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ASSESSING THE POTENTIAL ENVIRONMENTAL IMPACTS OF PROPOSED RULES AFFECTING FUTURE ELECTRIC POWER GENERATION IN THE UNITED STATES

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Energy Division

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Prepared for
Federal Energy Regulatory Commission

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ABBREVIATIONS

C	carbon
CAA	Clean Air Act of 1970
CO_2	carbon dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EIS	environmental impact statement
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FWS	U.S. Fish and Wildlife Service
GW	gigawatt
GWh	gigawatt hours
IFA	instream flow approximations
IPP	independent power producers
kg	kilogram
mg	milligram
MGY	million gallons per year
MPI	Maximum Potential Impact
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NOPR	Notice of Proposed Rulemaking
NO_2	nitrogen dioxide
NO_x	nitrous oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
ORNL	Oak Ridge National Laboratory
PSD	Prevention of Significant Deterioration
PUHCA	Public Utility Holding Companies Act
PURPA	Public Utility Regulatory Policies Act
QF	qualifying facility
SMCRA	Surface Mining Control and Reclamation Act
SO_2	sulfur dioxide
SO_x	sulfur oxide
TM	technical memorandum
TSP	total suspended particulates
WRC	Water Resources Council

PREFACE

This Technical Memorandum (TM) was prepared as an extension of work done at Oak Ridge National Laboratory (ORNL) during January and February 1988 for the Federal Energy Regulatory Commission (FERC). The initial work, which was not published by either FERC, ORNL, or the authors, was directed at helping FERC determine the scope of potential environmental impacts that could arise under proposed rules directed at future electric power generators in the United States. The motivation for the work is compliance with the National Environmental Policy Act (NEPA) of 1969, which requires federal agencies to consider potential environmental impacts of proposed actions in decision making. In accordance with NEPA, the work described in this TM evaluates the potential of the proposed rules to cause significant adverse effects on the human environment.

The results presented in this report were used by FERC in deciding that preparation of an Environmental Impact Statement (EIS) was warranted for the proposed rules. The draft EIS was issued in June 1988, and the final EIS was issued in November 1988. In the EIS, the potential impacts of the draft rules were examined under two scenarios: (1) large gas- and coal-fired projects are displaced by a mix of coal-dominated independent power producers (IPPs) (the high-coal scenario) and (2) large gas- and coal-fired projects are displaced by a mix of gas-dominated combined cycle plants (the high-gas scenario). Potential effects under each scenario were compared with potential impacts of a base-line scenario that projects fuel use trends without the rules. Relatively small changes in air emissions of sulfur and nitrogen oxides were predicted to occur under the rulemakings; under the high-coal scenario, CO_2 emissions were predicted to increase by 1.7% in the year 2000; under the high-gas scenario, national emissions of CO_2 were expected to decline by 2.2% in 2005. Based on the analyses in the draft and final EISs, no significant potential environmental impacts were identified for the rules.

SUMMARY

In 1988, the Federal Energy Regulatory Commission (FERC) began development of two rules with the potential to affect future electric power generation in the United States: one would prescribe minimum conditions under which competitive bidding may be used to establish rates for purchasing electrical power, and the other would reduce FERC regulations that interfere with the ability of independent power producers to produce and sell power. These rules, which would be issued simultaneously, could alter the fuel mix that supplies future electrical generating capacity projected by the utilities, which in turn could affect the environmental impacts of producing electric power. The rules must be issued in accordance with the National Environmental Policy Act (NEPA). This report has been prepared to evaluate the potential for environmental effects from future changes in fuel mix that could result from issuing the rules, and thus, in accordance with NEPA, to help the FERC determine if the rules would result in significant impacts on the human environment. Based on the results of this work, the FERC prepared and issued draft and final environmental impact statements (EISs) in 1988 while formally proposing the rules. As of December 1989, the rules had not yet been finalized.

Estimates of generating capacities in megawatts (MW) that could be affected by the rules were calculated on a state-by-state basis by deleting from the generating capacity projections the types of generating capacity not likely to undergo a change in fuel mix: nuclear, geothermal, planned peak or intermediate operation modes, units currently under construction, or units with a scheduled in-service date before 1993. Because the actual fuel mix that would supply the capacity affected by the rules cannot be predicted at present, it was assumed that coal use, which has the greatest potential for adverse environmental effects, would be encouraged by the rules, thus providing an upper limit of potential environmental impacts. Consequently, coal was also deleted because it is not a fuel type available to be shifted by the rules. Five states were identified as having projected capacities of about 1000 MW or greater that could be shifted to coal firing: California (1194 MW), New York (1700 MW), Oregon (794 MW), Texas (1300 MW), and Virginia (1292). Thus, potential impacts from a shift to coal of about 6,280 MW of capacity (7% of the approximately 88,000 MW planned to come on-line by 1996) were assessed for each of the states; potential impacts from supplying additional coal, burning it, and disposing of the combustion waste were considered. Because the California regulatory environment discourages new coal-fired generating units, it was assumed that the estimated generating capacity for California that might be shifted to coal would be located in the adjacent state of Nevada.

For estimating coal mining impacts, mining regions that supplied coal to the affected states in 1987 were assumed to supply coal for the period 1987-1996. Water-use, water-quality, and land-disturbance impacts were evaluated. Most impacts from coal mining were found to be small percentages of existing values. However, increased acid mine drainage into already severely impacted surface waters in the Appalachian supply region would require increased technical and regulatory attention to minimize impacts. Coal combustion could also cause adverse impacts on the environment. Waste disposal from power-plant operations is a significant sociopolitical issue in the heavily populated areas in the East, but state-of-the-art landfill designs

and strong regulatory controls should alleviate potential adverse environmental impacts. Projected air emissions (assuming all plants meet new source performance standards) of sulfur oxides (SO_x), nitrogen oxides (NO_x), and total suspended particulates (TSP) as a percentage of 1986 statewide emissions, were found to vary from 32% for SO_x in Oregon to less than 1% for TSP in all states. These projected emission increases could exacerbate air-quality problems (e.g., nonattainment of pollutant standards) observed in portions of these states in 1986. The estimated increase in carbon dioxide (CO_2) emissions would be a small percent of current emissions from fossil fuel combustion in the United States and thus offers little potential to significantly exacerbate global warming.

