus, negative and positive interactions are not taken into account.

The results presented in this report suggest three implications for future policy analyses:

First, the potential interaction effects from this large number of regulatory and policy initiatives suggest the usefulness of taking a broad look at electricity generation and the factors that influence its future. A piecemeal approach to regulatory policy seems ill suited to this situation.

Second, the substantial costs and impact of these policies suggest the importance of detailed policy analyses that would consider the costs and benefits of policy alternatives. It would be particularly useful to develop means of achieving policy objectives that avoid excessive costs and major dislocations of the energy and electric power systems.

Third, the potential for expensive scrapping of control equipment before the end of its useful life suggests the importance of considering the appropriate timing and not just the desirable level of regulatory requirements. It would be useful to consider whether temporal flexibility could be provided to electricity generators that would reduce the overall costs while maintaining important environmental and energy policy objectives. Greater flexibility in timing also would allow for time to develop lower emissions facilities and less expensive technologies that would further reduce the costs and overall impact of achieving desirable policy objectives.

41 See Davies and Mazurek 1999, Hahn 1999, Portney 1990, Center for Strategic and International Studies 1997, and Stavins 2000.

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Appendix—Detailed Impact of the Kyoto Protocol

This Appendix provides information on the effects of the Kyoto Protocol on the electric generation sector, energy prices, and the U.S. economy. The following are addressed:

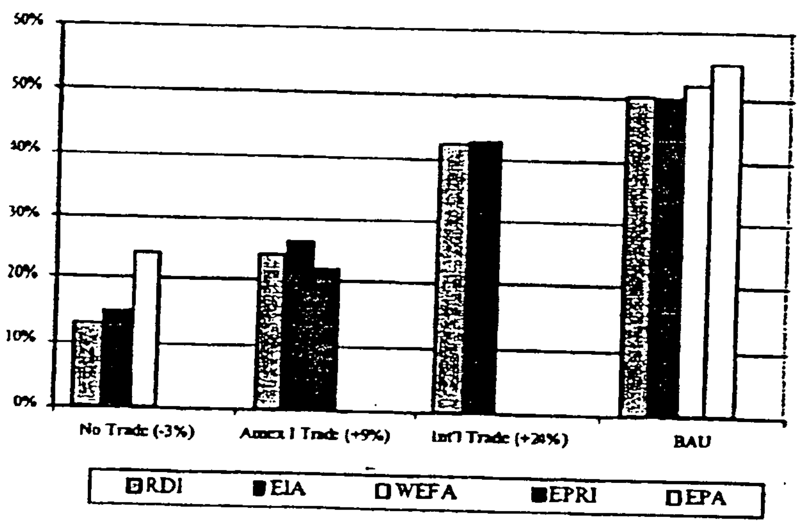
1. Impact on fuel utilization;
2. Increased energy prices and expenditures;
3. Impact on the overall U.S. economy;
4. Regional economic impacts.

A. Impact on Fuel Utilization

Several recent studies have evaluated the effects of the Kyoto Protocol on fuels used for electricity generation. These studies show that projected shifts in the electric power fuel mix due to the Kyoto Protocol are quite similar in spite of many differences in the assumptions about economic and energy parameters, model structure, and other policies in effect. This similarity of results is sometimes obscured because the studies do not necessarily use the same assumptions about international carbon trading.

Figure 25 reports the percentage of coal in the fuel mix estimated in various economic studies, grouped by international CO_2 trading case. The coal percentages are very similar

Figure 25. Estimated Percentage of Coal in the Electric Generation Fuel Mix in 2010 from Different Studies by Kyoto Carbon Trading Case



Specific carbon targets in individual studies vary slightly.

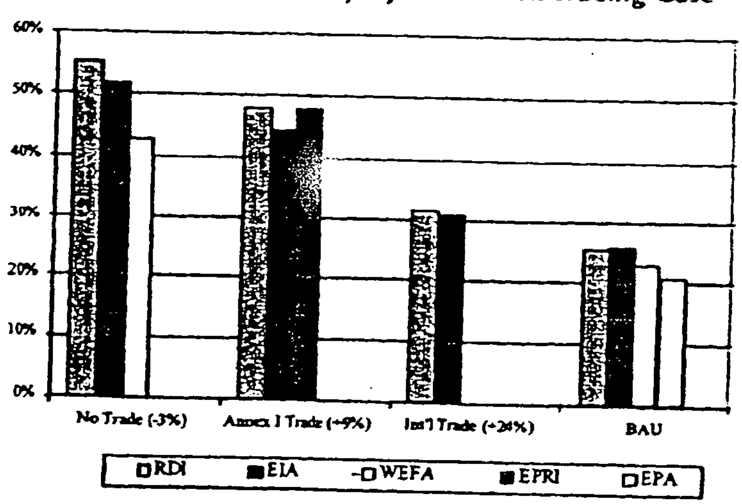
Source: Resource Data International, Inc. 1999, U.S. Department of Energy 1998, WEFA, Inc. 1998, Energy Security Analysis, Inc. 1998, Electric Power Research Institute 2000, U.S. Environmental Protection Agency 1999.

among the studies for each given trading case. Under Annex I trading all studies project that coal would be 21 to 26 percent of the fuel mix in 2010.

Figure 26 shows that projections of natural gas use also are similar for each given carbon trading case. With no international trading, natural gas utilization ranges from 43 to 57 percent of the electric energy mix in the studies. In contrast, gas utilization is much lower under BAU conditions, ranging from 20 to 26 percent of the fuel mix in the various studies.

Figure 27 shows that the Kyoto targets do not have a major impact on nuclear use. The increase in nuclear power utilization in the no international trading scenario relative to the BAU case is at most 5 percent. Figure 28 shows the increase in renewable energy under the various studies and carbon trading cases. The percentage of renewable energy does not change dramatically under the alternative carbon cases. The non-hydro renewable share, however, is affected more by the Kyoto Protocol. In the EIA study, the percent of non-hydro renewable energy grows from 2.6 under BAU to 4.8 under the Kyoto Protocol with no international carbon trading (U.S. Department of Energy 1998).

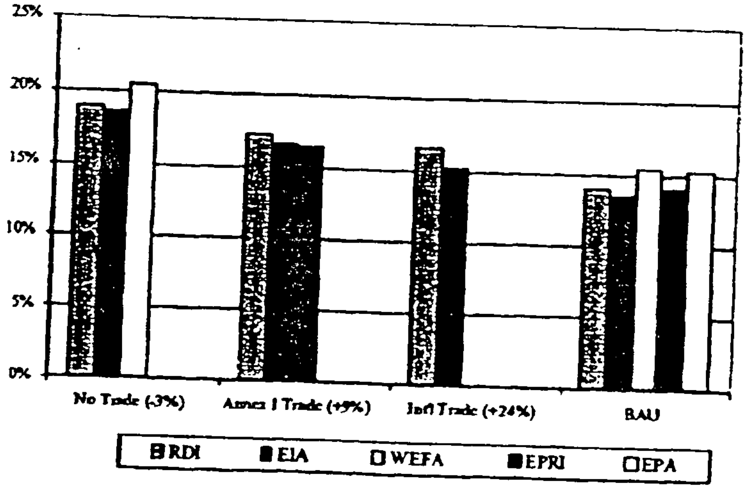
Figure 26. Estimated Percentage of Natural Gas in the Electric Generation Fuel Mix in 2010 from Different Studies by Kyoto Carbon Trading Case



Specific carbon targets in individual studies vary slightly.

Source: Resource Data International, Inc. 1999, U.S. Department of Energy 1998, WEFA, Inc. 1998, Energy Security Analysis, Inc. 1998, Electric Power Research Institute 2000, and U.S. Environmental Protection Agency 1999.

Figure 27. Estimated Percentage of Nuclear Use in the Electric Generation Fuel Mix in 2010 from Different Studies by Kyoto Carbon Trading Case



Specific carbon targets in individual studies vary slightly.

Source: Resource Data International, Inc. 1999, U.S. Department of Energy 1998, WEFA, Inc. 1998, Energy Security Analysis, Inc. 1998, Electric Power Research Institute 2000, and U.S. Environmental Protection Agency 1999.

B. Increased Energy Prices and Expenditures

Several studies estimated the impact of the Kyoto Protocol on energy prices and expenditures. These studies indicated that energy prices and expenditures could increase substantially under Kyoto if full international trading were not put in place.

1. Natural Gas Prices

Figure 29 summarizes projections of natural gas prices under the Kyoto Protocol from several recent studies, differentiated by the assumptions regarding international trading and resulting domestic U.S. requirements. The gas price increases reflect the effects of increased demand and taxes on carbon emissions. The impact on natural gas prices declines as international emissions trading becomes broader. Increases in natural gas prices range from 140 to 208 percent with no international carbon trading. The gas price increases range from 71 to 97 percent with Annex I trading. With full international carbon trading, natural gas prices are projected to increase about 50 percent. Note that in all cases natural gas prices increase significantly.

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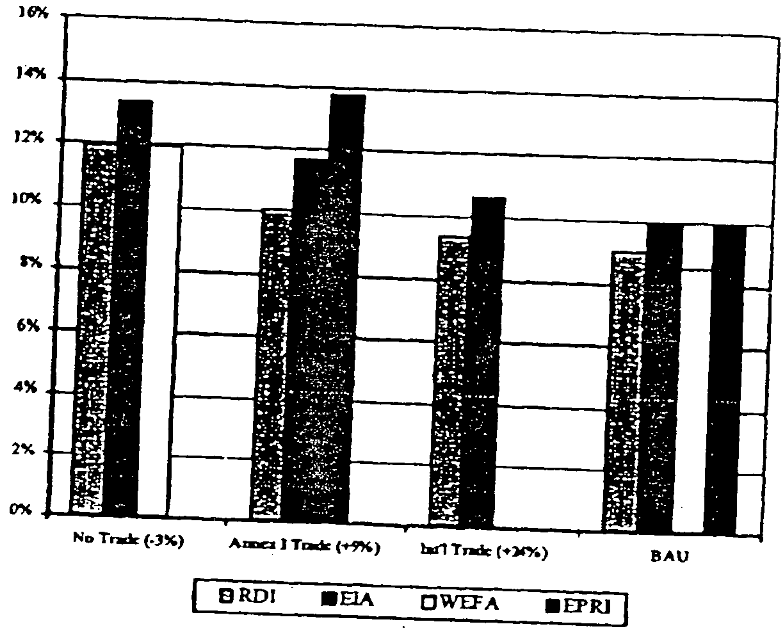
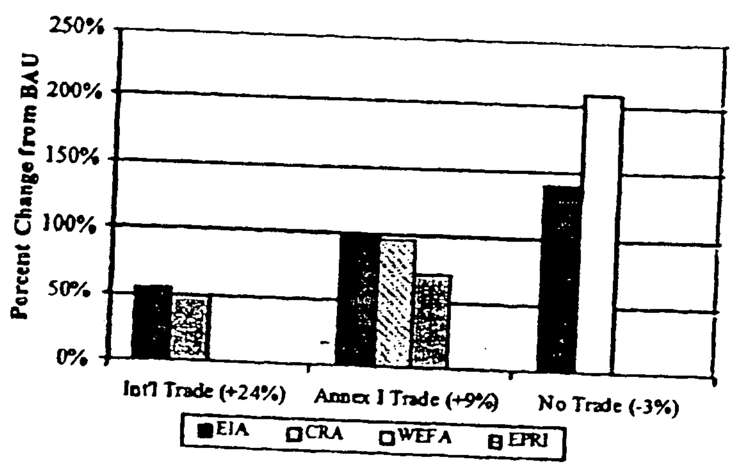
Figure 28. Estimated Percentage of All Renewables in the Electric Generation Fuel Mix in 2010 from Different Studies by Kyoto Carbon Trading Case



Specific carbon targets in individual studies vary slightly.

Source: Resource Data International, Inc. 1999, U.S. Department of Energy 1998, WEFA, Inc. 1998, and Electric Power Research Institute 2000.

Figure 29. Projected Increases in Natural Gas Prices in 2010 from the Kyoto Protocol under Alternative Trading Cases



Source: U.S. Department of Energy 1998, Charles River Associates Inc. 1999, WEFA, Inc. 1998, and Electric Power Research Institute 2000.

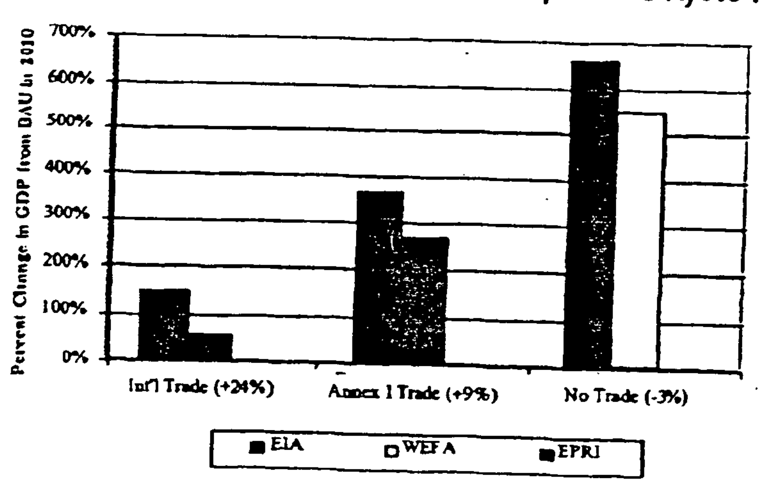
2. *Coal Prices*

Figure 30 summarizes the effects of the Kyoto Protocol on coal prices, differentiated by the assumptions regarding international carbon trading. Coal price increases reflect the effects of carbon taxes. Decreased demand for coal may have an offsetting effect, although these projections suggest that the carbon taxes have a more significant effect on prices. As expected, the impact on coal prices declines with the implementation of international emissions trading. The percent of increase in coal prices ranges from 550 to 660 percent with no trading, declines to 270 to 370 percent under Annex I carbon trading and 60 to 150 percent under full international carbon trading. Note that in all cases coal prices increase dramatically.

3. *Electricity Prices*

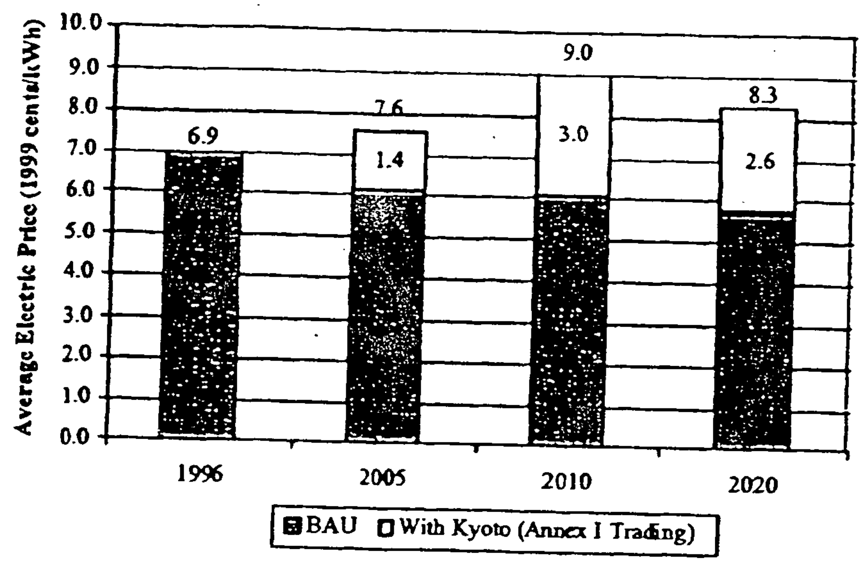
In addition to inducing large shifts in the electricity generation mix, implementation of the Kyoto Protocol could lead to substantial increases in electricity prices. Figure 31 shows EIA estimates of the electricity rate effects of the Kyoto Protocol in 2005, 2010, and 2020. These results assume Annex I trading (i.e., a domestic U.S. CO_2 target equal to 9 percent above 1990 level). In 2010, the Kyoto Protocol would raise the electricity price 3.0 cents per kilowatt-hour, from 6.0 cents to 9.0 cents, an increase of 50 percent. The rate effects of the Kyoto Protocol would be very different under other assumptions regarding international carbon trading. The EIA estimates that the impact of the Kyoto Protocol on 2020 electricity prices would be 1.7 cents per kilowatt-hour under full international carbon trading, but 3.4 cents per kilowatt-hour under no international carbon trading.

Figure 30. Projected Increases in Coal Prices in 2010 from the Kyoto Protocol



Source: U.S. Department of Energy 1998, WEFA, Inc. 1998, and Electric Power Research Institute 2000.

Figure 31. Electricity Prices under Business-As-Usual and the Kyoto Protocol



Updated to 1999 dollars.
Source: U.S. Department of Energy 1998.

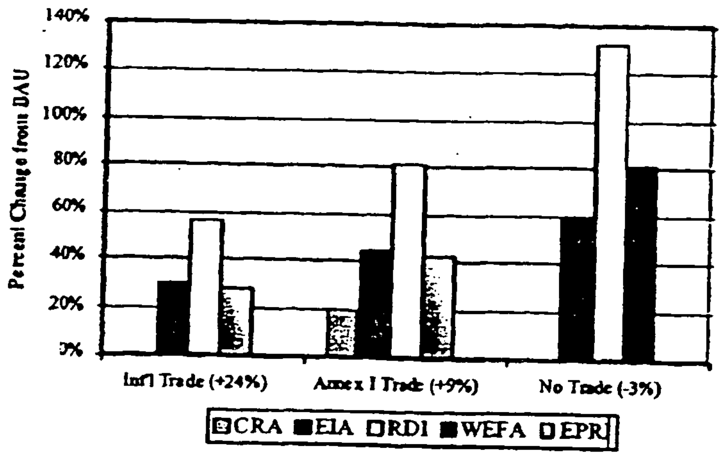
Figure 32 shows projections from various studies of the increase in electricity prices that would result from implementation of the Kyoto Protocol. As with the other energy sectors, the size of the price increase varies substantially with the level of carbon emissions trading assumed. With full international trading, price increases range from 25 percent to almost 60 percent. With no trading, price increases range as high as 130 percent.

4. Household Energy Expenditures

Higher energy prices would lead to substantial increases in household energy expenditures. Figure 33 shows the changes in household energy expenditures projected as a result of the Kyoto Protocol when combined with the NO_X SIP Call and additional SO_2 reductions consistent with potential $PM_{2.5}$ standards (Electric Power Research Institute 2000). Household energy expenditures include payments for home heating, air conditioning, and electricity but exclude transportation expenditures. By 2020, U.S. households are projected to pay 22 percent more for energy under the baseline growth assumptions.

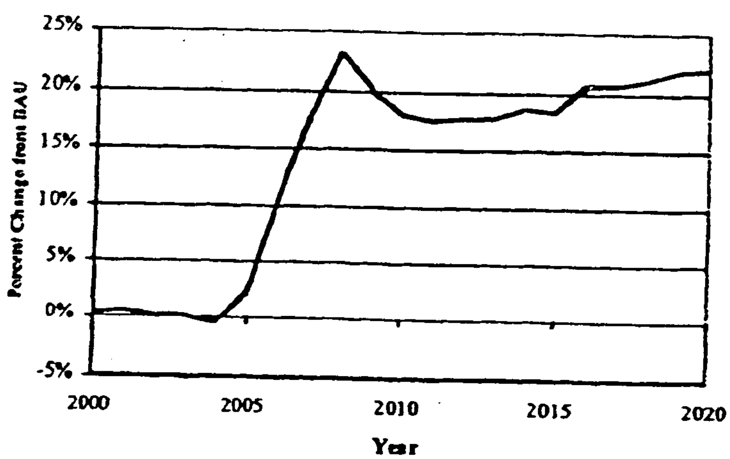
Note that these figures show the net result of two opposing phenomena. As energy prices rise, households spend more money on any given level of energy use, which raises expenditures. However, higher prices cause consumers to reduce their overall use of energy, thus lowering energy use. The projected reduction in household energy use is shown in Figure 34. Energy use is projected to decline about 15 percent relative to BAU as a result of the Kyoto, NO_X, and SO_2 initiatives. This means that household expenditures would increase

Figure 32. Projected Percent of Increase in Electricity Prices in 2010 from the Kyoto Protocol



Source: Charles River Associates Inc. 1999, U.S. Department of Energy 1998, Resource Data International, Inc. 1999, WEFA, Inc. 1998, and Electric Power Research Institute 2000.

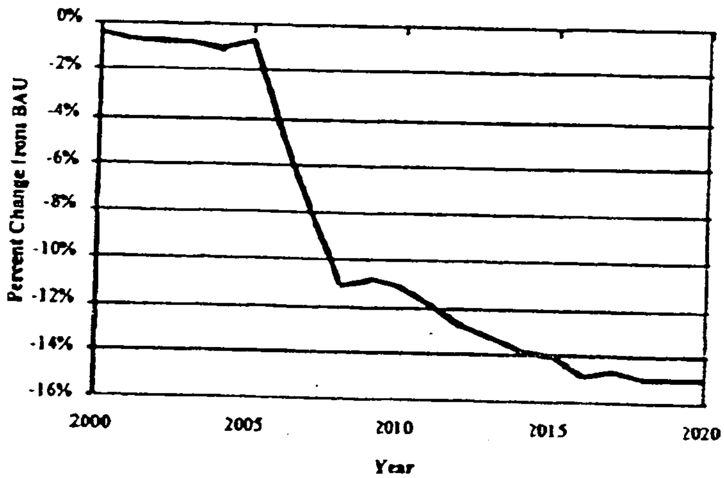
Figure 33. Impact of CO_2, SO_2, and NO_X Policies on Residential Energy Expenditures



Results illustrate the percentage increase relative to business-as-usual case. The policies include the Kyoto Protocol (U.S. domestic emissions at 1990 + 9 percent levels with Annex I trading), the NO_X SIP Call, and a 50 percent reduction in SO_2 from Title IV Phase II levels.

Source: Electric Power Research Institute 2000.

Figure 34. Impact of CO_2, SO_2, and NO_X Policies on Residential Energy Consumption



Results illustrate the percentage increase relative to business-as-usual case. The policies include the Kyoto Protocol (U.S. domestic emissions at 1990 + 9 percent levels with Annex I trading), the NO_X SIP Call, and a 50 percent reduction in SO_2 from Title IV Phase II levels.

Source: Electric Power Research Institute 2000.

under these policy initiatives while the quantity of energy services households receive diminishes.

C. Adverse Impact on the U.S. Economy

Since energy and electricity are such an essential part of the U.S. economy, large price increases—such as those experienced during the 1970s—might lead to changes in overall performance. Many studies project that the Kyoto Protocol will impact the U.S. economy (U.S. Department of Energy 1998, WEFA 1998, Energy Security Analysis 1998, Electric Power Research Institute 2000, Edmonds et al. 1997, DRI McGraw-Hill 1998).

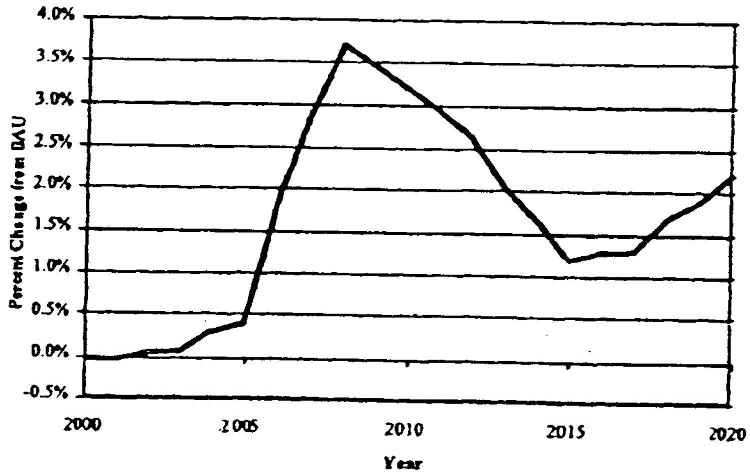
1. Inflation

Figure 35 shows the projected increase in the consumer price index (CPI) from the recent EPRI study, evaluating the effects of the Kyoto, NO_X, and SO_2 initiatives. The CPI is projected to increase almost 4 percent in the initial years of the Kyoto targets.

2. Economic Growth

Figures 36 through 38 show the projected effects of the Kyoto Protocol on gross domestic product (GDP) from several studies. Figure 36 shows the impact of no international carbon trading. Figure 37 shows the Annex I carbon trading case; Figure 38 shows the full

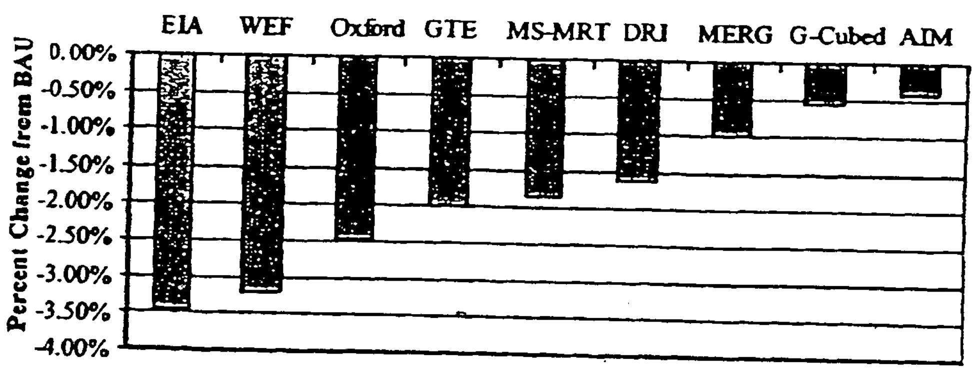
Figure 35. Projected Impact of CO_2, NO_x, and SO_2 Policies on Consumer Price Index



Results illustrate the percentage increase relative to business-as-usual case. The policies include the Kyoto Protocol, the NO_X SIP Call, and a 50 percent reduction in SO_2 from Title IV Phase II levels.
Source: Electric Power Research Institute 2000.

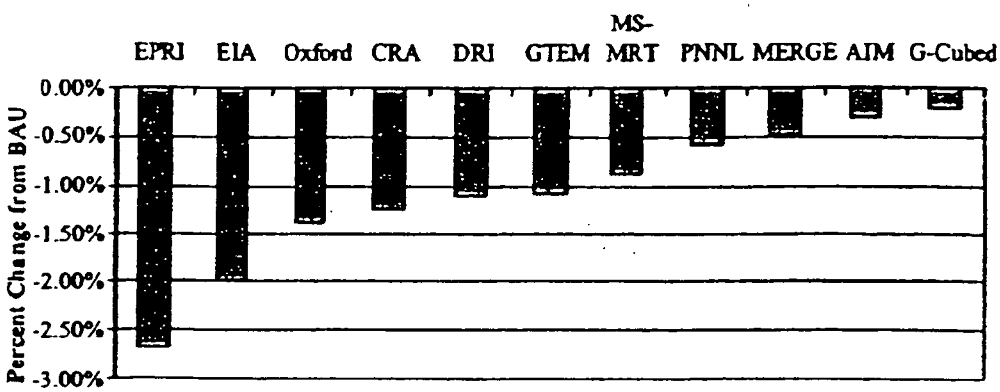
international trading case. As the figures show, the projected impact varies with the level of carbon trading. With no international carbon trading, the decline in GDP in 2010 ranges from 0.45 to 3.47 percent relative to BAU. With full international carbon trading, these impacts fall substantially, ranging from 0.05 to 1.1 percent.

Figure 36. Impact of Kyoto Protocol with No Carbon Trading on 2010 Gross Domestic Product



Source: U.S. Department of Energy 1998, WEFA 1998, Cooper et al. 1999, Tulpule et al. 1999, Bernstein et al. 1999, DRI McGraw-Hill 1998, Manne and Richels 1999, McKibbin et al. 1999, and Kainuma et al. 1999.

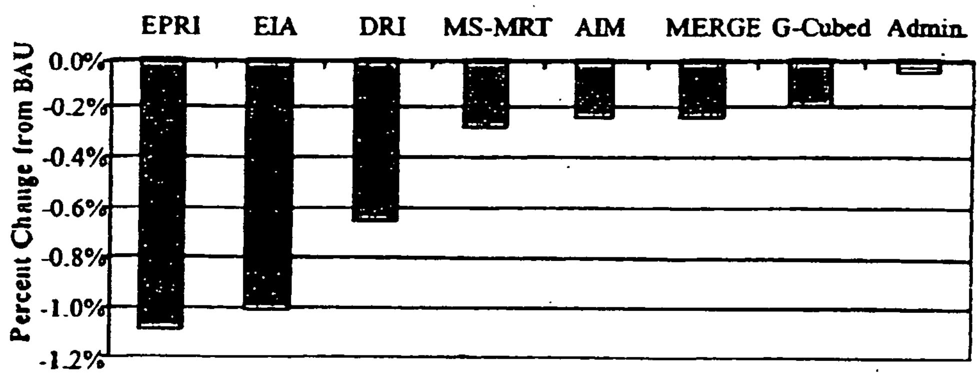
Figure 37. Impact of Kyoto Protocol with Annex I Carbon Trading on 2010 Gross Domestic Product



The EPRI study includes the effects of the NO_X SIP Call and a 50 percent reduction in SO_2 from Title IV Phase II levels as well as the Kyoto Protocol.

Source: Electric Power Research Institute 2000, U.S. Department of Energy 1998, Cooper et al. 1999, Charles River Associates 1999, DRI McGraw-Hill 1998, Tulpule et al. 1999, Bernstein et al. 1999, Edmonds et al. 1997, Manne and Richels 1999, Kainuma et al. 1999, and McKibbin et al. 1999.

Figure 38. Impact of Kyoto Protocol with International Carbon Trading on 2010 Gross Domestic Product



The EPRI study includes the effects of the NO_X SIP Call and a 50 percent reduction in SO_2 from Title IV Phase II levels as well as the Kyoto Protocol.

Source: Electric Power Research Institute 2000, U.S. Department of Energy 1998, DRI McGraw-Hill 1998, Bernstein et al. 1999, Kainuma et al. 1999, Manne and Richels 1999, McKibbin et al. 1999, and U.S. Presidential Administration 1998.

D. Regional Economic Impact

Implementation of the Kyoto Protocol could have a particularly severe economic impact in certain regions. The reduced demand for coal expected to result from implementation of the Kyoto Protocol and other air quality initiatives affecting NO_X and SO_2 would affect coal production, which is concentrated in relatively few states (Electric Power Research Institute 2000). The decline in demand for coal would cause loss of coal mining jobs (U.S. Department of Energy 1998). Table 14 reports projections of the number of coal mining jobs under different scenarios evaluated in the EIA study of the Kyoto Protocol (U.S. Department of Energy 1998). National coal mining employment is projected to fall from 68,519 jobs under the BAU to 42,531 under Annex I trading and to 29,187 under no trading.

Declines in employment are projected for all sectors of the economy under the Kyoto Protocol (U.S. Department of Energy 1998, WEFA 1998, Electric Power Research Institute 2000). Regional employment losses differ due to differences in coal mining employment, coal mining activity, the number of energy- and fossil fuel-dependent industries, and activity in other energy sectors (WEFA 1999, U.S. Department of Energy 1998). The WEFA study projects that employment losses in 2010 at the state level would range from 8.7 percent in Montana to less than 0.5 percent in the District of Columbia (WEFA 1999). Thirteen states are projected to experience declines in employment of more than 4 percent.

Table 14. Projected Coal Mining Jobs under Alternative Kyoto Protocol Scenarios

		Kyoto Scenario		
		Int'l. Trade	*Annex I Trade*	*No Trade*
Region	*BAU*	*1990 + 24%*	*1990 + 9%*	*1990 – 3%*
Appalachia[1]	49,477	41,617	32,386	24,307
Interior[2]	8,043	7,801	6,257	3,484
Powder River Basin[3]	5,013	3,827	1,829	844
Other West[4]	5,693	4,785	2,254	941
U.S. Total	68,519	58,223	42,531	29,187

[1] PA, OH, MD, WV, VA, and KY (east).

[2] IL, IN, KY (west), IA, MO, KS, AR, OK, TX, LA.

[3] WY, MT, and ND.

[4] CO, UT, NM, AZ, AK, and WA.

Source: U.S. Department of Energy 1998.

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MISCELLANEOUS GENERATING/TRANSMISSION STATISTICS

WSCC

The Western Systems Coordinating Council (WSCC) covers all or parts of Washington, Oregon, California, Arizona, New Mexico, Colorado, Utah, Nevada, Idaho, Wyoming and Montana, as well as part of Mexico and Canada.

The region is divided into four subregions: the Northwest Power Pool Area is winter peaking and heavily dependent on hydro power (65 percent of installed capacity); the Rocky Mountain Power Area, which can be either summer or winter peaking with a 24 percent hydropower and 59 percent coal-fired generating capacity mix; the Arizona-New Mexico-Southern Nevada Power Area, which is summer peaking with a 17 percent nuclear and 44 percent coal-fired generating capacity mix; and the California-Mexico Power Area, which is summer peaking and heavily dependent on gas-fired generating units (47 percent of installed capacity).

The Northwest Power Area, which covers all of Washington, Oregon, Idaho and Utah and parts of Nevada, Montana, Wyoming and California, has about 55,000 megawatts of winter generating capacity, about 65 percent of which is hydropower. Only about 700 megawatts of net new generating capacity has been added since 1990, most of which has been natural gas. Operating capacity has increased by only 2 percent over a 10-year period.

As a result, since 1990, the Northwest Power Area's dependence on generating resources outside the region has increased, as the summer surplus of capacity over peak load has decreased and the winter capacity deficit has grown.

From 1995 to 1999, generation in the West outside of the Pacific region (California, Oregon and Washington) grew by 22 percent, which was twice the rate in the Pacific region.

The generating capacity margin adequacy over the next ten years is heavily dependent upon the timely construction of roughly 30,200 megawatts of net new generation.

Within the WSCC, California is experiencing transmission constraints in moving power into southern California and from southern and central California to northern California. There are transmission constraints in the San Diego area. During extreme cold weather periods, the import capability on the California to Oregon intertie may be severely limited in moving power from south to north. The Puget Sound area is facing transmission constraints, which limits the transfer of power between the province of British Columbia and the state of Washington. The transmission paths between southeastern Wyoming and Colorado often become heavily loaded.

MAIN

The Mid-America Interconnected Network (MAIN) covers portions of Iowa and Minnesota, most of Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin and most of the Upper Peninsula of Michigan.

More than 3,000 megawatts of new generating capacity is scheduled to be added within the MAIN region in 2000. The majority of planned capacity additions are short lead-time combustion turbine peaking units owned by merchant power producers.

The MAIN region experiences transmission constraints that limit that region's ability to import power from ECAR to the east. The Wisconsin-Upper Michigan system has inadequate capacity to import power. And, MAIN also faces transmission constraints to power imports from the west.

ECAR

The East Central Area Reliability Coordination Agreement (ECAR) covers all or parts of Michigan, Indiana, Kentucky, Ohio, Virginia, West Virginia, Pennsylvania, Maryland and Tennessee.

By 2004, the ECAR region will need an additional 15,000 megawatts of generating capacity. This means that about 22 percent of the announced new merchant capacity in the region will need to be built by 2004.

By 2009, about 66 percent of the generating capacity in ECAR will be 30 or more years old and about 29 percent will be 40 or more years old.

Coal is expected to supply about 69 percent of the total capacity requirements in 2009. ECAR currently has about 82,000 megawatts of active coal capacity, of which at least 52,300 needs to be retrofitted with selective catalytic reduction (SCR) equipment.

ECAR suffers from several transmission constraints. The power flows circulating around Lake Erie often limit the ability of the Michigan systems to receive firm power purchases from Ontario. The American Electric Power (AEP) 765 kV transmission line between West Virginia and Virginia continues to encounter certification difficulties that have delayed this vitally needed line, resulting in a reliability risk.

SERC

The Southeastern Electric Reliability Council (SERC) covers all or parts of North Carolina, South Carolina, Georgia, Mississippi, Alabama, Virginia, Louisiana, Arkansas, Missouri and the panhandle of Florida.