1. INTRODUCTION

1.1 BACKGROUND

Wholesale markets for electrical power in the United States are experiencing fundamental changes. The increasing importance of nonutility generation has been stimulated by the Public Utility Regulatory Policies Act (PURPA) of 1978 and by the need for investor-owned utilities to find alternatives to the construction of new capacities. At the same time, state regulatory authorities are seeking ways to ensure that a sufficient supply of reliable power is generated efficiently and priced appropriately. Some states have begun to use bidding programs as a mechanism for developing contracts for new capacities. Also, companies in the private (nonutility) sector have exhibited interest in entering the generating market as independent power producers (IPPs).

The Federal Energy Regulatory Commission (FERC, or the Commission) regulates the wholesale interstate trade of power under authority of the Federal Power Act (FPA). Under PURPA, FERC is required to govern rates for the purchase by utilities of power from qualifying generators. These generators, known as qualifying facilities (QFs), receive benefits such as a guaranteed market for power produced at rates equal to the cost utilities would incur if they generated that power themselves (avoided cost). IPPs are wholesale electric-power generators (other than QFs) that are not affiliated with franchised utilities in a given market area and that lack significant market power.

In 1988, in response to changes in wholesale markets for electric power, FERC was considering issuance of two Notices of Proposed Rulemaking (NOPRs). One (the "Bidding rulemaking") would establish minimum requirements for competitive bidding programs under which electric power can be purchased from QFs. The second rulemaking (the "IPPs rulemaking") would streamline the regulation of a class of non-QF IPPs that lack significant market power, thus ensuring that FERC regulations do not interfere unduly with the ability of IPPs to produce and sell electric power.

1.2 PROPOSED RULEMAKING

The proposed action is to issue two sets of regulations (or rules), one that sets guidelines for competitive bidding, and one that revises FERC regulations concerning IPPs. Although each rulemaking can be considered an independent action, the interactions that result from the two regulations could be important.

The first rule would authorize state regulatory authorities and nonregulated utilities to implement bidding procedures as a means of establishing rates for power purchases from QFs under Sect. 210 of PURPA. Although bidding is optional and great latitude is given to the implementing authority (e.g., a state or nonregulated utility) to determine the details of a bidding system, minimum binding conditions are prescribed by the proposed rule. The general intent of the guidelines is to ensure that all potential sources of supply are taken into account when rates for QFs are set.

The second rule would streamline regulation of IPPs by (1) allowing rates for IPPs to be determined through negotiation or bidding, subject to a

price cap; (2) authorizing IPPs to file rate schedules without having to provide extensive cost data to support them; (3) exempting IPPs from cost-related accounting, reporting, and recordkeeping requirements; (4) providing for blanket prior authorizations to engage in certain corporate activities; (5) revising filing fees; (6) waiving annual charges; and (7) adopting an advance-certification procedure by which an independent producer can qualify as an IPP.

The IPPs rule would not, however, diminish regulation of IPPs by the Securities and Exchange Commission under the Public Utility Holding Company Act (PUHCA). FERC has no authority to license or authorize the construction of IPPs or to waive any state law or regulation concerning siting, zoning, land use, or environmental compliance.

1.3 ALTERNATIVES TO RULEMAKING

The available alternatives that could meet the objectives of the proposed action must minimize both the uncertainty associated with the implementation of state bidding programs and the unnecessary regulation of IPPs. Because FERC has power only to interpret and administer statutes written by Congress, acceptable alternatives are limited.

1.3.1 No-Action Alternative

FERC could ignore issues raised by the proposed rules. Current market forces and state regulatory trends favor the goals underlying FERC's NOPRs. As a result, IPPs will be built and many states will institute bidding programs without further action by FERC. However, fewer IPPs may be developed if FERC takes no action. Similarly, bidding programs would probably develop more slowly, and in fewer states, under the no-action alternative because of uncertainties concerning the minimum elements needed to comply with PURPA. Furthermore, taking no action at all may become increasingly difficult as state regulatory authorities, QFs, IPPs, and utilities submit individual complaints and requests to FERC.

1.3.2 Case-by-Case Action

Even if FERC takes no action regarding bidding and IPPs, disputes will arise concerning the validity of avoided-cost rates determined through state-implemented bidding plans, and IPPs will request exemption from reporting and other requirements under the FPA. The policies effected in individual cases brought before FERC will eventually establish a series of precedents. Resolving these issues on a case-by-case basis will cause delays and will decrease the likelihood that a rational and coherent policy will emerge.

1.3.3 Policy Statement

Another alternative to the proposed action is for FERC to issue a nonbinding policy statement to explain its position on relevant issues. Such a policy statement might alleviate some of the uncertainty regarding the legality of bidding, and it would encourage IPPs to apply for waivers of the FPA's requirements on a case-by-case basis. It might also interfere less with existing bidding programs. Such a policy statement, however, would not carry the authority of a rule and could be changed without notice or comment.

Without the assurance an actual rule could provide, interested parties would be less willing to invest in new IPPs, and authorities would be less willing to implement competitive bidding programs.

Postulated alternatives to the rulemaking (policy statement and case-by-case considerations) would have much lower potentials for significant effects because they are nonbinding and have low potentials to affect the electric generating industry. With no action, impacts will result from the fuel mix postulated by the utilities during the 1987-1996 time frame.

1.4 SCOPE OF ASSESSMENT

1.4.1 Bidding/IPPs Relationship

The potential environmental impacts of future electric power generation are strongly related to the type of fuel projected to be used to produce the electric power (e.g., nuclear vs coal vs hydro) in various regions of the United States. The potential for environmental impacts from the rules is thus in turn related to the possible change in fuel mix from that projected by utilities for various regions of the country. Under the rules, voluntary bidding by states is an alternative to administrative determination of capacity payments to qualifying facilities. Figure 1 illustrates the status of bidding programs throughout the United States as of September 1987. A number of states are either conducting or considering bidding programs, and the net effect of the rule may be small compared to the baseline (i.e., states likely to implement bidding after the rule is finalized already may be implementing or considering bidding).

The bidding rule potentially could affect the fuel mix used for electrical-energy generation in a number of ways. Characteristics of the rule that could influence potential effects include (1) efficiency standards (percent of energy of the fuel that must be converted to MW of electricity) would be waived for oil- and gas-fired QFs that win bids; (2) fuel diversity would be encouraged as a nonprice criterion in a bidding program; (3) IPPs may be encouraged to develop because they would receive benefits (capacity payments); and (4) IPPs located at existing industrial and commercial sites may be more likely to win because their capital costs may be significantly or fully depreciated (nationwide, FERC estimates that 13 to 15 GW of electrical-generating capacity is available at non-QF industrial facilities). Quantifying the nature and extent of the impact these factors have on future fuel mixes is difficult using available data. Factors (3) and (4) are more likely to affect fuel mix if state regulatory authorities and nonregulated utilities allow IPPs to participate directly in bidding programs. Even if states and nonregulated utilities are not influenced by the bidding rule, IPPs could still be created by negotiated sales to utilities outside the context of bidding. For the purpose of this assessment, bidding is assumed to result in a negligible effect on fuel mix, when the IPPs rule is issued concurrently with the bidding rule.