SERC expects approximately 34,000 megawatts of new generating capacity to be added in the region over the next ten years. These additions include natural gas-fired combustion turbine units (40 percent) and combined cycle units (44 percent).

SERC's ability to transfer power on its transmission system above contractually committed uses has become marginal at some points in the system.

FRCC

The Florida Reliability Coordinating Council (FRCC) covers the Florida peninsula.

FRCC is projecting the net addition of 11,418 megawatts of new generating capacity over the next 10 years. Of that, 10,971 megawatts are projected to be natural gas-fired combined cycle

The FRCC has limited transmission capacity to import power from the north.

MAAC

The Mid-Atlantic Area Council (MAAC) covers all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small part of Virginia.

MAAC has received requests to interconnect more than 38,000 megawatts of new generating capacity to the transmission system by 2005.

MAAC currently experiences difficulty transmitting power to the eastern part of the region. There also are transmission constraints in southern New Jersey and east central New Jersey.

NPCC

The Northeast Power Coordinating Council (NPCC) covers the state of New York, the six New England states, and the provinces of Ontario, Quebec, New Brunswick and Nova Scotia.

Currently under study in New York and New England are over 5,400 megawatts and 20,000 megawatts, respectively, of new merchant plant capacity to be in service by the end of 2002..

Ontario Hydro and Detroit Edison are in the process of enhancing the transmission facilities at the Michigan-Ontario connection.

Sources

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Preliminary Assessment of Summer 2001 Electricity Supply Conditions February 5, 2001

NERC publishes (May and November) seasonal assessments of the reliability of bulk electricity supply in North America. The Summer 2001 assessment will be published May 15. It will be based on updated supply and demand projections.

The information in this preliminary assessment relies on preliminary information and judgment, and is subject to change when the updated projections come in. As a result, nothing in this report should be publicly attributed to NERC. Also, as a general caveat on any assessment like this, even those areas that are expected to have adequate generation and transmission for the coming summer could experience problems if extraordinary weather or equipment outages occur.

The primary areas of concern for Summer 2001, as we see them now, are:

California and the Pacific Northwest

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 since 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. Therefore, most of the reliability problems are expected to occur in northern California.

The Pacific Northwest is also heavily dependent upon 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 River. 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 not be able to supply California with energy as they typically do.

Southeastern United States

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

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

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.

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Yakama Nation
Federal Energy Policy Priorities
April 2001

Interconnection and access: Amend law to require co-ops, municipal utilities and PMAs to allow tribal and on-reservation energy generation to interconnect and provide open access

Capacity building: Provide grants through Departments of Energy, Commerce, Interior to tribes to build in-house energy development capacities

Conservation: Fund conservation for tribal government and member facilities and homes

Leadership: Establish tribal energy office at DOE

Acquisition: Require DOE to follow Buy-Indian ~~Act~~ with regard to tribally-generated energy

Irrigation: Optimize tribal water projects for energy generation and consumption

PMAs: Clarify and standardize power allocation policy; allow reselling/leverage of tribal allocations

Tax: Endorse NCAI/CERT proposals, including particularly credits and accelerated depreciation

Siting: Support EPA efforts to help tribes develop environmental codes; clarify tribal authority to condemn land on-reservation for transmission rights-of-way

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Western Interconnection Coordination Forum

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WICF Summary of Needs and Projects by Area

Printed February 13, 2001.

Arizona - New Mexico - So. Nevada Area

Project Type: Concept

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
PEGT	Willard-Hollywood line (#791)	Allows reconstruction of Alamogordo-Hollywood line.	Provide loop service to Hollywood NM region.		Current	2007
PNM	Sonora-Arizona Interconnection Project (#1020)	Project would creat interchange capability where none now exists	Creation of a high voltage interconnection between Palo Verde in the WSCC and Santa Ana, Sonora in the Mexican National Grid	$360,000,000	Current	2004
TEP	Midvale - San Joaquin 138 kV (#840)		Extend existing 138 kV line (6 miles)		Delayed	2010
TEP	So.Loop-Cyprus-Sierrita 138kV line (#465)	Reinforce local transmission system.	Construct new 138kV line through Green Valley substation (24 miles).		Current	2006
TEP	Springerville - Greenlee 345kV Line (#459)	Deliver power from San Juan and Springerville generating stations.	Construct new 345kV line (110 mi.)		Delayed	2012
TEP	Tortolita to South 345 kV (#147)	In-service date under review.			Delayed	2010
Copy Interest: Arizona Public Service Company						
TSGT	Alamgordo-Dona Ana 115 kV Line (#1442)	This project will correct the extensive crossarm failure on the existing line.	Install new bracing structures on each crossarm of each structure on the 75 miles of exiting transmission line.		Current	2003
TSGT	Alamrgordo-Holywod 115 kV Line (#1440)		Rebuild 38.6 miles of existing 115 kV line with 477 MCM Conductor.		Current	2004
TSGT	Deming 115kV, 25 MVAr Cap Add (#1449)		Install a 25 MVAr bank of 115 kV caps at the Deming 115-69kV substation.		Current	2003
WALC	Shiprock-Four Corners 345kV Interconn. (#333)	Fulfill contractual commitments	Upgrade Shiprock-Four Corners 230/345 kV line (8 miles)		Current	
WAUC	NTUA - Shiprock 115 kV (#313)	- Serve area load	Interconnect Navajo Tribal Authority (NTUA) at Shiprock Sub		Current	

Project Type: Need

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
NTUA	NTUA Various 115kV and 69kV (#462)	Need for various unspecified internal projects.			Current	

Project Type: Project

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
AEPC	Topock Project (#514)	Tap on Parker-Davis 230kV line #1.	Tap on Parker-Davis 230kV line #1.		InService	1999
Copy Interest: Arizona Public Service Company						
APS	Alexander Interconnection (#1146)	Part of a capacity swap between APS and SRP. APS will get capacity to Alexander and SRP will get capacity to Knox	Add 230/69kV transformer to a SRP substation		Current	2001

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APS	Capacitors (#1317)	Replace series capacitors on the So. Navajo 500kv system and add shunt capacitors on the 230kv system	Shunt and series capacitor replacements and additions		Current	2008
APS	Desert Basin Cutin (#1311)	A new 510 MW generator will be served by cutting in an existing 230kv line	A new substation cut into an existing line		Current	2001
APS	Estrella 500/230kv substation (#860)	To serve forecasted load growth in Phoenix area.	Construct new 500/230 kV substation and 230kv lines - increase capacity by 1200 MW	$25,500,000	Current	2003
APS	Estrella cutin (#864)	To serve forcasted load growth in Phoenix.	Cutin an existing 230kv line into the new Estrella substation		Current	2003
Copy Interest: SRP						
APS	Four Corners Sub. (#279)	Terminate uprated Four Corners-Shiprock line to 345kV.	Convert FC-Shiprock 230kv line to 345kv		Current	2001
APS	Gavilan Peak Substation (#1293)		Cut a new 230/69/12kv substation into an existing 230kv line		Current	2003
APS	Gila Bend - Ajo 230 kV line (#810)	To serve forecasted growth	Construct new 230 kV line from an existing substation to a new Ajo substation. Ajo Improvement Co. is owner.		Current	2003
APS	Gila Bend - Yuma 230 kV line (#318)	To serve forecasted growth	Construct new 230 kV line - increase capacity by 200 - 400 MW		Current	2004
APS	Hilltop-N. Lake Havasu 230kv line (#861)		Construct new 230 kV line from existing substation to new N. Havasu substation. Citizen's Utility Co. is primary utility.		Delayed	2030
APS	Knox Interconnection (#1116)	Part of a capacity swap between APS and SRP. APS will get capacity to Alexander and SRP will get capacity to Knox.	SRP to cut a new 230/69kV substation into APS' Kyrene-Santa Rosa 230kV line.		Current	2000
APS	Lincoln St-Country Club uprate (#1319)		Add cooling system to underground 230kv cable		Current	2002
APS	Line reconductoring (#1310)	Various lines are planned to have the conductor changed to get higher ratings	Reconductoring of various lines		Current	2008
APS	Pinnacle Peak-TS1 230kv line (#1304)		A new 230kv line from Pinnacle Peak to TS1		Current	2004
APS	Pioneer Substation (#1294)		A new 230/69/12kv substation		Current	2007
APS	Pioneer-Gavilan Peak line (#808)	To serve forecasted growth	Constuct new 230 kV line		Current	2008
APS	Pioneer-Pinnacle Peak 230kv (#1306)		A new 230kv transmission line		Current	2008
APS	Pioneer-TS5 230kv (#1134)		A new 230kv line connecting two existing substations		Current	2007
APS	Preacher Canyon Cutin (#1175)		Change the Preacher Canyon tap to an in and out		Current	2001
APS	PV-Estrella 500kv line (#1303)	A project to increase import capability to the Phoenix area	A new 500kv line from Palo Verde to Estrella		Current	2003
APS	Reactor replacement (#1314)	replacement of deterlating reactors	Replace single phase 500kv reactors at Moenkopi and Four Corners over various years		Current	2008
APS	Saguaro 230kv switchyard (#1312)	New substation terminating 2 lines and 2 transformers	Cut two existing lines into a new substation		Current	2001
APS	Santa Rosa - Gila Bend 230kV line (#325)	To serve forecasted load growth	Construct new 230 kV line - increase capacity by 200 - 400 MW		Current	2006
APS	Transformer Additions (#1301)	various transformer additions	EHV and HV transformer additions or upgrade/replacements		Current	2009
APS	Trilby Wash Substation (#1297)	To be cut into existing 500kv lines. Lower voltage lines will be new	A new 500/230/69/12kv substation		Current	2006
APS	Trilby Wash-El Sol 230 kV line (#802)	To serve forecasted growth	Construct new 230 kV line from existing substation to new 500/230kv substation		Current	2006
APS	TS1 Substation (#1178)		A new 230/69kv substation, cut into an existing line		Current	2001
APS	TS2 substation (#1298)		A new 230/69/12kv substation		Current	2009
APS	TS2-TS3 230kv line (#1309)	A new 230kv line connecting two future substations	A new 230kv line		Current	2009
APS	TS3 substation (#1300)	A new substation and new 230kv lines	A new 230/69/12kv substation		Current	2007

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APS	TS3-Buckeye 230kv line (#1308)	A new line from an existing substation to a new 230/69/12kv substation	A new 230kv line		Current	2007
APS	TS5 Substation (#1179)	To be connected to WAPA's 230kv line from Westwing to Waddell	A new 230/69/12kv substation connected to an existing line		Current	2002
APS	W.Phoenix-White Tanks lines (#319)	To serve forcasted load growth in Phoenix.	Construct a new double circuit 230 kV line between existing substations		Current	2001
Copy Interest: SRP						
APS	Westwing- El Sol 230 kV line (#320)		Construct new 230 kV line parallel to existing lines		Current	2008
APS	Westwing-Pioneer 230 kV line (#603)	To serve forecasted growth	Constuct new 230 kV line from existing substation to new 230kv substation		Current	2009
			Study Interest: SRP			
APS	Westwing-Trilby Wash 230kv line (#1146)	To serve forecasted load growth	Construct a new 230kv line from existing substation to a new 230kv substation		Current	2009
APS	White Tanks-TS3 230kv line (#1307)	A new line from the White Tanks substation to a new 230/69/12kv substation (TS3)	A new 230kv line		Current	2007
CALP	South Point (#1388)		546,000 kW natural gas fired combined cycle power plant		Current	2001
EPE	El Paso 115 kV East Side Loop (#403)	To serve forecasted load growth. Constuction in phases from 1999-2004.	Construct new 115 kV lines on El Paso's east side	$11,140,000	Current	1999
EPE	EPE 90 MVAR Shunt Cap (#741)		Install three 30 MVAR capacitor banks on the 115 kV system. Sites to be determined.	$325,500	Current	2000
FARM	EPFS-H-H (#495)		115kv line to serve EPFS & continue to Glade Sub		Current	1998
FARM	Hart Canyon to Aztec Sub. (#27)	Part of new line from Aztec Sub. to Glade Sub.			Current	1998
FARM	Hart Canyon to Glade (#145)	Part of new line from Aztec Sub. to Glade Sub.			Current	2001
IID	Ave. 42 Transformer (#277)				Current	1998
NEVP	Avera 230 kV Substation (#961)		Construct new 230 kV substation; add 230/138 kV autotransformer. Transmission source provided by loop-in of existing Northwest-Arden 230 kV transmission line.		Current	2002
NEVP	Beltway 230 kV Substation (#774)		Construct 230/138 kV substation and 1-230/138 kV autotransformer. Transmission source from loop-in of existing Northwest-Arden 230 kV transmission line.		Current	2004
NEVP	Crystal Project (#289)		Construct new 500/230 kV substation as part of Crystal Transmission Project.		InService	1999
Copy Interest: Arizona Public Service Company						
NEVP	McCullough-Arden #2 230 kV Reroute (#367)		Reroute 230 kV circuits from 3-230 kV towers to new location		InService	1999
NEVP	McCullough-Arden #3 230kV Line (#372)		Construct new 230 kV line to increase transfer capability.		Current	2005
Copy Interest: PWEnergy						
NEVP	Navajo-McCullough/Crystal 500 kV Loop (#373)	Increase transfer capability and reliability	Loop in the existing Navajo-McCullough 500 kV line into Crystal Sub.		InService	1999
			Study Interest: Arizona Public Service Company			
NEVP	River Moutain Project (#778)		4-230 kV transmission tie lines from Mead substation into the Nevada control area		Current	2001
NEVP	Washburn-Michael Way (#388)		Construct new 138 kV line (13 miles)		InService	1999
NTUA	Navajo Transmission Project (#187)				Current	2001
Copy Interest: Pinnacle West Energy						
			Study Interest: Arizona Public Service Company			
NTUA	Navajo Transmission Project (#146)				Current	2001
Copy Interest: Resource Data International						
			Study Interest: Arizona Public Service Company			
PEGT	Colorado-New Mexico Intertie Project (#143)	Additional load growth will lead to low voltages.	113 mile 230 kV transmission line, new substation and transformer at Gladstone		Current	2001

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Copy Interest: Altec Industries, utilicorp united						
PEGT	Hollywood Capacitor (#1332)	Maintain adequate voltage for summer peak	Add a 6.25MVAR 115kV shunt capacitor		Current	2000
PGEN	Harquahala Generating Project (#1276)	Includes new 21 mile 500 kV line to Palo Verde.	4 Unit Combined Cycle Generating Project with 500 kV Transmission Line		Current	2002
Copy Interest: Altec Industries						
PNM	New 345 kV Source (#1228)	Conceptual project to serve forecasted load growth	Construct new 345 kV line into central New Mexico		Current	2006
PNM	Norton-Santa Fe 115 kV line (#382)	To serve forecasted load growth	Construct new 115 kV line (13miles)		Canceled	2000
PNM	West Mesa 345/115 kV Transformer (#437)	To serve area load growth.	New 345 /115 kV transformer at West Mesa Sub.		InService	1999
SDGE	El Dorado Energy Plant (#740)	Also includes two tranmission projects: 230kV line from generating plant to existing Eldorado substation, about .6 mile. Loop in the McCullough - Arden 230kV line into the plant, each segment being about 1 mile long.	Generation station with 2-165MW combustion turbines and 1-157MW steam turbine.		InService	2000
SDGE	Merchant Project (#666)	Also includes two tranmission projects: 230kV line from generating plant to existing Eldorado substation, about .6 mile. Loop in the McCullough - Arden 230kV line into the plant, each segment being about 1 mile long.	Generation station with 2-165MW combustion turbines and 1-157MW steam turbine.		InService	1999
SRP	Browning 500/230kV Station (#923)		New 500/230kV, 1200MVA station	$40,000,000	Current	2001
SRP	Kyrene Expansion Project (#1367)		250MW combined cycle installation on the existing station site		Current	2003
SRP	Santan Expansion Project (#1368)		750MW combined cycle installation on an existing station site		Current	2006
TEP	East Loop - Northeast 138 kV line (#328)	To reinforce local transmission system	Construct new 138 kV line through Synder Substation (13 miles)		InService	2000
TEP	Fort Lowell - Mountain Sub (#1328)		Loop existing DMP - Northeast 138 kV line south of Fort Lowell Rd near Mountain Ave. through substation.		Canceled	2002
TEP	Irvington - East Loop 138 kV line (#327)	To reinforce local transmission system	Construct new 138 kV line through 22nd Street substaion (9 miles)		InService	2000
TEP	Irvington - Vail 138 kV line (#329)	To provide additional electric service to the south central part of the TEP service area	Construct new 138 kV line through Littletown substation (4 miles)		Current	2005
TEP	Los Reales Substation (#944)		Construct substation under existing East Loop - Vail 138 kV line.		Current	2001
TEP	Rancho Vistoso - Catalina 138 kV line (#331)	To reinforce local transmission system	Construct new 138 kV line (4 miles)		Current	2009
TEP	Robert Bills Substation (#943)		Construct substation under existing East Loop - Vail 138 kV line.		Current	2009
TEP	Saguaro to Tortolita #2 500 kV (#186)				Current	2003
Copy Interest: Arizona Public Service Company						
TEP	South Sub.-DeMoss Petrie 138kV line (#464)		Construct new 138kV line (18 miles).		Delayed	2011
TEP	Sweetwater Substation (#942)		Construct new substation under existing North Loop - DeMoss Petrie 138 kV line		Delayed	2010
TEP	Vail - East Loop #3 138 kV (#657)	Increase TEP area transmission reinforcement..	To provide additional electric service to eastern part of TEP service area		Current	2006
TEP	Westwing - South #2 345kV line (#1327)				Current	2006
TNP	Alamogordo 115 KV Capacitor (#1313)	This project is aimed to correct voltage problems on the Alamogordo 115 KV bus and the Alamogordo - Hollywood 115 KV transmission line.	Addition of a 115 KV capacitor bank to the Alamogordo Substation 115 KV bus	$300,000	Current	2000
TSGT	CO-New Mexico 230 kV Intertie (#1439)		Construct a 113 mile, 1272 MCM transmission line from Walsenburg Substation in CO to a new Substation at Gladstone in NM.		Current	2003
TSGT	Elephnt Butte-Deming 115 kV Line (#1444)		Rebuild 76.3 miles of 133.1 hollowcore conductor line between Elephant Butte NM and Deming NM. New conductor will be 477 MCM.		Current	2002
TSGT	Gallup 115 kV 6.25 Mvar Caps (#1443)		Install a 115 kV, 6.25 MVAR capacitor bank with		Current	2003

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			high-side Circuit Switcher and control Panel at the Gallup Substation.			
TSGT	Socorro115 kV Brkr & Mod Ph.II (#1445)		Install 2-115 kV circuit breakers on the 149 mile West Mesa-Elephant Butte Line to Mitigate Outages.		Current	2000
WALC	Griffith Energy (#974)	Plant will be tied into transmission with two 230kV lines; Griffith-McConnico and Griffith-Peacock.	650MW of Gas fueled Generation		Current	2001
Copy Interest: Altec Industries, PPL energyPlus						
WALC	Mead series reactors (#1009)		To mitigate excessive fault current at the Mead 230kV bus, series reactors will be placed in the 230kV bus.	$4,400,000	Current	2001
WALC	Needles Substation 230/69 KV (#335)		Loop in Davis-Parker #1 230 kV line		Current	1998
WALC	South Point (#976)	Generation will be tied into transmision by 2-230kV lines (8 miles).	New gas fired generation (500MW)		Current	2001
WAUC	Shiprock to Four Corners (#136)	Convert from 230 to 345 kV operation.			Current	1998
Copy Interest: SRP						

California - Mexico Area

Project Type: Concept

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
CALP	Glass Mountain (#949)		49.9 MW Geothermal Power Plant		Current	2004
CALP	Sutter Power Plant (#717)		Interconnect new Sutter Power Plant (500 MW)to WAPA's 230kV Olinda-Keswick/Elverta lines. Switching Station will be built near these lines to interconnect the power plant.		Current	2000
SDGE	500kV line: Valley-Rainbow (#1271)	Concept project only - no funds committed yet.	Build a 62 mile 500kV line between SDG&E's Rainbow substation and SCE's Valley Substation. Loop TL23030 into Rainbow site, convert rainbow to 500 kV operation. (99123)		Current	2003
			Study Interest: Southern California Edison			
SDGE	AZ-CA 500kV Series Compensation (#488)		Conceptual project for one or more AZ-CA 500kV lines.		Current	
Copy Interest: Arizona Public Service Company						
SDGE	Transmission For Generation (#1273)	Reinforce SDG&E system. Project 99126. Concept project only.	Support the transmission requirements of a third party generator to connect to the SDG&E system. (99126)		Current	2002
WAMP	Elk Grove - Vaca Dixon T-Line (#911)				Current	
WAMP	Elk Grove / Tracy T-Line (#736)				Current	
WAMP	Sutter PP to Elverta Sub (#1255)		Sutter Power Plant to new substation near Elverta; A single circuit 230 KV line, approximately 29 miles.	$20,000,000	Current	2001
WAMP	Table Mt / Elverta 500-kV T-Line (#735)		This project can be studied in conjunction with, or without the Sutter Power Plant Interconnection Project.	$20,000,000	Current	

Project Type: Need

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
IID	IID 350MW Future Need (#472)		Need 350 MW of additional transmission capacity at unidentified locations.		Current	

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PG&E.	San Mateo-Martin No.3 Reinforcement (#463)	Serve forecasted load growth	Reconductor the San Mateo-Martin 115 kV No.3 circuit with 11.5 miles of 477 kcmil SSAC.		Current	2002

Project Type: Project

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
CALP	Los Medanos (#1390)		574,500 kW natural gas fired combined cycle power plant		Current	2001
Copy Interest: NCPA						
CALP	Metcalf Energy Center (#1389)		600,000 kW natural gas fired combined cycle power plant		Current	2003
Copy Interest: NCPA						
CFE	Cerro Prieto II #3 (#297)					
CFE	Cerro Prieto II #4 (#298)				Current	1999
CFE	Cerro Prieto III #3 (#294)				Current	1999
CFE	Cerro Prieto III #4 (#295)				Current	1999
CFE	Cipres to Rosarito II (#49)	Provide back-up transmission.			Current	1999
CFE	Imperial Valley CA to La Rosita MX (#161)	CFE - USA 230 kV ties.			Current	1998
CFE	Metropoli II to La Rosita (#165)				Current	1998
CFE	Metropoli to Rumarosa (#164)				Current	1999
CFE	Panamericana PDT (#159)				Current	1999
CFE	Rosarito II to Metropoli (#163)				Current	1998
CFE	Rosarito II to Tijuana 1 (#162)				Current	1999
CFE	Rumorosa to Tijuana 1 (#50)				Current	1999
CFE	Termoelectrica (#301)				Canceled	
CFE	Termoelectrica (#299)				Current	2003
CFE	Termoelectrica (#296)				Current	2000
CFE	Termoelectrica (#300)				Current	1999
CFE	Termoelectrica (#302)				Current	2000
CFE	Tijuana 1 to Miguel (#160)	CFE - USA 230 kV ties.			Current	2003
IID	KS 230 kV Line Loop into Ave. 42 Sub. (#142)	Loop Coachella-Mirage 230 kV into Ave42.			Current	1998
			The project consists of looping the existing Coachella Valley (IID)- Mirage 230 kV (SCE)"KS" line into the Ave.42 (IID) substation. The extension of the KS line will be a 2.5 miles of double circuit 2-1033.5 MCM ACSR conductor per phase. This project incl		Current	2000
LDWP	McCullough to Marketplace #2 (#158)					
Copy Interest: Arizona Public Service Company					Canceled	2007
PG&E	500 kV Transm. into Bay Area (#1403)	The Greater S.F. Bay Area is presently facing two compounding trends: rapid widespread loadgrowth and aging,retirement-bound fossil plants.	Increase the Bay Area 500/230 kV transformer bk. capacity,preferably locating the new bks. at a en entirely new site.		Current	2007
PG&E	Atlantic-Del Mar 60 kV Line Prj (#1259)	Atlantic-Del Mar 60 kV trans. line would experience normal overload in the Atlantic substation could experience low voltage during summer pk hrs.	Construct a second Atlantic-Del Mar 60 kV line.		Current	2001
PG&E	Bay Meadows 4/0 Cu Reconductor (#582)	Emergency overload is forecasted on the 4/0 Cu section of the San Mateo to Bay Meadows 115 kV circuits in the year 2000.	Reconductor the 4/0 Cu section approximately 2.5 miles from San Mateo to Bay Meadows tap with 715 kcmil Al.		Current	2003
PG&E	Brighton 230/115 kV Capacity (#1411)	Brighton 230/115 kV bank is projected to normally overload by 200.	Install a 2nd Brighton 230/115 kV Bank.		Current	2004
PG&E	Colgate 230/60 kV Capacity (#1413)	The existing Colgate 75 MVA 230/60 kV transformer could experience a 42% overload for loss of the	Add a second 230/60 kV ransformer at Colgate.		Current	2004

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		Marysville-Pease 60 kV line.				
PG&E	Cortina Substation Capacity (#1416)	The existing Cortina 230/115 kV 3-56 MVA transformer could experience a 10% emergency overload in the summer of 2003.	Replace the existing 3-56 MVA Cortina transformer bank with 230/115 kV, 420 MVA 3-phase units LTC's.		Current	2004
PG&E	Coyote Valley(CISCO) (#1241)	PG&E is currently proposing a new sub. to serve the proposed Cisco development which is still in the permitting process.	PG&E will build a new substation which would be looped into the Metcalf-Monte Vista #3 or 4 circuit.		Current	2001
PG&E	FMC Loop (#1459)	Additional bank capacity at San Jose A and B would defer need for 3rd FMC bank.	Loop FMC substation when the third distribution bank installed.		Current	2003
PG&E	Fulton-Lakeville Upgrade (#1432)	A gradual decline in Geyser generation and a increase in load demand will create a need for new resources.	Build new 230 kV facilities.		Current	2006
PG&E	Fulton-Monroe Tap 1&2 Line Reinforce. (#1111)	Fulton-S.Rosa 115 kV line outage(the other Fulton-S.Rosa 115kV feeds the total Monroe Sub.load.) Loading on 3.75 miles of 715 AL cond. between Fulton Sub.&Monroe tap.	Rerate the overloaded conductors. If rerate declined,recond.these line sections(with 477 (ACSS?)Develop operating solutions(curtail Geysers gen.)until EDRO.		Current	2001
PG&E	Herndon-Bullard 1&2 115kv Lines Recond (#515)	The Herndon-Bullard Nos.1 and 2 115 kV lines could experience an emergency overload during summer peak conditions. After loss of either circuit, the remaining line could be loaded up to 106% of its emergency rating.	Reconductor the Herndon-Bullard 115 kV DCTL with 477 kcmil SSAC conductors.		Current	2004
PG&E	Hostetter Substation (#556)	Distribution & Customer Services is planning to build a new distribution substation, Hostetter, in Northeast San Jose to provide service to expanding high-tech customers.	Construct 115/21 kV Hostetter Substation with one 45 MVA bank. Connect the substation to one of the Newark-Metcalf lines as a single tap.		Current	2004
PG&E	Humboldt-Arcata Third Line (#1433)	Low voltages due to an overlapping outage of Fairhaven unit and Humboldt-Arcata 60kV line.	Build new line.		Current	2004
PG&E	Hunters Point-Potrero 115 kV (#1423)	Install 115 kV cable to mitigate overloading on existing cables due to outages.	Install 115 kV underground cable between Hunters Point and Potrero PP switchyards.			2006
PG&E	Ignacio 230/115 kv Bank Relief (#1161)	An outage of the Ignacio 403 mva 230/115 kv transformer bank will sigificantly overload the remaining 230/115/60 bank at Ignacio.	Possible solutions include adding a parallel 403 mva 230/115 kv bank at Ignacio or drop load in the Marin and Vallejo areas.		Current	2004
PG&E	Jefferson 230/60 kv Bank (#560)	The 230/60 kV, 134 MVA transformer at Jefferson is expected to experience a 103% normal overload in the year 2001.	Replace existing 134 MVA transformer with a 420 MVA transformer in 2001 to avoid bank overload and to meet future load growth demand in the Peninsula area.		Current	2004
PG&E	Kerckhoff-Kerckhoffll Lines (#1417)	The Oakhurst Jc-Kerckhoff 1-2 lines are showing a normal loading of 100%.	Split existing Kerckhoff-Kerckhoffll 115 kV circuit into two circuits by 2001. Reconductor the Oakhurst-Kerckhoff-Kerckhoffll 115 kV circuit sections.			2003
PG&E	Lockefrd 60 kV Brker No. 32&52 (#1231)	Overloading of the Lockeford 230/60 kV transformer bank and area 60 kV lines.	Reconfiqure area 60kV lines to use an existing line as a 3rd to Industrial.		Current	2001
PG&E	Lone Tree Substation Interconnection (#627)	Future load growth in Diablo division's Delta District is projected to cause a need for additional distribution transformer bank capacity by summer 2002. Eastern Contra Costa County has experienced booming growth in residential developments in recent yea	To meet the forecast area load growth, the Lone Tree substation site is planned to be developed with the first 230/21 kV transformer bank placed in service by summer 2002 by looping into the nearby Contra Costa-Newark 230 kV line.		Current	2004
PG&E	Long Term Fresno (#1406)	The Greater Fresno Area has a heavy reliance or local hydro generation the avaibility of which is grealy influenced by weather and precipitation condition.	New transmission facilities could reduce the area's reliance or hydro generation and result in a more balanced and robust power supply mix.		Current	2006
PG&E	Long Term Stagg /Eight Mile Rd (#1233)	Low voltage problem in area for outage of Stagg-Tesla 230 kV line.	Loop Lodi-Stagg 230 kV line into Eight Mile Substation.		Current	2003
PG&E	Los Banos 500 kV Series Capacitors (#1192)	This project is not expected to increase capability of Path 15.	Replace 4-500 kV series capacitor banks between Los Banos and Midway that are approaching the end of their service life.		Current	2001
PG&E	Metcalf 4th 230/115 Transf. Bk (#1428)	The loss of one the three 230/115 transf. bks. results in thermal overloads of the summer emergency ratings on the remaining two trans. bks.	Install 4th 230/115 kV transformer bank at Metcalf substation.		Current	2003
PG&E	Metcalf Third 500/230 Bank (#1418)	Existing banks have serve emergency overloads.	Install a third bank at Metcalf Substaion.		Current	2002

PG&E	Metcalf-Monta Vista 4th 230kV Ckt. (#337)	For loss of the existing Metcalf-Monta Vista No. 4 230 kV circuit, overloads are forecasted for the Metcalf-Monta Vista No. 1&2 230 kV.	String the vacant circuit position with 2-conductor bundle 2300 AAC and install 230 kV line terminals at Metcalf and Monta Vista substations for 1999 summer operation.		Current	2001
PG&E	Morgan Hill Transmission Reinforcement (#1001)	Overlapping outages of a generator and a transmission line will cause overloads on the local Morgan Hill Transmission lines.	Loop Morgan Hill Junction-Green Valley 115 kV lines into Morgan Hill Substation.		Current	2003
PG&E	Mt. View-Whisman Loop (#1431)	Monta Vista-Ames 115 kV lines closed through would cause them to have normal(up to 5%) and emegency(up to 30%) thermal overloads.	Disconnect Ames Sub. from Mt.View -Whisman		Current	2001
PG&E	New Atlantic-Pleasant Grove #2 60 kv (#1154)	Emergency overload and low voltages at Pleasant Grove/ Lincoln area.	Add a new 60kv line from Atlantic to North of Pleasant Grove and feed Lincoln with new line. Install 18 mvar shunt Capacitor at Atlantic.		Current	2004
PG&E	New Clovis Substation (#1242)	DCS plan to build a new Clovis substation in the Clovis DPA by 2002.	This substation could be double tapped to the Barton-Sanger and Manchester-Sanger 115 kV lines.		Current	2003
PG&E	New Gold Hill-Clarksville 115 (#1246)	Emergency overload for loss of Missouri Flat- Gold Hill circuit.	Install new Gold Hill-Clarksville circuit and upgrade cap installation deleted.		Current	2001
PG&E	No. Livermore/Dublin Subs. (#523)	In 1999 thru 2004 the load is forecast to grow by 36 MW per year. As a result, substantial additions to PG&E transmission & dist. system will be required.	Construct 2 distribution subs.in No.Tri-Valley-Dublin and No.Livermore subs.		Current	2002
PG&E	Nortech 115/21 kV Sub. (#1240)	Load growth in the North East San Jose is exceeding normal capacity.	Perform inconnection study and seek management approval.		Current	2001
PG&E	Northeast San Jose Transmission Relief (#157)	High load growth and new business loads in the San Jose area may cause overloading of the existing transmission lines and the 230/115 kV transformers at Newark and Metcalf Substations.	Expand the new Los Esteros 115/21 kV Substation to include a 230/115 kV switchyard. Construct a new double circuit 230 kV transmission line from the existing Newark Substation to the Los Esteros Substation.		Current	2002
Copy Interest: Northern California Power Agency						
PG&E	Northern Receiving Station,Santa Clara (#531)	Due to a rapid load growth in the northern portion of the City of Santa Clara, the City is planning to construct a new 115 kV substation and rearrange 60 kV lines to provide a relief to the heavily loaded 60 kV North loop.	Construct a new 115/60 kV Northern Receiving Station (will be implemented by the City of Santa Clara) and loop-in existing PG&E Newark-Scott #1 and #2 lines to the new substation.		Current	2002
Copy Interest: Northern California Power Agency						
PG&E	Paradise Area Rein. Project (#1258)	Paradise Area is expected to experience emergency line overloads and low voltages.	Loop T.Mt.-Butte #3 kV line into Paradise and convert Paradise Sub. to 115 kV operation.		Current	2002
PG&E	Pinedale Distribution Sub. Inter. (#1156)	Herndon-Bullard line has a 13% overload if one circuit is out in the year 2001.	Install double tap to connnect Nees substation to Herndon-Bullard 115 kv line.		Current	2001
PG&E	Pittsburg-Tassajar 230 kv Recond. (#1170)	Forecast normal overload of 3% in 2001 summer peak.	Reconductor 5.4 miles of 954 AAC with 954 SSAC.		Current	2001
PG&E	Ravenswood 230/115kV Bk. Cap. (#1420)	A second bk. will be insall at Ravenswood to increase normal and emergency capacity to the Peninsula 115 kV system.	Ravenwoods Sub. Bk is the only transmission transformer bk. at this sub.Outage will cause other facilities in the Mid-Peninsula to exceed their emergency capabilities.		Current	2004
PG&E	Reactive Support in SF/B.Area (#1424)	Reactive margin in the Bay Area needs to be increased for contingencies.	Install reactive support in the Bay Area-candiate in Martin 230 kV for 2002.		Current	2003
PG&E	Replace 2 of 60's-70's 500kv Series Cp (#1149)	60's-70's vintage series capacitor banks are nearing the end of the service life.	Replace existing series capacitor banks with new bks. having normal/30 minute emergency rating of 2667 A/4000 .		Current	2003
PG&E	Replace nine 60-70's 500kV Cap (#1238)	60's-70's vintage series capacitor banks are nearing the end of their service life.	Replace with higher rated, MOV protected series cap bnks.		Current	2007
PG&E	RMR: Metcalf 500 kv 300 MVAR Cap Bk. (#1142)	The CISO has determined 6,000 mw of local reliability must run generation is needed for the SF Bay Area. The annual cost of this RMR requirement is about 500 million to 1 billion	PG&E Plans to investigate several transmission alternatives to reduce the 6,000 mw RMR requirement for Bay Area.		Current	2001
PG&E	Robles Station (#724)	Serve area load growth.	Single tap the Pittsburg-Moraga No.2 230 kv line and install one 45 MVA, 230/21 kv transformer.		Current	2002
PG&E	Salinas/Watsonville Transm (#1421)	Thermal overloads and low voltages are caused by	Install voltage support device in the Wasonville area		Current	2005