1.4.2 Geographic Coverage

The geographic coverage of this assessment includes all 50 of the United States. However, electric power generators in the states of Alaska, Hawaii, and Texas do not significantly participate in the sale of power in interstate trade. As a result, electric power producers in these states are not

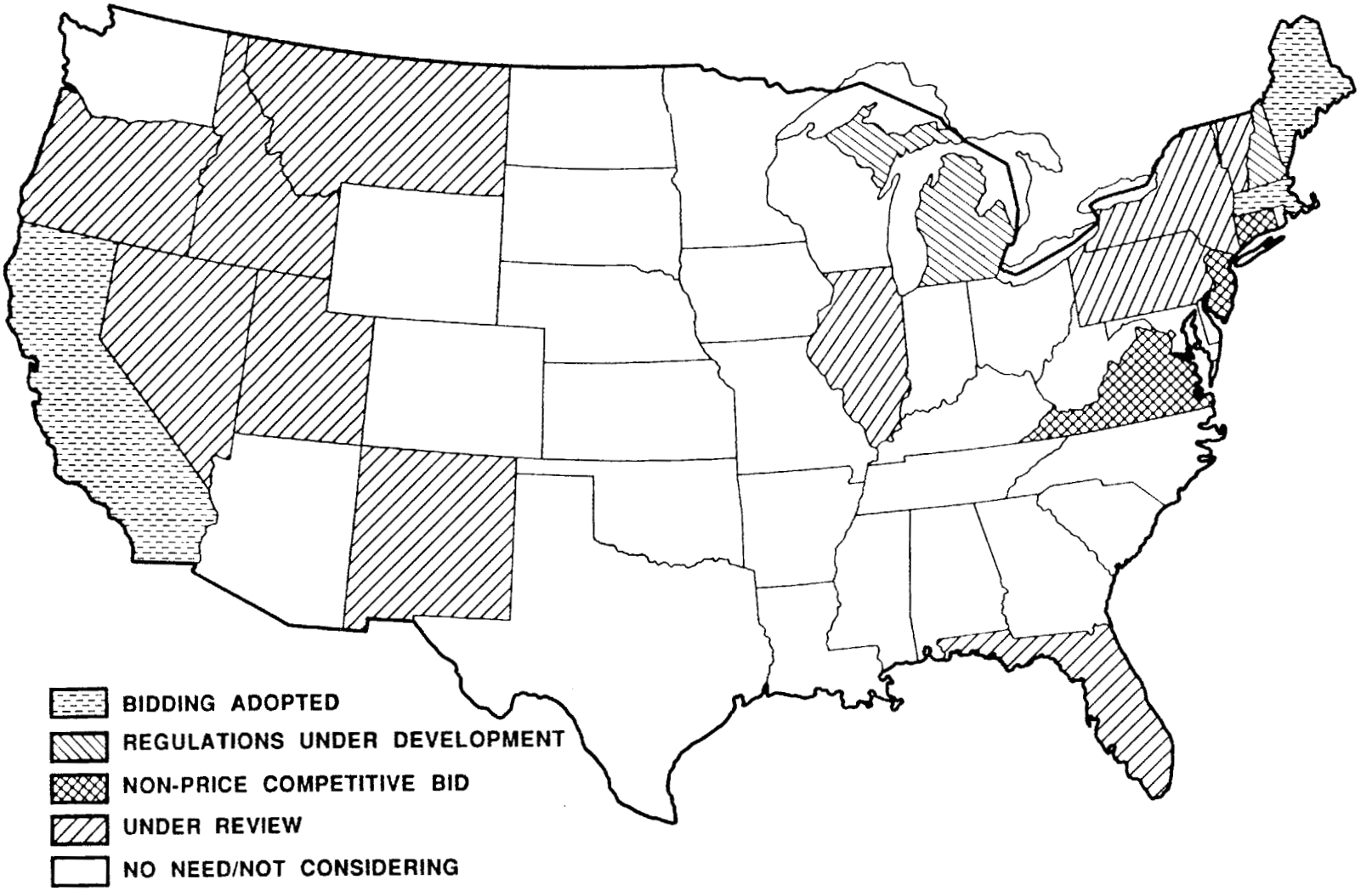

Fig. 1. Status of state bidding programs as of September 1987.

Source: National Independent Energy Producers, *Pricing New Generation of Electric Power: A Report on Bidding*, NIEP, Washington, D.C., September 1987.

regulated under the FPA, and the rule on independent power producers is not relevant. The rule governing competitive bidding remains relevant, however, because it is based on PURPA rather than FPA.

1.4.3 Time Frame

The assumed time frame for this study is from 1987 to 1996. These years were selected because they correspond to the utility-planning time period for the data on forecasted capacity needs and fuel mixes that were available at the time of this study. Utilities are only required to project capacity needs and fuel mixes for a ten-year period. These data are reported by utilities to the North American Electric Reliability Council (NERC) and to the Energy Information Administration (EIA) of the U.S. Department of Energy. Current utility projections of generating capacities and fuel mixes are used to assess the impacts of the rulemakings. The rules potentially would affect the environment as long as they remain in effect. The greatest potential for net change over baseline conditions, however, is in the first few years after the rules are issued. For longer-term time frames, there is an increasing probability that other factors (as yet unforeseen) may influence the electric power generating industry, thus diluting the effect of the rules on the net change in environmental impacts from the baseline to some future year.

1.4.4 Issues Addressed

Site-specific impacts cannot be predicted for the rules. There is no information available as to where IPPs and non-IPPs generating plants would be located as a consequence of these rules. Therefore, this study is not concerned with the environmental impacts of building and operating individual electric-generating plants at specific sites. Specific projects will be developed in accordance with the rules in consideration of Federal, State, and local environmental requirements germane to a particular site. Environmental impacts will be determined by the application of existing rules at particular sites. Appendix C summarizes some of the requirements that pertain to power plants in key states of interest.

As explained in Sect. 2, the actual fuel mix that will result from the implementation of the rules cannot be accurately predicted. Consequently, the majority of this assessment is based on a scenario of maximum potential impact in which the rules are assumed to shift the fuel mix toward coal. In the coal scenario, regional issues of principal interest are air quality, water quality, water use, and land use. Potential impacts from coal mining and power-plant operation are considered.