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		L-1 condition in the Watsonville.	to boost voltages.			
PG&E	San Francisco 230 kV Transmission (#497)	Potential reduced generation in San Francisco due to air quality constraints and increasing load lead to forecasted transmission deficiencies.	Various transmission options to replace Hunters Point Units 2 and 3 will be investigated. A proposed solution is to install a second San Mateo to Martin 230 kV cable plus possible additional East Bay upgrades.		Current	2005
Copy Interest: Northern California Power Agency						
PG&E	San Luis Obispo 70 Rein. Prj (#1268)	San Luis Obispo 70 kV area trans. will experience voltage problems and heavy line overloading 110-140% of summer emergency rating for several single line outages.	Install a 230/70 kV 150 MVA transformer bank at Templeton and construct a 0.5 mile 70 kV double circuit line from Templeton to Templeton Jct.		Current	2001
PG&E	Sonoma and Pueblo Voltage Support (#1112)	Unacceptable low emergency voltages are projected for Sonoma (100.5 kv)and Pueblo(103.2 kv) in the event of an outage of the Lakeville-Sonoma 115kV line in the summer peak 1999.	Install a 115 kV capacitor at Pueblo Sub. to be connected to its 115 kV bus. The capacity of the shunt capacitor is to be 100 mvar with 4 steps of 25 mvar each.		Current	2003
PG&E	Sonoma/Mendocino Coast Voltage Prj. (#1113)	Normal and emergency low voltage along the Mendocino coast.	Install voltage support device(shunt cap. bk, etc.) on the 60 kv Sonoma Coastal line.Convert the Philo Jct.-Elk 60 kv line to 115 kv rating and connect this line to the Ukiah-Hopeland-Cloverdale 115 kv line.		Current	2003
PG&E	St.Helena-Pueblo 115kv Line Rein. Proj (#513)	The 715 kcmil aluminum section of the St. Helena Jct.-Pueblo 115 kV line is projected to overload the summer interior emergency line rating of 146 MVA by 6%.	Rerate 14.64 miles of the 715 kcmil aluminum line section of the St. Helena Junction-Pueblo 115 kV line to 4 ft./sec. wind speed.		Current	2002
PG&E	Tracy/Tesla 500/230 kV Cap (#1394)	Tracy/Tesla 500/230 kV tranformers overloaded by 26% and 23% respectively.	Implement mitigations to relief Tracy/Tesla 500/230 kV transformer overloads.		Current	2001
PG&E	Tri-Valley Long Term Project (#1401)	Load growth in Tri-Valley will exceed existing capacity.	Install additional distribution substations and transmission.		Current	2002
PG&E	West Sacramento-Davis Rein. (#1404)	West Sacramento-Davis 115 kV experience emergency overloads due to 50 2/0 and 4/0 sections.	Reconductor the W.Sac-Davis 115 kV circuit or install a 2nd circuit.		Current	2004
PGEN	La Paloma Generating Project (#1050)		New 230 kV line (13 miles)		Current	2001
PGEN	Otay Mesa Generating Project (#1277)	Connected to Miguel-Tijuana 230 kV line 9 miles from Miguel.	2 Unit Combined Cycle Generating Plant		Current	2002
SCE	Alamitos & Lugo Wave Trap Rep. (#1269)	To relieve overloads on the Alamitos-Barre #1 & #2 230-kV lines, Alamitos-Center 230-kV line, Alamitos-Lighthipe 230-kV line, and the Lugo-Mohave 500-kV line.	Replace or remove four 230-kV wave traps at Alamitos substation, and one 500-kV wave trap at Lugo substation.		Current	2001
SCE	Mira Loma 500/230 kV Trf. Addition (#387)		Upgrade existing 500/230 kV transformer (AA-bank) at Mira Loma substation.	$11,160,000	Current	
Copy Interest: Southern California Edison Company						
SCE	Mira Loma [illegible] 230/66 kV Trf Add (#918)	To relieve overloads of Chino substation 230-kV transformer banks.	Add one 280 MVA 230/66 kV transformer and switchrack at Mira Loma substation.	$19,900,000	Current	1999
SCE	Mira Loma [illegible] 230/66 kV Trf Add (#12[illegible])	To relieve overloads of Chino substation 230-kV transformer banks.	Add one 280 MVA 230/66 kV transformer and switchrack at Mira Loma substation.	$10,000,000	Current	2000
SCE	[illegible] Capacitor Bank Additions (#12[illegible])	Correct excessive VAR deficits due to reduction of [illegible]	Add 1275-MVAR of shunt capacitor banks among 12 substations.		Current	2000
SCE	Serrano 500/230kV Trf. Add. (#1287)		Add third 1120-MVA 500/230-kV Tranformer Bank at Serrano substation.		Current	2000
SDGE	Bundle San Onofre-Talega #1 & #2 (#1076)	Serve load growth and increase import capability. 98190	Bundle TL23007 San Onofre-Talega #1, bundle TL23052 San Onofre-Talega #2.		Current	2004
SDGE	Convran: Sn Luis Rey, Sn Mateo (#1274)		Bundle TL23006 with TL13832 from SONGS to San Luis Rey, connect to second xfmr bank. Open TL13835 at San Mateo Tap. this project (99111) is being worked in conjunction with 99114, new xfmr at SLR sub.		Current	2000
SDGE	Expand 230kv at San Luis Rey (#1270)	99120	Loop 3-230kV tie lines into substation. install 230kV bus. convert TL13803 to 230 kV operation. (99120)		Current	2002
SDGE	Install Reactive Power Support (#1272)	Assist voltage support also. 99125	Install additional static and dynamic reactive power support, beyond what's being done on 99115. Install 100 MVAR STATCON at Talega, and additional 483		Current	2003

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			MVAR at various substations.			
SDGE	Install Transmission Substation Caps (#1189)	This is project 99115. More caps and a STATCON will be installed on another project, 99125.	Install additional substation capacitors to provide reactive power support		Current	2000
SDGE	New 138/69kV transformer, Mission sub (#1186)	Project 90151.	Replace 99MVA transformer with a 224MVA transformer at Mission Substation		Current	2000
SDGE	New 230/138 kV xfmr at Talega (#431)	To serve area load growth. 96155	Add pme 230 / 115 kV 392 MVA transformer at Talega Sub.		Current	1999
SDGE	New 230/69kV xfmr at Escondido sub (#1190)	99117	Install an additional 230/69 kV 224MVA transformer and remove an existing 138/69kV transformer at Escondido substation		Current	2001
SDGE	New 230/69kV xfmr,San Luis Rey sub (#1188)	99115	Replace an existing 60MVA bank with a new 224MVA bank at San Luis Rey Substation		Current	2000
SDGE	New Sycm. Canyon 230/69kV XFMR (#1269)	98195	Install an additional 230/69kV transformer at Sycamore Canyon Substation (98195)		Current	2002
SDGE	Recnduct. Laguna Niguel-San Mateo Tap (#355)	91167, now cancelled.	Reconductor two 138 kV lines		Canceled	2003
SDGE	Reconfigure 138kV south of SONGS (#1187)	Bundle existing transmission lines, reconfigure lines, add 2 new 230kV circuit breakers.	Reconfigure the 138kV Transmission system south of San Onofre		Canceled	2000
SDGE	South Bay - Main Street 138 kV Upgrade (#354)	Project 97167. To serve forecasted load growth	Upgrade 138 kV lines (10 miles)		Current	2001
SMUD	Pocket Sub. (#286)	Hedge-Pocket 230kV line looped into Campbell Sub.			InService	1998
TID	Walnut - Hilmar 115kV Line (#1296)		Construct 115kV double circuit line from Walnut substation to town of Hilmar. 230kV to 115kV transformation at Walnut.		Current	2001
TID	Westley - Walnut 115 kV Line (#1429)		Double circuit 115kV line from the Westley substation to the Walnut Substation with 230/115 kV transformation at Westley.		Current	2005
WAHQ	Cottonwood-Roseville 230 kV Reconductor (#343)	Increase import capability to Sacramento and voltage support	Reconductor 230 kV line (60 miles)		Current	
WALC	Davis-Parker 230 kV Reconductor (#376)		Reconductor 230 kV line		Current	2002
Copy Interest: Arizona Public Service Company, SRP						
WALC	Gila-Knob 161 kV Reconductor (#374)		Reconductor 161 kV line.		Current	2005
Copy Interest: Arizona Public Service Company, SRP						
WALC	Parker-Kofa-Gila 161 kV Reconductor (#377)		Reconductor 161 kV line		Current	2005
Copy Interest: Arizona Public Service Company, SRP						
WAMP	Lodi Interconnection (#1017)	Tie City of Lodi into WAPA's Hurley-Tracy 230-kV #1 line.	Tie City of Lodi into WAPA's existing Hurley-Tracy, California 230-kV #1 Line.		Current	2006
WAMP	O'Banion Substation (#727)		230KV Substation connecting Sutter Power Plant to WAPA's Olinda/Keswick/Elverta lines.		Current	2001

Northwest Power Pool Area

Project Type: Concept						
Org.	**Project Name and ID#**	**Need/Requirement**	**Project Description**	**Est. Cost (US$)**	**Status**	**Year**
BCHA	2L71 (conversion from 3L3) (#1455)	Replace ageing transformer; Serve increased loads.	Replace 360/13.8kV transformer at Wahleach GS with a 230/69kV transformer. Modify the 360kV ring at Rosedale for 230kV operation. Rename 3L3 as 2L71.	$4,430,000	Current	2009
BPA	Albany - Eugene Reinforcement (#894)	Depends on Halsey paper mill decision on energy supplier.	Add dbl ckt 115-kV from Eugene sub to Alderwood tap.	$3,340,000	Current	2001
BPA	Custer - Intalco Double Circuit (#895)	To serve 90 MW expansion at Intalco plant and other	Rebuild existing Custer - Intalco 230-kV line to dbl	$5,570,000	Current	

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		new industrial loads. Depends on loads materializing.	ckt.			
BPA	Z blank (#1302)		Non-electrical. Database test.		Current	2000
IPC	Borah-Midpoint Upgrade (#359)	Increase transfer capability of Borah West	Install 30% series compensation in the Kinport-Midpoint 345 kV line, reconductor the Brady-American Falls and the American Falls-Adelaide 138 kV lines, and add two shunt compensation banks.	$19,950,000	Current	2004
IPC	Southwest Intertie Project (SWIP) (#358)	Increase transfer capability for commercial purposes	New 500 kV Midpoint-Crystal T/L with 1200 MW bi-directional rating	$369,900,000	Current	2010
PSE	Christopher West Transmission Project (#805)		The project will involve rebuilding and re-routing existing 115 kV line between Christopher and Federal Way Area to support.	$2,250,000	Current	2008
PSE	N. King County Transformer Addition (#794)	The project is intended to provide additional suppon to meet the projected load growth in North King County area.	The project would involve installation of a 230 - 115 kV transformer at an existing or a new substation.	$10,000,000	Current	2006
PSE	Olympia Area Transformer Addition (#797)		The project will involve installation of a 230-115 kV transformer in either an existing or new substation in Thurston County.	$10,000,000	Current	2006
PSE	Pierce County Transformer Addition (#796)	The project is intended to provide additional capacity to serve the projected load growth in Pierce County and surrounding areas.	The project will involve installation of a 230-115 kV transformer at either an existing or new substation.		Current	2008
SNPD	Beverly Park 230-115kV Capacity (#661)	This project is needed to provide additional 230-115kV transmission substation capacity in the central Snohomish County service area (The 115kV part of this project is planned to be completed in 2005 and the 230kV in the year 2010).	This project expansion will require designing and constructing a 230-115kV transformation capacity at the existing Beverly Park 115kV switching station location in the south Everett area. This expansion will include a 230-115kV, 300MVA power transformer.	$4,410,000	Current	2010
SNPD	BPA SnoKing - Add 115kV Sectionalizing (#703)	This project is needed to reduce outage exposure for the south Snohomish County service area. An outage of the BPA SnoKing 115kV bus during winter peak conditions will result in a major non-cascading south Snohomish County outage.	The BPA SnoKing 115kV sectionalizing project would require the installation of one 115kV breaker in the BPA SnoKing substation. The BPA SnoKing substation is located near Maltby Road (208th S.E.) and York Road (35th Avenue S.E.). BPA addressed the 230kV	$500,000	Current	2001
SNPD	Lake Goodwin to Stanwood115kV Line (#639)	This project is needed to reduce the impact of a Sills Comer to North Stanwood outage. This project will reduce the outage exposure of three substations.	Construct approximately 10 miles of 115kV line between Lake Goodwin and North Stanwood substations. · Construct a 115kV line terminal at the Lake Goodwin substation. · Construct a 115kV line terminal at the North Stanwood substation		Current	2008
SNPD	Park Ridge Turner's Corner 115kV Line (#640)	This project is needed to provide an alternate transmission source that connects Park Ridge substation with Turner's Corner substation. This project will be coordinated with the Highway 9 road widening project sponsored by the WSDOT	Construct one mile of 115kV line connecting the Park Ridge and Turner's Corner substations.· Install a 115kV line terminal at Turner's Corner substation.·	$500,000	Current	2008
SNPD	SnoKing to Clearview 115kV Line (#690)	This project is needed to reduce the electric system exposure to outages in south Snohomish County. This project will increase the transfer capability between the BPA SnoKing and Snohomish point of deliveries.	Install a new 115kV power circuit breaker at SnoKing, construct a new 115kV transmission line from BPA SnoKing to the Floral Hills tap (1 mile), rebuild the Clearview to Tambark Junction tap 115kV line for double circuit (3.7 miles), install two power cir	$4,400,000	Current	2006
SNPD	Swamp Creek 115kV Switching Station (#641)	This project has been deferred, due to the deferral of a 230-500kV substation upgrade at BPA SnoKing and lower than expected peak demand growth.	The Swamp Creek switching station will include four 115kV breaker positions. The station will be designed to provide for one future 115kV breaker position and for future 230-115kV transformation.	$5,500,000	Current	2005

Project Type: Need

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
AVA	Avondale Substation (#1208)	115/13.8KV Substation	Add substation to meet increased loads in area		Current	2005
AVA	Ninth & Central Reconfiguratio (#1209)		Reconductor and reconfigure 2nd line into 9&C from Beacon		Current	2001

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AVA	Otis - Beacon 230 kV Line (#1436)		Reconductor/ build 230 kV line from Otis-Beacon			2008
AVA	Otis Orchards 230-115 (#1208)		Add 230-115 transformer to relieve overloading and improve reliability		Current	2004
AVA	West Plains Reinforcement (#1207)		Building tap to relieve overloads improve reliability		Current	2001
AVA	Wheatland Substation (#648)	115/13.8kV Substation			Current	2002
BCHA	LM Voltage Control (#1373)		Install two 230kV 2x110MVAR shunt capacitors (one set supervisory controlled; one set automativ vitage controlled) at ING and one 230kV 150MVAR reactor each at ING and MDn.	$9,990,000	Current	2007
BCHA	NLY Loop (#1457)	To accept higher delivery amounts of Columbia River realy Canadian entitlement at Nelway.	Terminate Cominco's 230kV transmission circuit 71L at Nelway. Add one 230kV breaker at Nelway.	$3,320,000	Current	2003
BPA	Monroe - Echo Lake Line #2 (#1321)	Increases N-> S transfers on the Northern Intertie	New 500kV line from Monroe to Echo Lake		Current	2003
GCPD	Priest Rapids Project POD (#1386)				Current	2001
PAC	Red Butte Transformer Project (#1283)	Install a 345-138 kV, 448 MVA Transformer at the Red Butte Substation in southern Utah.	Add 345-138kV, 448 MVA Transformer at the Red Butte Substation	$2,272,000	Current	2000
SPP	Falcon-Gonder 345 kV Project (#1014)		173 mile 345 kV line between Falcon & Gonder substations		Current	2003
Copy Interest: Resource Data International						
SPP	Frenchman Tap Project (#1016)				Current	2002

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Project Type: Project

Org.	Project Name and ID#	Need/Requirement	Project Description	Est. Cost (US$)	Status	Year
AIES	75 MVAr South Alberta Shunt Ca (#1347)		AIES Transmission Development Plan 2000-2009 Project 5		Current	2005
AIES	948L/9L948 SPTR (#1342)	AIES Transmission Development Plan 2000-2009. The recently completed single pole trip and reclose (SPTR) protection scheme implemented on 240 kV circuit 9L948/948L between Paintearth and Metiskow should help reduce the frequency of voltage collapse and no	Single Pole Trip and Reclose (SPTR) implemented on 948L/9L948		InService	1999
AIES	Air Liquide Fort Saskatchewan (#1365)		85MW Cogeneration		Current	2000
AIES	Balzac 240/138 Autotransformer (#1348)	Calgary's growth has produced a commensurate increase in the demand for electrical energy, and the interface between the 240 kV bulk grid and the underlying 138 kV transmission system which serves the city is beginning to reach capacity. At least one add	Balzac 240/138 Autotransformer and 240 kV In/Out		Current	2001
AIES	Bickerdike – Little Smoky 240 (#1356)	AIES Transmission Development Plan 2000-2009 Project 13	182 kilometres 240kV paralleling existing 138kV (approx. 115 mi)	$23,300,000	Current	2005
AIES	Calgary and Area Capacitors (#1338)		164 MVAr in total, comprised of 27 MVAr at Canmore 116S , 27 MVAr at Blackie 253S, 2x27 MVAr at Enmax #14 and 54 MVAr at Enmax #41. These capacitors increase operating flexibility and help address the reactive power deficiency in the Calgary area. All b		Current	2000
AIES	Calgary Area Thermal Upgrades (#1354)	Calgary's growth has produced a commensurate increase in the demand for electrical energy, and the interface between the 240 kV bulk grid and the			Current	2000

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		underlying [illegible] transmission system [illegible] the city is beginning to reach capacity. A number of rola			
AIES	Cancarb (#1362)		48MW Merchant Generation	Current	2000
AIES	Castle River (#1360)		50 MW Merchant Generation	Current	2000
AIES	Cordel – Vermilion 240 kV (#1357)	Includes Jarrow 240/138 kV transformation and Wainwright – Edgerton 138 kV	80 kilometres of 240kV construction and 38 kilometres of 138kV (approximately 50 and 24 miles respectively)	Current	2004
AIES	Edmonton - Calgary 500 kV x2 (#1355)	Edmonton - Calgary 500 kV Two Circuits (includes Pelgan – N. Lethbridge 240 kV and Balzac – Calgary Downtown 240 kV)	550 kilometres of 240kV construction (approximately 345 miles)	Current	2007
AIES	Ellerslie Synchronizers (#1341)		Need identified by Black Start Team to open up an additional system blackstart path from Fort Saskatchewan to the Lake Wabamun area	InService	1999
AIES	Fort McMurray – Lubicon 240 kV (#1358)	If local generators are unwilling or unable to participate adequately in this RAS implementation, the next stage of path expansion, involving construction of a new 240 kV line between Fort McMurray and the rest of the system, will need to be initiated.	180 miles 240kV construction.	Current	2004
AIES	Fort Saskatchewan Thermal Upgr (#1353)		EAL has identified that several transmission facilities may become overloaded under specific low-probability multiple contingencies (simultaneous generator and line outages) during the upcoming summer season. EAL's short term plan involves upgrading the	Current	2003
AIES	Hays 27 MVAr Capacitor (#1340)			InService	1999
AIES	Lloydminster Area Capacitors (#1339)		40 MVAr total, consisting of 20 MVAr at existing Hill 751S and 20 MVAr at a new POD substation planned for the Lloydminster area.	Current	2000
AIES	Lloydminster Area Generation (#1350)		50MW commercial generation under System Expansion Related Pricing (SERP) or other competetive procurement method	Current	2004
AIES	Lloydminster Area source (#1348)	The new POD will improve distribution service reliability to the city of Lloydminster, and will enable reconfiguration of the existing Hill source substation (Lloydminster) for increased operating and maintenance flexibility. The capacitors will support	New Lloydminster substation	Current	2000
AIES	Millenium (#1364)		220MW Cogeneration	Current	2000
AIES	Nevis 240 kV Bus Re-configurat (#1343)		The Nevis substation is presently configured so that auto-transformer failure will cause a simultaneous outage to transmission circuits 912L/9L912 and 9L920. This is an inadequate arrangement for critical transmission elements and it should be reconfigur	Current	2000
AIES	Northwest Generation 1 (#1351)			Current	2004
AIES	Northwest Generation 2 (#1352)			Current	2006
AIES	Nova Joffre Cogeneration (#1366)		470MW Cogeneration	Current	2000
AIES	Oldman River Dam (#1361)		21MW Merchant Generation	Current	2000
AIES	Rossdale (#1359)		206MW Merchant Generation	Current	2002
AIES	South Alberta Generation (#1344)	The Transmission Administrator's Development Plan 2000-2009 assumes that 250 MW of generation will be added in the Calgary area over the next two years, and a further 250 MW will be in place in the area by 2005. These generation additions will enable def	600 MW in total by 2007 in the Calgary area	Current	2007
AIES	Taylor Hydro Plant (#1363)		14MW Merchant Generation	Current	2000
AIES	UVLS programmes (#1345)		Undervoltage Load Shed Programmes south, east central, northwest, Empress and Cold Lake areas	Current	2000

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AVA	Benewah ID to Shawnee WA (#132)	Complete 230 kV loop in the Moscow-No. Lewiston area.			Current	2005
AVA	No. Lewiston ID to Shawnee WA (#129)	for Moscow-Pullman area load.			Current	1999
AVA	Rathdrum-Otis 230 KV (#1436)		Build double ckt line from Rathdrunm-Otis Orchards.		Current	2004
AVA	Shawnee to N. of Pullman (#206)				Canceled	2000
BCHA	1L17/18 Sub-Cable retiremement (#178)		Retire portions of two 138kV AC sub cables and overhead circuits. Retain radial supply from Vancouver Island Terminal to Saltspring and Galiano Islands.		Current	2001
BCHA	2L249 - East Kootenay Reinforc (#820)	Serve increased loads	Complete ROW acquisition and construct 230kV transmission line from Cranbrook and Invermere.	$32,240,000	Current	2006
BCHA	2L35 - Ingledow to Kidd#2 (#828)	Serve increased loads.	Design and construct 230kV double circuit transmission line between Ingledow and Kidd#2.	$28,880,000	Current	2009
BCHA	5L91/98 RAS Upgrade (#832)	Improve the reliability of this scheme in response to a WSCC finding identifying that failure of this RAS will have unacceptable consequence to the WSCC system.	Provide redundant communication to SEV & KCL for generation shedding and to CBK for TAUC line tripping.	$270,000	InService	2000
BCHA	ACK Voltage Control (#217)	Increase the station's firm capability to handle the increase station loading when the fifth Revelstoke generator is added.	Add 1 x 150Mvar shunt capacitor at 500kV bus.	$3,320,000	Delayed	2011
BCHA	ALH IPP Integration (#818)	Connect a new generating station, ALH (Arrow Lakes Hydro) to Selkirk.	Terminate a new 230kV line (constructed by Columbia Power Corp) from a new 170MW generating station (Arrow Lakes Hydro - ALH) at Selkirk.	$1,110,000	Current	2001
BCHA	CRK 5CX1 Refurbishment (#1089)	Replace ageing Series Capacitor Bank.	Replacement of all controls, protection and bypass breakers with modern equipment, replacement of the PCB capacitor cans with non-PCB filled cans, and replacement of power line carrier with microwave communications.	$7,760,000	Current	2001
BCHA	GUI 5CX1 (#1081)	Increase the Interior to Lower Mainland transfer capability for the addition of new generation in the South Interior.	Install new Guichon series capacitor station (GUI) on 5L87 between Kelly Lake and Nicola.	$21,100,000	Delayed	2011
BCHA	HVDC Pole 1 retirement (#177)	Retire HVDC pole 1 (312 MW) as contingent on expected end of life.	Derate to 0MW. 280MW on hot-standby.		InService	2000
BCHA	HVDC Pole 2 retirement (#179)		Derate to 240MW (1/2 pole).		InService	2000
BCHA	ICP IPP Integration (#826)		Construct two 138kV line taps on 1L103 and 1L104 circuits (JHT to EFM) to a new 240MW Island Cogen Project (ICP) generating station. Replace nine 138kV circuit breakers.	$2,280,000	Current	2000
BCHA	KLY Voltage Control (#1456)		Add a 500kV 125MVAR shunt reactor	$4,400,000	Current	2004
BCHA	MLS Series Cap Retirement (#1088)		Retire ageing series capacitor station for 5L11 & 5L12 (MLS I & MLS II).		Current	2003
BCHA	PAC IPP Integration (#1085)		Connect a new 240 MW generating station Port Alberni Cogeneration (PAC) to Port Alberni. Replace twelve 138kV circuit breakers and install a 138kV circuit breaker position.		Current	2003
BPA	Bonneville - Dalles Reinforcement (#887)	To relieve overloads due to outages on higher voltage network during high PDCI imports. Includes earlier Hood River - Bonneville 115-kV reconductoring project.	Reinforce 115-kV network between Bonneville and The Dalles. Includes line reconductoring and reactive support.	$4,400,000	Canceled	2000
BPA	East Seattle Reinforcement (#243)	Needed to increase reliability of serving growing Seattle Winter peak load and increase transfer capability to Canada.	Single ckt 500kV transmission line; 9.5 miles from Echo Lake to a tap on the Schultz - Raver #2 line, 3 miles from Raver. The 3 mile section to Raver will be operated open-ckt.	$17,700,000	Current	2002
Copy Interest: Seattle Department of Lighting (Seattle City Light)						
BPA	Franklin Area Reinforcement (#252)		Reconductor 115kV to 230kV	$5,500,000	Delayed	2007
BPA	Kitsap Area Reinforcement (#889)	Cost is BPA portion.	Rebuild Shelton - Kitsap 115-kV line to double-ckt 230-kV, one side operated at 115-kV.	$14,400,000	Current	2001

Copy Interest: Altec Industries						
BPA	N Seattle Tx Reinforcement (#259)	Need to increase reliability of serving Seattle Winter Peak Load	Add 500/230kV transformer bank at Sno-King Sub	$13,300,000	Current	2002
Copy Interest: Seattle Department of Lighting (Seattle City Light)						
BPA	Portland Area Reinforcement (#440)	Prevent voltage instability in Portland area during N-1 of several 500 kV T/L's.	380 MVAR caps at Keeler 500 kV bus		InService	1999
BPA	Portland Area Transformer Addition (#439)	Need to prevent overloading of existing transformers.	Add 500/230 kV transformer at Pearl sub.		Current	2003
BPA	Puget Sound Reinforcement (#244)	Prevent voltage instability due to loss of existing Chief Joseph-Monroe 500kV line.	New single-ckt Chief Joseph-Monroe 122 mile 500kV transmission line.	$100,000,000	Current	2008
Copy Interest: Seattle Department of Lighting (Seattle City Light), WSCC						
BPA	Salem Area Reinforcement (#1285)	Prevent overloads on existing line	Add 2nd sgl-ckt Santiam - Bethel Tap 230kV line	$7,794,000	Current	2003
BPA	San Juan Area Support (#898)	Prevents overloads after outage of existing 115-kV cable.	Replace 34.5-kV submarine cable with 69-kV cable.	$14,400,000	Current	2001
BPA	Schultz - Hanford 500kV Line (#1325)	Will relieve transmission constraint north of Hanford substation.	New 500kV line from Schultz sub to Hanford sub.	$54,400,000	Current	2005
BPA	Schultz - Puget Reinforcement (#304)	Prevent voltage instability in Puget Sound area.	Series compensation of Schultz-Raver dbl-ckt 500kV transmission line	$16,830,000	Current	2003
Copy Interest: Seattle Department of Lighting (Seattle City Light)						
BPA	Swan Valley - Teton 115kV #2 (#113)		New single-ckt 115kV line to parallel existing Swan Valley - Targhee - Teton 115kV line.	$13,300,000	Current	2000
BPA	Willamette Valley Reinforcement (#390)		Rebuild 71 miles of Big Eddy-Ostrander 500 Kv		Canceled	2007
CHPD	Coles Corner - Fox Canyon (#647)	Contractual limit of existing transmission line will be reached. Provides additional reliability by adding second line to area.	115 kV line from Fox Road to Coles Corner.	$3,390,000	Current	2004
CHPD	Monitor Substation (#1306)		115 kV switchyard and distribution sub.	$4,430,000	Current	2001
CLPD	Cherry Grove 115kV Switching Station (#305)	New power delivery point	Four breaker 115kV ring bus to integrate Battle Ground and Axford substations		Current	
CLPD	Hazel Dell 115kV Switching Substation (#306)	New power delivery point	Four breaker 115kV ring bus to integrate Ross and Stackford substations		Current	
CLPD	Lady Is. - Runyon 115 kV (#245)	To serve forecasted load	New 115kV line			
CLPD	River Rd. - Merwin/St.Johns 115kV (#246)	To integrate generation still under construction	New 115kV line (1.1 mile)		Current	1998
EDP	Dome to Bellamy, AB (#134)				Current	
IPC	Boise Bench - Locust (#362)	To serve forecasted load growth			Delayed	
			Construct Boise Bench-Locust 230 kV Line	$10,000,000	Current	2001
IPC	Brownlee - Oxbow (#1239)		Add a second Brownlee - Oxbow 230 kV Line to increase Brownlee North Capacity.	$8,600,000	Current	2004
IPC	Brownlee-Boise Upgrade (#357)	Increase Brownlee East transfer capacity by approximately 300 MW.	New 230 kV Brownlee-Paddock T/L (30 miles), upgrade Ontario-Caldwell to 230 kV, reconductor Paddock-Ontario 230 kV T/L, and series comp @ Ontario Sub	$31,100,000	Current	2001
IPC	Locust - Caldwell (#1101)	To serve forecasted load growth	Construct Locust-Caldwell 230 kV Line	$17,700,000	Current	2004
MPC	Helena Montana Reinforcement (#874)	Provide adequate support for the growing loads in the Helena area. With current system, not able to serve all the loads under a single outage condition.	Reconductor 100 kV lines (2) between Helena and Great Falls, Montana.	$8,870,000	Current	2003
MPC	Silver Bow Plant (#1410)		generation project			
PAC	Ben Lomond Capacitor Bank (#1052)				Current	2003
					Current	1999
PAC	K-Falls Generation Project (#1282)	The 500 MW combined cycle Klamath Cogen Project is located in southern Oregon. It consists of two Siemens Westinghouse 501FD combustion turbines each rated at 165 MW, and one 160 MW ABB single reheat steam turbine. Advanced combustion technology is utiliz	500 MW Combined Cycle Generating Plant		Current	2001
PAC	Miners to Foote Creek (#117)	PacifiCorp ownership.				
					Current	1999
PAC	Pinto Capacitor Bank (#1054)				Current	1999

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PAC	Spanish Fork Capacitor Bank (#1055)				Current	1999
PGE	Bethel 115-kV Substation (#904)	Provide new 115-kV bus	New 115-kV bus	$1,150,000	InService	2000
PGE	Bethel Bulk Power Transformer (#900)		Add one 230/115 kV, 252 MVA transformer at Bethel Sub.	$2,250,000	InService	2000
PGE	Bethel-Market Street 115 kV line (#388)		Provide an additional interconnection to PGE's Salem Area	$500,000	InService	2000
PGE	Blue Lake - Gresham 230-kV Line (#553)		Construct 9.0 miles of new 230-kV transmission between Blue Lake Substation and Gresham Substation	$3,395,000	Current	2009
PGE	Blue Lake Bulk Power Transformer (#116)	Integrate bulk power transformer.			InService	2000
PGE	Carver - McLoughlin 230-kV Line (#552)		Construct a new 230-kV transmission line between Carver Substation and McLoughlin Substation, total miles will be 5.0	$2,255,000	Current	2007
PGE	Carver Sub. bulk power transformer (#546)		Integrate new 320 MVA, 230/115-kV transformer	$4,410,000	Current	2005
PGE	Harborton bulk power transformer (#550)		Integrate a new 320 MVA, 230/115-kV bulk power transformer at Harborton Substation	$3,340,000	Current	2010
PGE	Market Street Sub. Conversion (#392)		Convert 57 kV system to 115 kV	$2,240,000	InService	2000
PGE	McClain Sub. conversion to 115-kV (#544)		Convert substation from 57-kV to 115-kV		Delayed	2013
PGE	Murrayhill Bulk Power Transformer (#540)		320 MVA, 230/115-kV transformer	$4,410,000	Current	2001
PGE	Oxford Substation conversion to 115-kV (#541)		Convert substation from 57-kV to 115-Kv	$1,127,000	InService	2000
PGE	Pearl - Sherwood #2 230-kV (#1461)		PGE & BPA plan to re-terminate the existing double circuit operating in parallel. This will require two new PCB. When completed there will be two circuits between Pearl(BPA) and Sherwood(PGE).	$2,220,000	Current	2004
PGE	Ruby Substation conversion to 115-kV (#542)		Convert 57-kV substation to 115-Kv	$1,117,000	Current	2002
PGE	Sherwood - Murrayhill 230-kV Line (#549)		Separate parallel operation of dbl. ckt. into individual ckts.	$1,160,000	Current	2006
PGE	Sherwood bulk power transformer (#551)		Install a third 320 MVA, 230/115-kV bulk power transformer at Sherwood Substation	$6,670,000	Delayed	2013
PGE	St. Marys-Wacker 115 kV Line (#366)	Reduce loading on existing lines	Construct new 115 kV line	$1,160,000	InService	2000
PGE	Sunset - Banks 115-kV Line (#547)		Construct a new 115-kV line with termination at Banks Substation via 125 MVA, 115/57-kV transformer.	$5,515,000	Canceled	2004
PGE	Swan Island Substation Conversion (#543)		Coonvert from 57-kV to 115-kV	$1,194,000	Current	2003
PGE	Willamette Valley Voltage Conversion (#545)	The conversion of the three substations to 115-kV will require a new 125 MVA, 115/57-kV transformer.	Convert three substations from 57-kV to 115-kV	$11,155,000	Current	2005
PSE	Intermountain (IP) 230 kV Project (#131)	Wanapum is adjacent to Vantage.	The project involves upgrading existing cross-Cascades IP 115 kV line to 230 kV operation.		Current	2010
PSE	Jefferson County 115 kV upgrade (#808)		The project involves upgrading existing 69 kV transmission to 115 kV. the project will resolve the existing overload of the 115-69 kV transformer at BPA Fairmount substation.		InService	1999
PSE	Jefferson County 115 kV upgrade PH II (#1096)		This project is a second phase of the Jefferson County 115 kV upgrade and it involves construction of a second 115 kV line between BPA Fairmount and PSE Irondale substations. The project will resolve the existing lack of transmission backup to the Port Tow	$2,250,000	Current	2001
PSE	Kitsap County Reenforcement (#119)	This project will provide additional transmission capacity to Kitsap County	This project consists of uprating existing transmission line to 230 kV operation and installing a 230-115 kV transformer at S. Bremerton substation.	$20,000,000	Current	2001
PSE	Lakeside - Center 115 kV transmission (#798)		The project involves construction of 5Miles of 115 kV transmission between Lakeside and Center substations located in Bellevue WA	$2,250,000	Current	2000
PSE	Novelty Substation development (#1334)		Initially, this project involves looping existing 115 kV		Current	2002

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			lines into Novelty. In the long term, the site will be considered for a 230-115 kV transformer addition.			
PSE	South King County Transformer Addition (#130)	This project provides additional support to South King County area load.	This project consists of rebuilding an existing transmission line between Talbot Hill - Berrydale (8 Miles) to 230 kV and installing a 230-115 kV transformer at Berrydale substation.	$13,300,000	InService	1999
PSE	West Kitsap Transmission Project (#799)		The project will involve construction of 115/230 kV line on a new R/W between Silverdale area and Foss Corner in Kitsap County.		Current	2004
SCL	Bothell Transformers (#1370)		Upgrade transformers at Bothell Sub.		Current	2002

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A Comprehensive Multipollutant Emission Control Strategy for Power Generation

Background

- There is continuing interest in a multipollutant strategy for control of air pollution from power generation.
- Most proposals focus on a multipollutant cap for old plants combined with increased NSR flexibility for compliance.
- A workable plan needs broader coverage, better results and greater flexibility.