1.5 AGENCY RESPONSIBILITY

To assess the potential environmental impacts of the proposed rules, the staff assumed the rules would be translated immediately into new power plants of a particular fuel-type that are located in particular regions. The proposed FERC rules would affect only the economic incentives of building and operating power plants. Other significant problems must be rectified to successfully build and operate a power plant (e.g., requirements of the PUHCA and Federal and State environmental permits).

2. ANALYSIS

2.1 APPROACH

Present projections by the electric-utility industry (NERC 1987) indicate that, from 1987 to 1996, approximately 87,600 MW will be added to the electrical-generating capacity of the United States. The proposed rules are intended, in part, to encourage IPPs to help supply this incremental capacity.* If this occurs, environmental effects might arise through changes in the fuel/technology mix that would be favored by the IPPs if the rules were implemented. Impacts from the proposed action can be evaluated by comparing conditions under a no-action scenario with those that might arise under a maximum potential impact (MPI) scenario. The no-action scenario corresponds to conditions in 1996 under the currently projected fuel/technology mix contained in NERC (1987). The MPI scenario would occur only if the proposed action drove fuel choices and technology decisions towards those that have the greatest potential for adverse environmental impacts. Coal-fired power generation technology would likely be the most adverse technology employed by IPPs--as opposed to gas, oil, or clean coal--because of the combined impacts of coal mining and combustion (FWS 1978).

2.2 FUEL SCENARIOS

The following sections describe the no-action and MPI scenarios used to evaluate the impacts of the proposed action. Potential impacts of the proposed rules are assessed by developing an MPI scenario in which impacts are incremental to those under the no-action baseline.

2.2.1 The No-Action Scenario

Table 1 summarizes the capacity additions to the U.S. electrical generation base for the period from 1987 to 1996 on a state-by-state basis, excluding Alaska, Hawaii, and Texas. These data are derived from NERC (1987) and represent the current planning perspective of the U.S. electric-power industry in terms of capacity-addition requirements and the probable fuel/technology mix that will be involved. The fuels specified in the NERC data comprise the following general categories:

nuclear;
hydroelectric and pumped storage;
geothermal;
coal;
oil;
natural gas; and
other (solar, wind, refuse, etc., and unspecified fuels).

---

*It is assumed that the rules will not significantly affect the amount of generating capacity (MW) projected by the utilities.

Table 1. Projected U.S. electric generating capacity additions (MW) for the period 1987-1996 by state and fuel/technology for the conterminous United States and Alaska[a]

State	Nuclear	Geo-thermal	Coal	Oil	Gas	Other	Hydro	Total
Ala.	2,424		1,457	100	100		120	4,201
Alaska[b]				79	77		36	193
Ariz.	1,270		1,060[b,c]			50	105	2,485
Ark.							17	17
Calif.		974			1,198	3,778	1,074	7,024
Colo.		10	1,088		195	1	31	1,325
Conn.							13	13
Fla.			1,515	1,163	1,247			3,925
Ga.	2,142		1,641				378	4,161
Idaho						50	127	177
Ill.	4,250							4,250
Ind.			1,300	240				1,540
Iowa				50				50
Ky.			1,095					1,095
La.				540				540
Mass.					238		24	262
Md.			717	113		35		838
Me.							52	52
Mich.	1,093				1,225	188		2,506
Minn.			851				12	863
Mo.			955	50	249			1,254
Miss.			250					250
N.C.	900		690					1,590
N.H.	1,150							1,150
N.J.*					753[c]	2,183[d]		2,936
N.M.			1,000[a]	74[a]			52	1,126
Nev.			1,725	140	420			2,285
N.Y.	1,889				170	1,098	1,539[e]	4,696
Ohio	2,358		1,300		15			3,673
Okla.			300	170	100			570
Oreg.						24	859[f]	883
Pa.*	1,875		667		166	630	31	3,369
R.I.				1	420			420
S.C.					444	136	1,000	1,580

Table 1. (continued)

State	Nuclear	Geo-thermal	Coal	Oil	Gas	Other	Hydro	Total
Tenn.	2,340							2,340
Tex.	4,800		5,315		2,865	1,320		14,300
Utah		45[g]	1,220[h]	14	12		11	1,302
Va.					185	1,292	6	1,483
Vt.					210		8	218
Wash.						47	63	110
Wis.			60	5		29	54[i]	148
W. Va.			59				29	88
Wyo.							21	21
*N.J.+Pa.	1,875		667		919	2,813	31	6,305

[a]All data (unless noted otherwise) are from North American Electric Reliability Council (NERC), *Electricity Supply and Demand for 1987-1996*, Princeton, N.J., 1987.

[b]Energy Information Administration (EIA), *Inventory of Power Plants in the United States, 1986*, DOE/EIA-0095 (86), U.S. Department of Energy, Washington, D.C., 1986.

[c]350 MW from EIA 1986.

[d]440 MW by General Public Utilities might be split with Pa.

[e]1465 MW by General Public Utilities might be split with Pa.

[f]Includes 450 MW from EIA 1986.

[g]844 MW is U.S. Army Corps of Engineers.

[h]Only 45 MW found in NERC 1987.

[i]Includes 420 MW from EIA 1986.

[j]Includes 48 MW from EIA 1986.

Capacity additions in the no-action scenario between 1987 and 1996 are assumed to correspond to the fuel/technology mix indicated in Table 1.

2.2.2 The Maximum Potential Impact Scenario

The proposed action to increase IPP activity may result in a fuel mix that is different from the one assumed in the no-action scenario. Making a defensible prediction of the future fuel mix is difficult, using available data. Consequently, a worst-case (maximum impact) scenario, in which the proposed action would favor conventional coal-fired power generation, is assumed in defining the MPI scenario.

Not all future non-coal capacities listed in Table 1 can be easily shifted to coal combustion. Nuclear plants generally are not switched to coal firing operations because their construction is almost complete and such a switch would carry severe economic penalties. Geothermal capacity is a generally renewable resource that can be favored for electrical-power generation; it was assumed to be too price-competitive to be deleted in favor of coal firing. In the non-coal categories in Table 1 (gas, oil, hydro, and others), part of the capacity is already under construction and part is committed to serving peak and intermediate loads, each of which generally would not be available for shifting to coal-fired technologies. In addition, it is assumed that units not yet under construction could not be brought on-line as coal-fired units prior to 1993. Thus, capacity not yet under construction but required before 1993 could not be readily shifted to coal-fired technologies. Table 2 tabulates incremental capacity in terms of total capacity additions and status of units in terms of three exclusionary categories:

1. The capacity is associated with a "fixed" technology which cannot be converted to coal (i.e., nuclear-, coal-, and geothermal-based capacity);
2. The capacity is being constructed or will be needed before 1993;
3. The capacity is associated with peaking or intermediate power-production modes.