2

The Clean Power Group

- Providing a voice for modern, efficient and low emitting generation in the formulation of new regulations for the power gen industry.
- Current members:
  - Enron
  - El Paso
  - Trigen
  - Calpine
  - NiSource

3

Goals of a Mulitpollutant Proposal

- Drive down multipollutant emissions from power generation overall.
- Reduce regulatory overhead for all parties.
- Minimize total control costs.
- Promote turnover to new, cleaner, more efficient technologies.

4

Basic Principles

- We need a more flexible approach.
  - NSR reform and trading
- All sources should be included.
- All sources should be treated the same.

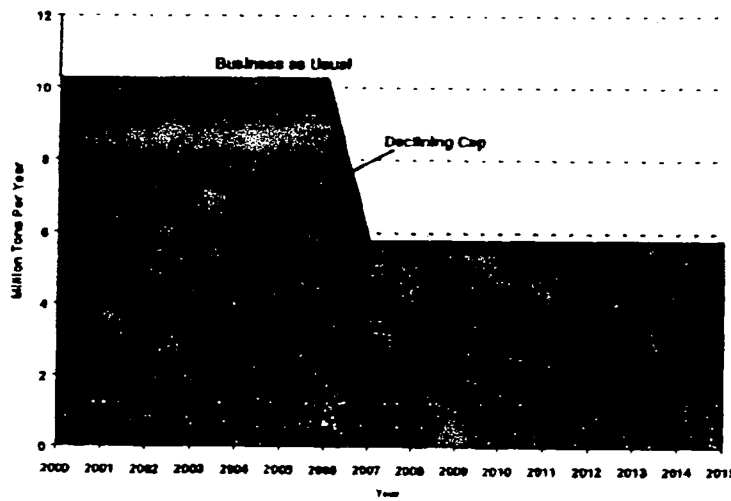
7

Summary of Approach

- Each pollutant is subject to an individual pollutant cap that declines continuously over time (glideslope).
  - NO_x, SO_2, mercury and CO_2 if desired
- No BACT/LAER or major modification review.
- Include <u>all</u> generators 1 MW or greater.
  - Simplified monitoring for sources < 25 MW.
  - Opt-in and aggregation for smaller generators.

8

Example of Declining Cap on SO_2



9

Approach (Cont)

- Direct credit for end use efficiency projects.
- Allowance trading for flexibility and cost reduction/equalization.
- Output-based allocation system to reward efficiency (include CHP).
- Retain NSPS and local impacts review.

10

Replacing BACT/LAER

- Ultimate goal of BACT/LAER is to reduce overall emissions over time.
- BACT/LAER is a roundabout method.
- Under a cap, BACT/LAER provides no environmental value since total emissions will remain the same.
- Declining cap gets the same result directly and more cost effectively.

11

Cap and Trade

- Cap provides greater environmental certainty than NSR.
- Provides greater flexibility and lower compliance cost.

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Historical Problems With Caps

- Difficult to find the right cap level.
- Cap incompatible with BACT/LAER
  - Defeats the cap function of reducing costs.
  - BACT/LAER have no environmental value under a cap.
- Doesn't include/support new, efficient generators.
- Allocation favors historic big polluters.

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Addressing the Problems with Caps

- Continuous declining cap on each pollutant provides continuing reductions and pressure on technology.
- Review of local impacts prevents hot spots.
- Frequent, output-based allocation to all sources supports new, clean technologies.

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Continuous Declining Cap

- Each cap decreases by fixed percent each year. Glide slope defined in advance.
- Decline for each pollutant stops if annual average allowance cost exceeds predetermined cost threshold ($/ton).
- Decline starts again when the annual average cost is below threshold by 10 percent.

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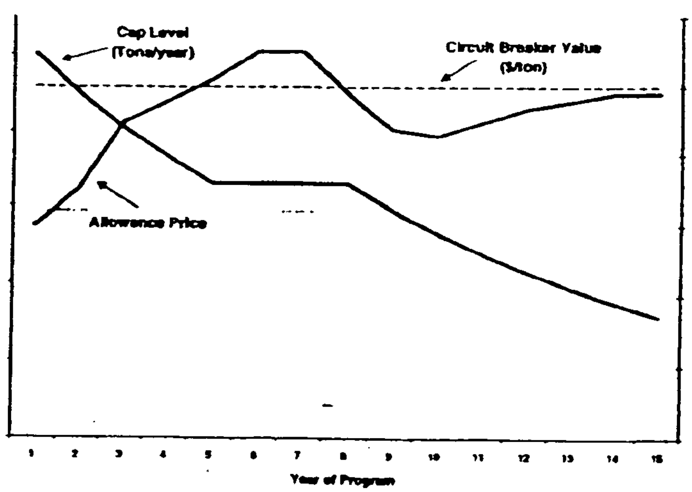
Illustration of Declining Cap



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Cost Circuit Breaker

- The cost measure is the previous year's average allowance price for an individual pollutant.
- Tightening of cap stops when the price exceeds the circuit breaker level.
- Cap begins to tighten again when the price is 10 percent below the circuit breaker level.

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Benefits of a Declining Cap

- Provides "meta-BACT" pollution reduction and technology-forcing function for the entire sector, not just new plants.
- Cost goal is similar to BACT but provides overall safety valve.
- Integrates market function into forcing function.
- Simpler than existing process with more certainty and flexibility for regulated entities.

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Other Sectors

- Non-power gen sources can create allowances if they are:
  - surplus
  - measurable
  - verifiable
  - enforceable

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Conclusions

- Multipollutant approach must include all sources.
- An all source, multipollutant program can:
  - Replace NSR
  - Provide better environmental benefits
  - Encourage new power development and infrastructure improvement.
- *More power, faster, cleaner, cheaper.*

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Addressing Today's Issues

- Expedite increased new generation with environmental security.
- Provides an option to address CO_2 without link to Kyoto or economic risk.
- Reform NSR.
- Better than enforcement actions.
- Support new generating technologies, renewables and conservation.

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To develop the database, staff first gathered information from various sources on proposed generation and retirements within the WSCC. These sources include discussions with staff at state regulatory agencies, visiting regulatory agency Web sites, reading energy industry newsletters (*Western Energy Update, Power Markets Week, Energy Insight,* and *California Energy Markets*), visiting company Web sites and telephone calls to project developers. Based on the information gathered, the projects were assigned, by status, to one of the following five categories:

1. Under construction or recently completed
2. Regulatory approval received
3. Application under review
4. Starting application process
5. Press release only

Summary

The table below provides a summary of proposed generation facilities within the WSCC region through the year 2007. The majority of the announced projects are plans for building natural gas-fired, combined-cycle plants. California and Arizona have the largest number of proposed facilities, totaling 19,419 megawatts (MW) and 16,875 MW, respectively. Please see the Energy Commission's siting/licensing cases page for complete details on the power plants licensing process in California.

WSCC Proposed Generation (in MW)

Status	Northwest	Southwest	Rocky Mountain	California-Mexico	Total
1	3,474	2,264	783	5,090	11,611
2	2,841	3,620	379	2,020	8,860
3	4,509	6,775	422	7,884	19,590
4	1,477	3,640	0	2,300	7,417
5	1,463	7,210	2,660	3,812	15,145
Total	13,764	23,509	4,244	21,106	62,623

By Location

Facility	Location	County	Status	Est Online Date	Output (MW)	Technology	Fuel Type	# of Units	Company	Notes	Source
La Paz	Arizona	La Paz	5	8/1/05	1080	Combined	Gas		Allegheny		Allegheny website
West Phoenix (Phase 1)	Arizona	Maricopa	1	8/1/01	120	Combined	Gas		APS/Calpine	Upgrade existing units	WEU/PMW/CEM
West Phoenix (Phase 2)	Arizona	Maricopa	2	9/1/02	500	Combined	Gas		APS/Calpine		Website
Redhawk 1	Arizona	Maricopa	2	1/1/03	530	Combined	Gas		APS/Reliant	Merchant/Est Groundbreaking 12/19/00	PMW
Redhawk 2	Arizona	Maricopa	2	1/1/03	530	Combined	Gas		APS/Reliant	Merchant/Est Groundbreaking 12/19/00	PMW
Mesquite Power	Arizona	Maricopa	2	3/1/03	1000		Gas		Sempra Energy Resources		Maricopa County Web
Redhawk 3	Arizona	Maricopa	2	6/1/06	530	Combined	Gas		APS	Merchant	PMW
Redhawk 4	Arizona	Maricopa	2	12/1/07	530	Combined	Gas		APS	Merchant	PMW
Arlington Valley	Arizona	Maricopa	3	8/1/02	500		Gas		Duke		CEM
Gila River	Arizona	Maricopa	3	12/1/02	2000	Combined	Gas		Panda Energy	ACC will consider at Jun 27-28 meeting	AZ Republic
Harquahala Generating Station	Arizona	Maricopa	3	9/1/03	1040	Combined	Gas		PG&E NEG	Merchant	PMA
Kyrene (Oasis)	Arizona	Maricopa	3	1/1/04	250	Combined	Gas	3-3-1	Oasis LLC		PMW
Gila Bend	Arizona	Maricopa	3	6/1/04	750	Combined	Gas		Power Dev Ent	Merchant/With Industrial Power Technology	AZ Republic
Santan	Arizona	Maricopa	3	12/1/05	825	Combined	Gas		SRP	Environmental Cert App submitted 7/17	www.santanfacts.org
White Tank Mountain	Arizona	Maricopa	4	1/1/07	1250	Pump Storage	Hydro	5	Arizona Independent Pwr		CEM
Mobile	Arizona	Maricopa	5	1/1/07	600				American Energy	www.maricopa.gov/envsvc/AIR/pwrplnt.asp	County Website
South Point	Arizona	Mohave	1	6/1/01	500		Gas		Calpine	Under Construction	WEU
Griffith Energy Project	Arizona	Mohave	1	7/1/01	520	Combined	Gas	2-2-1	Griffith Energy (PPL & Duke)	Under Construction	WEU/CEM
Caithness Big Sandy (Phase I)	Arizona	Mohave	3	8/1/02	500	Combined	Gas		Caithness	ACC Docket # L-00000R-00-0100	ACC Website
Caithness Big Sandy (Phase II)	Arizona	Mohave	3	12/1/03	220	Combined	Gas		Caithness	ACC Docket # L-00000R-00-0100	ACC Website
Desert Basin Generating	Arizona	Pinal	1	6/1/01	500		Gas		Reliant	Under Construction	WEU/CEM
Sundance Energy Project	Arizona	Pinal	4	8/1/02	600		Gas		PPL Global	Merchant Peaker	EPA Federal Register
Toltec Power Station	Arizona	Pinal	5	1/1/07	2000		Gas		SW Power Group II	1st phase estimated online in 2003	PMA
Los Medanos (Pittsburg) Facility	California	Contra Costa	1	7/1/01	500	Combined	Gas	2-2-2	Calpine	CEC Docket # 98-AFC-1 45% complete	CEC Website
Delta Energy Center	California	Contra Costa	1	7/1/02	880	Combined	Gas	3-3-1	Calpine & Bechtel	CEC Docket # 98-AFC-3 15% complete	CEC Website
Contra Costa	California	Contra Costa	3	5/1/03	530	Combined	Gas	2-2-1	Southern Energy	CEC Docket # 00-AFC-1	CEC Website
Potrero	California	Contra Costa	3	9/1/03	520	Combustion	Gas	2	Southern Energy	AFC expected 2000	CEC Website
CE Turbo	California	Imperial	1	6/1/00	10		Geothermal		CalEnergy	Under Construction	CalEnergy Web
Salton Sea V	California	Imperial	1	6/1/00	49		Geothermal		CalEnergy	Under Construction	CalEnergy Web
Sunrise Power Phase I	California	Kern	1	8/1/01	320	Simple	Gas	2-2-0	Edison International	CEC Docket # 98-AFC-4	CEC Website
La Paloma Phase I	California	Kern	1	12/1/01	521	Combined	Gas	2-2-1	PG&E NEG	CEC Docket # 98-AFC-2 40% complete	CEC Website
La Paloma Phase II	California	Kern	1	3/1/02	522	Combined	Gas	2-2-1	PG&E NEG	CEC Docket # 98-AFC-2 40% complete	CEC Website
Elk Hills	California	Kern	2	9/1/02	500	Combined	Gas	2-2-1	Sempra/OXY	CEC Docket # 99-AFC-1	CEC & Sempra Webs

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Pastoria	California	Kern	3	1/1/03	750	Combined	Gas	3-3-2	Southern Energy	CEC Docket # 99-AFC-7	CEC Website
Midway-Sunset	California	Kern	3	3/1/03	500	Combined	Gas	2-2-1	ARCC Western Energy	CEC Docket # 99-AFC-9	CEC Website
Antelope	California	Kern	4	2/1/04	1000	Combined	Gas		Enron	CEC Docket # 98-SIT-8; up to 1000MW	CEC Website
Sunrise Power Phase II	California	Kern	5	8/1/03	240	Combined	Gas		Edison International	Convert Sunrise I to a 580MW Combined	Edison Press Release
Hanford Energy Park	California	Kings	3	2/1/03	150	Combined	Gas	1-1-1	GWF Power Sys	Applied for small power plant exemption	CEC Website
Nueva Azalea (Sunlaw)	California	Los Angeles	3	8/1/03	550	Combined	Gas		Sunlaw Cogen Partners	CEC Docket # 00-AFC-3	CEC Website
Redondo Beach	California	Los Angeles	5	1/1/03	700		Gas		AES	AFC expected 2000	CEC Website
Long Beach District	California	Los Angeles	5	1/1/07	500		Gas		Enron	AFC expected 2000	CEC Website
Valley	California	Los Angeles	5	12/1/03	250	Combined	Gas		LADWP		
Haynes	California	Los Angeles	6	1/1/07	50	Combined	Gas		LADWP	Upgrades to existing plant	LADWP Press Release
Scattergood	California	Los Angeles	5	1/1/07	50	Combined	Gas		LADWP	Upgrades to existing plant	LADWP Press Release
El Segundo	California	Los Angeles	5	1/1/07	550		Gas		NRG & Dynergy		CEC
Moss Landing	California	Monterey	1	6/1/02	1060	Combined	Gas	2-2-1	Duke	CEC Docket # 99-AFC-4	CEC Website
Huntington Beach Modern.	California	Orange	3	6/1/01	450		Gas		AES	Expedited permitting process requested	CEC
Roseville	California	Placer	4	1/1/07	750		Gas		Enron		CEC
Mountain View Power Partners	California	Riverside	1	4/1/01	44	Wind	Wind	75	Seawest, Inc		Website 3/13/00 news
Blythe	California	Riverside	3	4/1/03	520	Combined	Gas	2-2-1	Summit Energy Group	CEC Docket # 99-AFC-8	CEC Website
Teayawa Energy Center	California	Riverside	5	12/1/03	600		Gas		Calpine	Located on Torres Martinez Desert Cahuilla	Company Website
Procter & Gamble	California	Sacramento	1	5/1/01	44		Gas		Sacramento Municipal	Under Construction 20% complete	CEC
Rio Linda/Elverta	California	Sacramento	5	1/1/07	500	Combined	Gas		Florida Power		CEC
High Desert	California	San Bernardino	2	1/1/03	720	Combined	Gas	3-3-3	Inland Group & Constellation	CEC Docket # 97-AFC-1; Const est 4/01	CEC Website
Mountainview	California	San Bernardino	3	5/1/03	1056		Gas		Thermo Ecotek	CEC Docket # 00-AFC-2	CEC Website
Otay Mesa	California	San Diego	3	1/1/03	510	Combined	Gas	2-2-2	PG&E NEG	CEC Docket # 99-AFC-5	CEC Website
Morro Bay	California	San Luis Obispo	3	10/1/03	1200	Combined	Gas	2-2-1	Duke	CEC Docket # 00-AFC-12 (Replaces 1,000MW)	CEC Website
United Golden Gate Peaking	California	San Mateo	3	6/1/01	48	Combustion	Gas		El Paso Merchant Energy	CEC Docket # 00-AFC-5 (4 month siting)	CEC Website
South City	California	San Mateo	4	4/1/04	550	Combined	Gas		AES	AFC expected 2000	CEC Website
Metcalf Energy Center	California	Santa Clara	3	3/1/03	600	Combined	Gas	2-2-1	Calpine & Bechtel	CEC Docket # 99-AFC-3	CEC Website
Three Mountain	California	Shasta	3	2/1/03	500	Combined	Gas	2-2-1	Ogden Pacific	CEC Docket # 99-AFC-2	CEC Website
Fourmile Hill	California	Siskiyou/Modoc	2	9/1/03	50		Geothermal		Calpine		BLM Website
Woodland Generation Station	California	Stanislaus	5	1/1/07	75		Gas		Modesto Irrigation		Sacramento Bee
Sutter Power	California	Sutter	1	7/1/01	500	Combined	Gas	2-2-1	Calpine	CEC Docket # 97-AFC-2 50% complete	CEC Website
Taylor Coulee Shute	Canada - Alberta		1	5/1/00	13	Hydro	Hydro	1	Canadian Hydro	Completed 4/27/00	WEU
Cowley Ridge	Canada - Alberta		1	8/1/00	2	Wind	Wind		Canadian Hydro	Complete	Website
Poplar Creek Ph 1	Canada - Alberta		1	9/1/00	290	Combined	Gas	2-2-0	TransAlta	Complete - Cogeneration Project/Suncor	Website
Joffre	Canada - Alberta		1	9/1/00	416	Combined	Gas	2-2-1	ATCO	Complete	PMW
Air Liquide - Scotford	Canada - Alberta		1	9/1/00	80		Gas		Air Liquide	Complete	Alberta resource
Cancarb Cogeneration	Canada - Alberta		1	12/1/00	47				TransCanada		Corporate Website

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Poplar Creek Ph 2	Canada - Alberta			1	1/1/01	70	Combined	Gas	0-0-2	TransAlta	Cogeneration Project/Suncor (Poplar Creek)	Website
Cavalier	Canada - Alberta			1	9/1/01	106		Gas		PanCanadian	www.resdev.gov.ab.ca/electric/rgeneral	Alberta Resource Dev
Balzac	Canada - Alberta			1	12/1/01	106		Gas		PanCanadian/CanOxy	www.resdev.gov.ab.ca/electric/rgeneral	Alberta Resource Dev
Oldman	Canada - Alberta			1	6/1/02	25	Hydro	Hydro		Atco Energen		Alberta Resource
Rossdale Unit 11 Repower	Canada - Alberta			1	9/1/02	170	Combined	Gas	1-1-0*	Epcor	**Will use existing steam turbine	Epcor Website
Muskeg River	Canada - Alberta			1	12/1/02	170	Cogeneration	Gas	2-2-0	ATCO	Part of Athabasca Oil Sands Project	Atco Website
Carseland Cogeneration	Canada - Alberta			3	11/1/01	80		Gas		TransCanada		Corporate Website
Grande Prairie	Canada - Alberta			3	3/1/02	20		WoodWaste		Canadian Gas & Elec	www resdev.gov.ab.ca/electric/rgeneral	Alberta Resource Dev
Cold Lake	Canada - Alberta			3	10/1/02	220	Cogeneration	Gas		Imperial Oil/?		Alberta Resource
Scotford	Canada - Alberta			3	1/1/03	150	Cogeneration	Gas		ATCO		Atco Website
Edmonton	Canada - Alberta			3	9/1/03	30	Cogeneration	Gas		Confidential	www.resdev.gov.ab.ca/electric/rgeneral	Alberta Resource Dev
Calgary Energy Centre	Canada - Alberta			3	12/1/03	250	Combined	Gas		Calpine	Name unknown - Plant is near Calgary	Reuters
Dunvegan	Canada - Alberta			4	12/1/02	40	Hydro	Hydro		Canadian Hydro		Alberta Resource
Syncrude - Ft McMurray	Canada - Alberta			4	1/1/07	238	Cogeneration	Gas		Syncrude Aurora	www.resdev.gov.ab.ca/electric/rgeneral	Alberta Resource Dev
Redwater Cogeneration	Canada - Alberta			5	11/1/01	40		Gas		TransCanada		Corporate Website
Island Cogeneration	Canada - British Columbia			1	10/1/00	250	Combined	Gas		Westcoast nrg	Under Construction	Website
Stave Falls	Canada - British Columbia			1	12/1/00	90	Hydro	Hydro		BC Hydro	*90 MW plant nets 38. Complete	Website
Port Alberni	Canada - British Columbia			2	1/1/07	240	Combined	Gas		ATCO	Delayed indef	WEU
Pingston	Canada - British Columbia			2	1/1/07	25	Hydro	Hydro		Canadian Hydro	Joint with Great Lakes Power	Canadian Hydro Website
Miller Creek	Canada - British Columbia			3	4/1/03	25	Hydro	Hydro		Miller Creek Power Ltd	RFP for BC Hydro	BC Hydro Website
Lytton	Canada - British Columbia			3	1/1/07	25		WoodWaste		Lytton power inc	RFP for BC Hydro	BC Hydro Website
Ashlu	Canada - British Columbia			5	1/1/07	25	Hydro	Hydro		Canadian Hydro		Canadian Hydro Website
Mamquam	Canada - British Columbia			5	1/1/07	25	Hydro	Hydro		Canadian Hydro		Canadian Hydro Website
Fountain	Colorado			2	6/1/00	215		Gas		Enron		PMW
Valmont	Colorado	Boulder		1	6/1/00	37		Gas/Coal	1	Black Hills	Complete	WEU
Arapahoe	Colorado	Cheyenne		1	6/1/00	74		Gas	2	Black Hills	Complete	WEU
Ray D. Nixon (Phase 2)	Colorado	El Paso		3	12/1/02	400	Combined	Gas		Coastal/CSU	Turbines purchased	Website
Manchief	Colorado	Morgan		1	5/1/00	265		Gas	1	Fulton/Coastal	complete	EIA
Fort St. Vrain	Colorado	Weld		1	6/1/01	235		Gas	1-1-0	PSC CO	Expand existing plant	PSC IRP 1999

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(Phase 3)	Colorado	Weld	1	6/1/01	235		Gas	1-1-0	PSC CO	Expand existing plant	PSC IRP 1999
Front Range (Ft Lupton)	Colorado	Weld	2	5/1/01	164	Combined	Gas		KN Power	Joint with Quixx (Peaker Unit)	WEU
Garnet Energy Facility	Idaho		4	7/1/04	250	Combined	Gas	1-1-1	Ida-West	Proposed to meet RFP from Idaho Power	www.ida-west.com/projects.htm
Rathdrum	Idaho	Kootenai	1	9/1/01	270		Gas	1	Avista	w/Cogentrix - under construction	WEU
Cerro Prieto IV	Mexico - Baja California		1	6/1/00	100	Geothermal	Geothermal		Mitsubishi	Under Construction	CFE
Presidente Juarez	Mexico - Baja California		1	5/1/01	540	Combined	Gas		Alstrom Power	Under Construction	CFE
La Rosita	Mexico - Baja California		2	4/1/03	750	Combined	Gas		Intergen	34% available for sale in US	Corp Press Rel
Ensenada	Mexico - Baja California		5	1/1/07	40			2		Expansion of existing plant	San Diego Union
Mexicali	Mexico - Baja California		5	1/1/07	257		Gas		AES	Announced 3/20/00	Energy Insight
Carbon County	Montana	Carbon	6	12/1/03	2000		Coal		Composite	Transmission to Wisconsin	WEU/PMW
Blackfeet I Wind	Montana	Glacier	3	10/1/01	22	Wind	Wind		Seawest Wind		Seawest Website
Blackfeet	Montana	Glacier	5	1/1/02	160		Gas		Adair	Merchant	PMW
Silicon Mountain	Montana	Silver Bow	5	9/1/03	500	Combined	Gas		BBI Power		
El Dorado Energy Project	Nevada		1	5/1/00	492	Combined	Gas		Sempra/Reliant	Complete/Merchant Plant/246mw to sempra	Website
Next Generation II	Nevada		4	1/1/02	30		Gas		Next Generation	Will ad 90 MW later	CEM
Nevada Green Energy Project	Nevada		5	12/1/02	150		Renew		Composite	Up to 1000 MW.Wind/Solar/Geo	WEU
Apex Industrial	Nevada		5	3/1/03	1000	Combined	Gas		Southern Energ		Website
El Dorado II	Nevada		5	12/1/03	480	Combined	Gas		Sempra/Reliant		CEM
Reliant/Pinnacle JDA (1)	Nevada		5	1/1/07	1400		Gas		Reliant/Pinnacle	Announced 3/14/00	Reliant Website
Meadow Valley	Nevada	Clark	4	3/1/04	1000	Combined	Gas		PG&E NEG		PMA Online
Moapa Paiute Generating Station	Nevada	Clark	4	1/1/07	760	Combined	Gas		Calpine		EPA Federal Register
Arrow Canyon	Nevada	Clark	5	6/1/03	500		Gas		Reliant		Reliant website
Carlin	Nevada	Elko	5	1/1/07	500		Gas		Coastal Power	Being considered	WEU
Washoe Energy Facility	Nevada	Washoe	5	12/1/03	600	Combined	Gas		Duke Energy NA		CEM 7/28/00
Cobisa-Person	New Mexico	Bernalillo	1	7/1/00	132	Combustion	Gas	1	Delta Power	Complete	WEU/CEM
Deming	New Mexico	Luna	3	12/1/02	550		Gas		Duke Energy Luna LLC		NM PRC Utility Division
Belen	New Mexico	Valencia	3	1/1/04	140		Gas		Cobisa	Merchant	www.cobisa.com/projects.htm
Albany Cogeneration	Oregon		1	7/1/00	85	Cogeneration	Gas		Willamette	Complete	EIA
Little Sandy Dam	Oregon		1	5/1/01	-11	Hydro	Hydro		Portland GE	Demolition in progress	WEU
Gilliam County Wind	Oregon	Gilliam	5	9/1/01	25	Wind	Wind		Seawest, Inc		WEU
Klamath Falls Cogeneration	Oregon	Klamath	1	7/1/01	500	Combined	Gas		PacifiCorp	Under Construction	www.klamathcogen.com/
Coyote Springs	Oregon	Morrow	2	6/1/02	280	Combined	Gas		Avista		Oregon Reg

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II	Oregon	Morrow	2	6/1/02	280	Combined	Gas		Avista		Oregon Reg
Hermiston	Oregon	Umatilla	1	6/1/02	546	Combined	Gas		Calpine	Purchased from Ida Corp & Trans Alta	Oregon Reg
State Line Project	Oregon	Umatilla	3	12/1/01	99	Wind	Wind		FPL Energy	Full application expected by Aug 2000	Oregon Reg
Umatilla	Oregon	Umatilla	3	12/1/03	550		Gas		PG&E Natl Energy	Adjacent to existing Hermiston plant	Oregon Reg
State Line Project	Washington		4	12/1/01	99	Wind	Wind		FPL Energy	See Oregon Stateline project	PMW 6/26/00
Mercer Ranch	Washington	Benton	4	1/1/07	850	Combined	Gas		Cogentrix		http://www.efsec.wa.gov/Default
Starbuck	Washington	Columbia	3	1/1/04	1100	Combined	Gas		PPL Global		WA State Web
Cowlitz Cogeneration project	Washington	Cowlitz	2	2/1/04	250	Combined	Gas	2-2-1	Weyerhauser		WA State Web
Goldendale	Washington	Klickitat	5	1/1/03	248	Combined	Gas	1-1-1	Nat. Energy Sys.		Oregonian
Chehalis Generation	Washington	Lewis	2	12/1/02	460	Combined	Gas	2-2-2	Tractebel		WA State Web
Northwest Regional Power	Washington	Lincoln	2	1/1/07	838	Combined	Gas	4-4-2	Northwest Power Ent	Reg approval 9/96.	WA Website
Satsop	Washington	Mason	2	6/1/03	500	Combined	Gas		Duke		WA State Web
Frederickson (Tenaska)	Washington	Pierce	1	6/1/02	249		Gas		Frederickson Power	Joint venture EPCOR and Westcoast energyr	PMA
Everett Delta	Washington	Snohomish	2	12/1/01	248		Gas		FPL Energy	Purchased rights from NW Power	WEU
Wallula	Washington	Walla Walla	3	1/1/05	1300		Gas		Newport Generation		
Sumas 2 Generating Facility	Washington	Whatcom	3	12/1/03	660	Combined	Gas	2-2-2	National Energy	Application No 99-1	WEU/State Reg
Gillette Upgrade	Wyoming	Campbell	1	6/1/01	40		Gas		Black Hills	Complete	Corp Website/EIA
Wygen I	Wyoming	Campbell	1	1/1/03	80		Coal		Black Hills	Under Construction	Corp Website
Foote Creek Wind III	Wyoming	Carbon	1	10/1/00	25	Wind	Wind		Seawest, Inc	25 MW to PSC CO - Project Complete	Seawest Website
Foote Creek Wind IV	Wyoming	Carbon	1	10/1/00	17	Wind	Wind	28	Seawest, Inc	Complete	WEU/Seawest website
Simpson Ridge	Wyoming	Carbon	1	12/1/00	10	Wind	Wind		Terra Moya		Energy Insight

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CALIFORNIA
ENERGY
COMMISSION

SUMMER OF 2001 FORECASTED ELECTRICITY DEMAND AND SUPPLIES

STAFF REPORT

NOVEMBER 2000
P300-00-006

1975 2000

STATE OF CALIFORNIA ENERGY COMMISSION

Gray Davis, Governor

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CALIFORNIA ENERGY COMMISSION

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ELECTRICITY ANALYSIS OFFICE

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Executive Director

2001 Summer Peak Demand/Resource Forecast
California ISO Control Area (MW)

Temperature Conditions		1 in 2	1 in 5	1 in 10
2001 Forecasted Peak Demand		47,266	48,845	50,068
2001 Forecasted Peak + 5% Operating Reserve		49,476	51,056	52,278
2001 Forecasted Peak + 7% Operating Reserve		50,303	51,882	53,104
2001 Peak Resources				
§ Existing Generation	45,025			
§ Firm New Additions	1,849			
§ Allowance for Outages	(2,500)			
§ California-Controlled Out-of-State-Resources	2,046			
§ Firm Imports	4,054			
§ Firm Exports	(725)			
§ Market Exports	(542)			
§ Excess Capacity From LADWP Control Area		1,222	898	832
§ Curtailable Load	2,150			
Total Resources		**52,579**	**52,255**	**52,189**
Total Potential New Additions	**1,888 — 3,087**			
Total Emergency Resources	**1,815 — 2,190**			

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

Potential New Additions

Huntington Beach 3 — 4 (return to service)	440
ISO CT RFB Projects	198 — 397
State of CA., Dept of General Services	
Distributed Generation - New Energy Efficiency Programs	200
U.C. Irvine Cogeneration	50
Imports: POWEREX (BC Hydro)	1,000 — 2,000
Total Potential New Additions	**1,888 — 3,087**

Emergency Resources

SMUD Cycling Program	100
Voluntary Load Curtailment	
California Grocers (Tested August 2000)	100
State of California (Tested August 2000)	180
Federal Govt., Cities & Counties, and Addtl. Grocers	120
Maximum output from existing generation	690
Emergency Assistance BPA (Per BPA)	300 - 400
Emergency Assistance WAPA (Per WAPA)	325 - 600
Total Emergency Resources	**1,815 — 2,190**

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Backup for ISO Summer 2001 Load-Resource Balance Table

ISO Control Area Load Forecast Summer 2001 With Peak Demand Adjustments*

	1 in 2 Year	1 in 5 Year	1 in 10 Year
(CEC Draft Forecast 10/16/2000)	47,486	49,065	50,288
Peak Demand Reduction Programs			
CPUC Public Goods Charge Programs	(67)		
CEC AB 970 (Dependable Savings)	(153)		
Adjusted ISO Control Area Load	47,266	48,845	50,068

*Loads include all municipal utilities except LADWP, City of Glendale, City of Burbank, and Imperial Irrigation District. Summer 2000 adjusted peak was 45,494 (August 16, 2000).

Calculation of Operating Reserves

Existing Generation	45,025		
CA Controlled Out-of-State Resources	2,046		
New Additions	1,849		
Allowance for Outages	(2,500)		
Available Generation	46,420		
Operating Reserve 5% of Avail. Gen.	2,210		
Operating Reserve 7% of Avail. Gen.	3,037		
Total Load + 5% Reserve	49,476	51,056	52,278
Total Load + 7% Reserve	50,303	51,882	53,104

California Controlled Out-of-State Resources

Palo Verde 1 —	
CA Utility Ownership Shares	
SCE	597
Pasadena	10
Riverside	12
SCE.Other	7
Vernon	11
Yuma Cogen	53
Four Corners 4 - 5	710
Total	1,400
Hoover	
CA Utility Entitlements	
Anaheim	40
Azusa	4
Banning	2
Colton	3
Metro Water District	248
Pasadena	20
Riverside	29
SCE	278
Vernon	22
Total	646
Total	2,046

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Firm New Additions
(Summer Ratings)

Los Medanos (7/1/01)	467
Sutter (8/01/00)	467
Sunrise CT (8/01/01)	285
Procter & Gamble CT - SMUD (6/01/01)	44
United Golden Gate CT (8/01/01)	45
Vineyard CT	47
Pleasanton CT	45
East Livermore CT	48
Chula Vista CT	37
Escondido CT	37
Incremental output from Existing Qualifying Facilities	80
Renewable Energy Projects (Existing CEC Program)	96
New Energy Renewable Projects (AB 970 Funding)	152
Total Firm New Additions	1,849

Firm Imports

Muni Owned Generation	
San Juan 3 - 4	273
Reid Gardner 4	180
Intermountain 1 - 2	414
Parker - Metro Water District	51
Total	918

Northwest Contracts	
BPA to CA Munis	230
BPA to SCE	500
Longview Fiber to Wstrn Mid-Pac.	43
Deseret G&T To CA Munis	92
Idaho Power to CA Munis	14
Boardman to TID	51
PNW Generating Co. to TID	52
PacifiCorp to Redding	50
PacifiCorp to SMUD	100
PacifiCorp NW to SCE	100
PacifiCorp Utah to SCE	100
PacificCorp NW to Wstrn Mid-Pac	250
PacificCorp NW to CDWR	200
Portland Gen. Elec. to SCE	300
Portland Gen. Elec. to SDG&E	75
Portland Gen. Elec. To Wstrn Mid-Pac	65
Puget Sound P&L to PG&E	300
Seattle City Light to NCPA	60
Seattle City Light to PG&E	100
Snohomish to SMUD	42
Tacoma PUL to Wstrn. Mid-Pac.	41
Wash. Water & Power to TID	18
Wash. Water & Power to PG&E	225
LADWP to CDWR	77
LADWP toTID	51
Total	3,136
Total Firm Imports	4,054

Firm Exports
(Existing Contracts and Non-ISO Ownership Shares of Mohave)*

Mohave to LADWP (Based on Summer Dep. Cap. Of 1387 MW)	(277)
Mohave to Nevada Power	(194)
Mohave to Salt River Project	(139)
SCE to Arizona Public Service	(5)
SCE to Tucson Electric Power	110)
Total Firm Exports	(725)

*ISO treats Mohave as a resource within their control area.

Derivation of Market Export Estimate

Net Imports On Stage II Days in 2000 at Hour of Peak Demand (Includes Out-of-Market Calls)		
Day	ISO Load	Net Imports
1-Aug	43,503	4,311
2-Aug	42,879	4,900
3-Aug	43,018	5,224
16-Aug	43,784	4,666
17-Aug	43,360	5,190
25-Aug	40,246	3,600
13-Sep	40,559	5,166
14-Sep	40,926	5,600
Ave. of Stage II days in August 2000 (A)		4,832

Ca. Controlled Imports	2,046
Firm Imports	4,054
Firm Exports	(725)
Net Firm Imports (B)	5,374

Estimate of Market Exports (B - A) **542**