A summary of these considerations and the remaining capacity that is available for conversion to coal firing and might be affected by the rulemakings is shown in Table 3. Nine states show incremental capacities (6588 MW) which could be made available for coal firing. Of this, 95% (6280 MW) is associated with five states (California, 1194 MW; New York, 1700 MW; Oregon, 794 MW; and Texas, 1300 MW). The bulk of all impacts of the proposed action would occur in association with the capacities allocated to these states. The remaining 5% of the total conversion capacity would be so dispersed that it would result in insignificant impacts and is not considered further. With respect to California, the regulatory environment discourages new coal-fired units; for analytical purposes, we assume that the units needed to meet California's capacity would be constructed in the adjacent state of Nevada. Potential environmental impacts in these five states are evaluated in Sect. 3, using the MPI scenario.

Table 2. Projected U.S. generating capacity additions (MW) for the period 1987-1996 by state and fuel technology and capacity available for conversion to coal

State	Total future capacity addition	Nuclear, coal, and geothermal capacities	Capacity under construction or needed before 1993	Peak and intermediate loads	Capacity available for conversion to coal
Ala.	4,201	3,881	220	100	0
Alaska	193		128	65	0
Ariz.	2,480	2,330	7	48	100
Ark.	17		17		0
Calif.	7,024	974		4,856	1,194
Colo.	1,291	1,088	146		0
Conn.	13		13		0
Fla.	3,925	1,515	103	2,307	0
Ga.	4,161	3,783	300		78
Idaho	177		171	6	0
Ill.	4,250	4,250			0
Ind.	1,540	1,300		240	0
Iowa	50			50	0
Ky.	1,095	1,095			0
La.	540	540			0
Mass.	262		24	238	0
Md.	838	690		148	0
Me.	52			52	0
Mich.	2,506	1,093	1,413		0
Minn.	863	851	12		0
Miss.	250	250			0
Mo.	1,254	955		299	0
Nev.	2,285	1,725		560	0
N.H.	1,150	1,150			0
N.J.+Pa.	6,305	2,542	3,633		130
N.M.	1,126	1,000	52	74	0
N.Y.	4,696	1,889	937	170	1,700
N.C.	1,590	1,590			0
Ohio	3,673	3,658		15	0
Okla.	570	300		270	0
Oreg.	838		66	26	794[a]
R.I.	420			420	0
S.C.	1,580		1,000	580	0
Tenn.	4,764	4,764			0
Tex.	14,300	10,115	2,885		1,300
Utah	1,302	1,265	11	26	0
Vt.	221		11	210	0
Va.	1,483		6	185	1,292
Wash.	110		110		0
W.Va.	88	59	29		0
Wis.	148	60	54	34	0
Wyo.	21		21		0

[a]Replaces U.S. Army Corps of Engineers hydro in 1993-1994.

Table 3. Summary of projected U.S. electric generating capacity available for conversion to coal (1987-1996)

State	Future capacity additions (MW)	Nuclear, coal, and geothermal (MW)	Other deletions[a] (MW)	Capacity available for coal firing (MW)
Ariz.	2,485	2,330	55	100[b]
Calif.	7,024	974	4,856	1,194[c]
Ga.	4,161	3,783	300	78[d]
N.J.+Pa.	6,315	2,542	3,633	130
N.Y.	4,696	1,889	1,107	1,700[e]
Oreg.	838		44	794[f]
Tex.	14,300	10,115	2,885	1,300
Va.	1,483		191	1,292
	Total			6,588

[a]Except for California, includes (a) units under construction or approved for construction, (b) oil/gas fired internal combustion or gas turbine peaking units and gas turbine/combined cycle intermediate load units, (c) units scheduled for service before coal-fired units could be put into service in 1992 or 1993, (d) other small units, such as solar, wind, wood-fired, refuse-fired, etc., that satisfy national policy initiative to develop reusable resources and recycle wastes.

[b]The 100 MW consists of two 50-MW water-driven turbines to be added in 1994 to the existing capacity at the Theodore Roosevelt Dam of the Salt River Project Agricultural Improvement and Power District.

[c]For California, includes all projected capacity additions after 1992 except geothermal.

[d]The 78 MW consists of the addition by Georgia Power Company of two 39-MW hydroelectric turbines to existing facilities at Goat Rock Dam on the Chattahoochee River about 15 miles north of Columbus, Georgia.

[e]Includes 450 MW of hydroelectric power proposed for the Moses Niagara Station in 1995 and 1000 MW of pumped storage for 1996.

[f]The capacity available for coal firing consists of 724 MW of multi-unit hydroelectric additions in 1993 and 1994 by the U.S. Army Corps of Engineers to existing facilities (980 MW) at McNary Dam on the Columbia River near Umatilla, Oregon, plus 70 MW at several scattered hydroelectric facilities.

2.2.3 Qualifying Facility Fuel Mix Scenario

The impact assessment described in Sects. 3.1 and 3.2 is based on a scenario in which all capacities reasonably available to IPPs during the next ten years will be fulfilled using coal-fired power plants. In reality, some fuel mixes will arise when IPPs are developed, and the fuel type will not necessarily be 100% coal. Quantifying that future fuel mix is difficult with available data, however, because such IPPs currently do not exist. Rather, they are "hidden" in the QF categories (most likely as industrial cogenerators) of entrepreneurs' corporate plans that are not well-publicized and in other categories of power producers (such as existing utilities).

To approximate the fuel mix that could arise from the capacity available to IPPs, the QFs filed with FERC through December 31, 1986, were examined. Assumably, the fuel mix of any IPPs developed after the rule is initiated will parallel the fuel mix of recently qualifying facilities. Two principal weaknesses associated with this approach are (1) the FERC data base reflects QF filings only, and thus does not present a completely accurate picture of the "real world" (i.e., some QF filings are never built), and (2) the market forces and other factors that influence the fuel mix of QFs may not have the same effect on non-QF IPPs. These data reflect a generating capacity of about 42 GW, which is about 6% of the 1986 summer, installed generating capacity for the United States. Given these caveats, the QF data base is used to approximate the future IPP fuel mix.

Table 4 summarizes the fuel-mix data from the QF filings. For states for which data are available, coal percentages range from 0 to 37%, an average of about 17%, which is considerably less than the 100% level assumed in the scenario. Note that the figure for Pennsylvania is much higher than the 21% shown, in that the bulk of the "Other" category consists of coal waste from anthracite coal mining. In terms of considering total impacts from mining and power-plant operations, the numbers listed above are of principal interest. If coal waste is added to the coal category, it will increase impacts from coal combustion but not from coal mining (since the fuel is waste from mining coal for other users). Furthermore, natural gas, which is a relatively clean fuel in terms of mining and combustion, dominates the fuel mix in all of the key states except Pennsylvania.

2.3 UNCERTAINTIES

A principal uncertainty associated with the magnitude of potential impacts from the rules is the future electric generating capacity available to be converted to coal.

Two principal factors contribute to the uncertainty associated with predictors of future electric-generating capacity. First, acid rain legislation, if passed into law, could force the early retirement of as many as 30 GW of existing generating capacities, thus providing additional capacities (MW) to be affected by the IPP's (NERC 1987). Second, EIA projects that from 1996 to 2000 provide an additional 57 GW of generating capacity will be needed beyond that identified by the utilities (and used as a basis for this report). This will provide further opportunities for IPPs to affect the fuel mix of electric-power generation in the United States.

Table 4. Qualifying Facility (QF) filings fuel mix[a]

State	QF fuel mix (percent)				
	Coal	Oil	Gas	Hydro	Other
Pennsylvania	21	0	4	3	72[b]
New Jersey	8	1	71	1	19[c]
Maryland	0	18	62	3	17
New York	37	2	24	24	13

[a]Based on all QFs filed with the Federal Energy Regulatory Commission through December 31, 1986.

[b]About 52% of the "Other" category consists of anthracite-coal waste from mining operations. This would raise the coal percentage to about 73%.

[c]About 9% of the "Other" category is coal waste, which would raise the coal percentage to about 17%.

3. POTENTIAL ENVIRONMENTAL IMPACTS

The potential environmental impacts described in this section are based on the Maximum Potential Impact Scenerio developed in Sect. 2.2.2, as compared with the No Action Scenerio developed in Sect. 2.2.1. If the actual fuel mix change induced by the rules does not represent a shift to coal, and instead approximates the QF Fuel Mix Scenerio described in Sect. 2.2.3, then potential impacts would be less. If the QF-filings fuel mix is assumed to be representative of future IPPs, then the IPPS fuel mixes are likely to consist of about 20% coal. Impacts described in Sects. 3.1 and 3.2 would be about 20% of the levels predicted under the all-coal scenario. If Pennsylvania coal waste is considered, then impacts from coal combustion in that state would be about 75% of the values predicted in the all-coal industry.

3.1 COAL MINING

The quantity and distribution of additional coal production are based on the potential increase in coal-fired generation capacity and the current distribution of coal supplies by state. For each state in which additional coal-fired capacity is possible, recent data (gathered during the first six months of 1987) were used to find the current rate of coal consumption in tons of coal per GWh electric. The Oregon calculation was based on data for 1985, the last year in which significant quantities of coal were burned in Oregon for electric-power generation. These data were used to project annual coal supplies needed to fuel the new capacity, assuming a 70% capacity factor. Table 5 summarizes this information. In order to allocate coal-mining increases among source regions (shown in Fig. 2), coal sources for the additional coal-fired capacity in a given state are assumed not to change.

Table 5. Estimated new coal requirements

State	Coal consumption (tons/GWh)	New generating capacity (MW)	New coal requirement (1,000 short tons/year)
Nevada*	485	1194	3551
New York	406	1700	4232
Oregon	706	794	3438
Texas	735	1300	5859
Virginia	409	1292	3240

*Presented as a surrogate for California because electric power is not generated by direct coal combustion in California; however, coal-generated power is imported.

Assumes: (a) 70% capacity factor.
(b) Same tons coal/GWh as in first 6 months of 1987.
(c) Same source of coal shipments (by fractional distribution) as in the first 6 months of 1987.

This information is summarized in Table 6. Appendix A contains more details on developing the coal-supply scenarios.

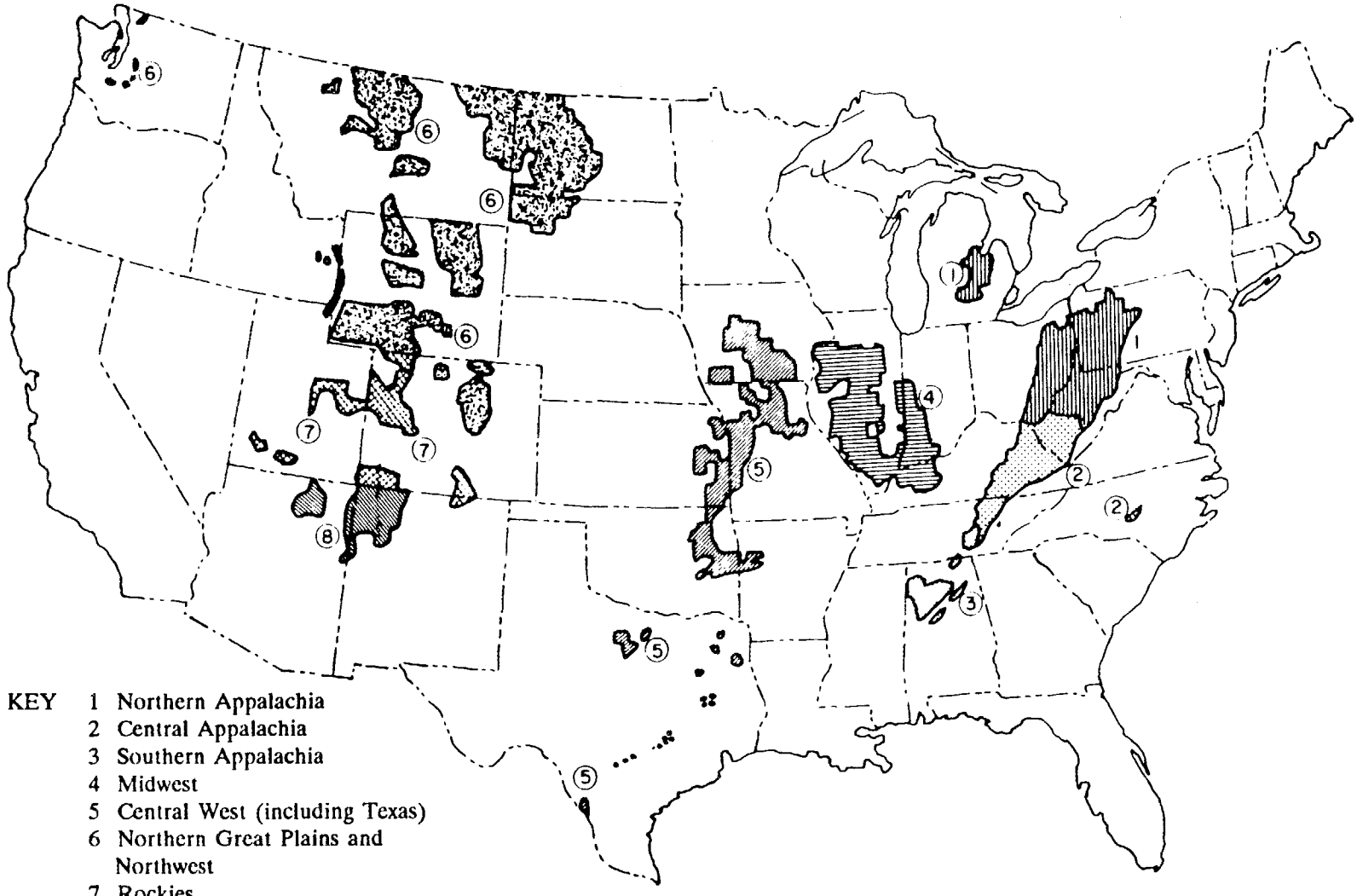

Fig. 2. Map of conterminous United States showing coal supply regions (by pattern) used in fuel-conversion analysis (Supply Regions 1 through 8).

Table 6. Coal supplied by source region to demand state for new capacity (1987-1996)

To (state)	From (region[a])	Fraction[b]	New quantity/year (1000 short ton)
Virginia	1	1.3	42
	2	98.7	3198
New York	1	94.6	4008
	2	5.4	229
Nevada	6	3.6	124
	7	30.9	1097
	8	65.5	2329
Texas	5	60.9	3521
	6	37.8	2262
	7	1.3	70
Oregon	6	100.0	3438

[a]1 Northern Appalachia
2 Central Appalachia
3 Southern Appalachia
4 Midwest
5 Central West including Texas
6 Eastern Northern Great Plains
Western Northern Great Plains
Northwest
7 Rockies
8 Southwest
(See Fig. 2. for map of regions)

[b]Percent of coal used by demand state which comes from supply regions.

Source: Federal Energy Administration, *Project Independence Evaluation System Documentation*, Vol. XII, U.S. Federal Energy Administration, Washington, D.C., 1976.

3.1.1 Water Use

Hydrologic-data-collection units described by the U.S. Water Resources Council (WRC 1978a) were matched with the coal supply regions and coal demand regions as much as possible. In most cases, the matchings were approximate, such that the area for the hydrologic data units correspond to less than the total state area. For the purpose of evaluating water use, projected 1985 water-withdrawal and water-consumption levels (millions of gallons of freshwater per day) (WRC 1978a) were tabulated for each region. Water withdrawal is defined as "water taken from a surface- or ground-water source for off-stream use," and water consumption is defined as that "portion of surface- or ground-water withdrawn for off-stream uses that is lost by evaporation or by incorporation into a manufactured product" (WRC 1978a). In-stream flow approximations (IFAs) for 1975 and projected values for 1985, expressed as millions of gallons per year (MGY), were also tabulated based on data published in WRC (1978a) for each region of interest. IFA is "an estimate of the monthly flow sufficient to support aquatic life and outdoor recreation; estimated at the outflow point" (WRC 1978a).

Hydrologic data for coal-supply regions 1 and 2 were grouped into a single region (east), as were coal-supply regions 5, 6, 7, and 8 (west). Coal-supply regions 3 and 4 are not considered here because the increase in water consumption due to mining was negligible (Table 6). Eastern and western surface mining uses 7.7×10^{-5} and 5.1×10^{-5} acre-ft water/ton coal mined, respectively (DOE undated). Underground mining in the East uses 2.0×10^{-4} acre-ft water/ton coal mined.

East-The calculated increase in water consumption due to mining from the proposed action is about 675 MGY. This compares with estimated water-withdrawal and water-consumption levels of 9×10^6 and 1×10^6 MGY, respectively, for this region. Projected consumption of water due to increased mining in this region is <1.0% of 1985 water-withdrawal and consumption levels. The calculated increase in water consumption was also <0.1% of the IFA (100×10^6 MGY).

West-The calculated increase in water consumption owing to mining was about 210 MGY. This compares with estimated water-withdrawal and water-consumption levels of $>20 \times 10^6$ and $>8 \times 10^6$ MGY, respectively, for this region. Projected water consumption because of increased mining in this region is <1% of 1985 water-withdrawal and -consumption levels and <0.1% of the IFA (365×10^6 MGY).

This preliminary analysis showed that the increase in water consumption levels by mining in the eastern and western United States would be a small percentage of projected levels of water withdrawal and water consumption due to other uses. It seems that the small increase in water use owing to mining, estimated from the available data, can be accommodated by these coal-supply regions without major regional environmental impacts. However, some western hydrologic data units derived from the Missouri Region (Coal Supply Region 6, Fig. 2) demonstrate surplus streamflows (the streamflow remaining after all off-stream and in-stream uses have been met) for 1985 that are negative, which indicates that all off-stream and in-stream uses currently exceed total streamflow (WRC 1978a). In one unit of the Missouri Region, the assessed streamflow depletion is projected to be >90% by the year 2000. Under such

conditions, streamflow is considered to be the minimum flow to sustain "short-term survival habitat" for aquatic life (Tennant 1976; WRC 1978b) and local adverse effects on aquatic life would be expected.

3.1.2 Water Quality

Data are available to evaluate the impacts of increased coal mining on water quality and aquatic ecology. Possible impacts to water quality from coal mining drainage, coal washing, and sedimentation caused by mining operations are summarized in Tables 7 and 8 (DOE 1981a). The Northern and Central Appalachian coal-supply regions (Fig. 2) have acidic drainage that can harm aquatic ecosystems by changing pH levels and causing chemical flocculation. Steep topographical features and abundant rainfall contribute to run-off problems in these regions. The mid-Atlantic and Appalachian regions are severely affected by drainage from abandoned and inactive coal mines. The U.S. Environmental Protection Agency's (EPA's) Region 3 (Pennsylvania, Maryland, Delaware, Virginia, West Virginia, and the District of Columbia) reports 49% of its streams--more than 3000 stream miles--suffer severe water-quality problems caused by acidic mine drainage (EPA 1984a). Separating the impacts of current coal mining from those of abandoned mines can be difficult because of continued discharges from abandoned mines. Although the Northern Appalachian Region would experience only a 1.7% increase in coal mining, it could experience the largest increase in polluted drainage--3097 million gallons (MG) of acidic drainage from mines and 69 MG of run-off from coal-pile refuse (Table 7).

Coal mining would increase in the Rocky Mountain (1.3%) and Southwest (2.6%) coal-supply regions. However, because of the topographical features and mining methods, these regions experience fewer problems with polluted drainage than the eastern mining regions. Polluted drainage increased moderately in the Central West and Gulf coal-supply regions; drainage in these regions is 20 to 50% acidic. Mine drainage amounts to 930 MG in the Central West and 802 MG in the Gulf Region; coal-pile run-off amounts to 24 and 47 MG, respectively. The smallest projected increases in polluted drainage from coal mining are 322 MG in the Southwest Region and 111 MG in the Rocky Mountains. Polluted water could also drain off coal-refuse piles--5 MG in the Southwest and 3 MG in the Rocky Mountains. These regions are characterized by alkaline drainage. Their topographical features, soils, and rainfall regimes create fewer erosion and run-off problems than occur in the Appalachian mining region. Abandoned coal mines do not cause significant concerns in the West, where noncoal mining is more abundant (EPA 1984a).

Potential increases in sediment loads to streams as the result of soil disturbances associated with mining can be calculated based on total acres mined in 1995 (Table 8). Sediment loads would potentially increase most in the Appalachian regions--approximately 6,100 and 13,300 short tons/year. Sediment loads in the Central West would increase by 4000 short tons/year. Sediment loads in the Southwest and Rocky Mountain regions would potentially increase by approximately 900 and 800 short tons/year, respectively. Erosion from haul roads is also a significant source of sediment at both active and abandoned mining sites, particularly in steeply sloped areas. The sediment loads calculated do not include potential erosion from haul roads. In Kentucky, erosion from abandoned coal roads, which average 65-feet wide, has been measured at between 2000 and 4000 tons per mile per year, depending on soil type (EPA 1984a).

Table 7. Potential annual increase in polluted drainage from coal mines and refuse-pile runoff (MGY)

Supply region	Polluted coal-mine drainage	Coal refuse-pile runoff
1	3097	69
2	90	18
3	0	0
4	0	0
5	930	24
6	802	47
7	111	3
8	322	5
Total	5352	166

Table 8. Potential increases in annual sediment loads[a] (short tons/year) from proposed rules

Supply region	Sediment load (short tons/year)
1	6,097
2	13,311
3	0
4	0
5	4,010
6	437
7	796
8	904
Total	25,555

[a]Does not include increased sediment loads from haul roads.

Although active mine sites may cause water-quality problems, these discharges are point-source problems and are regulated under State and Federal National Pollutant Discharge Elimination System (NPDES) permits. In addition, the Surface Mining Control and Reclamation Act (SMCRA) of 1977 states that run-off from active coal mines must be collected in sediment ponds and treated to meet point-source discharge requirements. Increases in polluted drainage and sediment discharges are proportional to increases in the amount of coal mined: 1.7% in the Northern Appalachian Region, 1.3% in the Rocky Mountain Region, and 2.6% in the Southwest Region. However, increases in pollution will be less than these figures because of water-quality regulations. Regulation and mitigation of water-quality impacts from mining are not 100% effective (EPA 1984). One could assume an average success rate of 50% in a worst-case situation. This success rate may increase during the projected 10-year period and will probably vary from region to region. Even though coal mining in a given region might increase under the rulemaking, the new regulatory requirements and improvements in reclamation techniques should counterbalance negative effects on aquatic systems. However, significant adverse impacts could occur at local or site levels if pollution-control regulatory programs fail.

3.1.3 Land Use

Both surface- and underground-coal-mining practices can change land-use patterns, topographies, soils, and vegetation types (Christman et al. 1980). Existing land uses can be temporarily or permanently eliminated from the mining area, although reclamation operations required by recent legislation (e.g., the SMCRA of 1977, Pub. L. 95-87), are increasingly effective in restoring lands disturbed by mining.

Effects on land use are relative to the amount of coal mined, the percentage of coal mined by surface methods, and the thickness of the coal seam (Christman et al. 1980). Although underground-mining operations have fewer negative effects on soils and vegetation than do surface-mining (strip-mining) operations, subsidence of shallow excavations can greatly affect topographies. As with revegetation and other reclamation techniques, implementing control technologies (e.g., backfilling the mine with waste material or collapsing its roof) eliminates many of the dangers associated with surface subsidence.

The amount of land disturbed by incremental coal mining under the proposed action was estimated using values in Christman et al. (1980), which were adjusted upward to account for recovery efficiencies of less than 100%. The table lists values for the number of acres disturbed per ton of coal mined by surface and underground methods in each of the supply regions (Fig. 2). The values were multiplied by the proportions of coal extracted by surface and underground methods in each supply region, and the tons of coal needed from each coal-supply region by each of the coal-demand states (Table 6), to yield the number of acres disturbed in each supply region.

Incremental coal mining that would result from the rules could disturb approximately an additional 3200 acres of land annually (Table 9). This can be compared to the approximately 80,000 acres of land disturbed by mining in 1985 (DOE 1981b). Land-use impacts would occur primarily in coal-supply Regions 1 and 2 (909 and 1057 acres, respectively); such lands in the Northern- and Central-Appalachian regions are forested or used for support farming (DOE 1979). Land disturbed in Region 5 (Central West) would be primarily farm and rangeland. Lesser amounts of land would be disturbed in

Table 9. Land area disturbed annually by mining that may result from the proposed action

Supply Region	Area disturbed (acres/year)	Percent of 1995 baseline[a]
Northern Appalachia	909	1.7
Central Appalachia	1057	1.3
Southern Appalachia	0	0
Midwest	0	0
Central West (including Texas)	746	3.5
Northern Great Plains and Northwest	142	2.4
Rockies	146	2.6
Southwest	155	5.3
Total	3155	16.8

[a]*Source:* Energy Information Administration, *Annual Energy Outlook*, DOE/EIA-0383, Washington, D.C., 1987.

supply Regions 7 and 8 (about 550 and 620 acres/year respectively). Land in these southwestern areas is primarily rangeland.

Percentages of incremental-mining disturbances are slightly greater than the projected 1995 baseline for all coal-supply regions (EIA 1987a) (Table 9).

Under provisions of the SMCRA (Pub. L. 95-87), most mining-disturbed land would be returned to its original condition or better. Further, SMCRA would restrict mining on lands which exhibit low reclamation potentials.

3.2 COAL COMBUSTION

3.2.1 Water Use

The water-consumption levels attributable to coal combustion in the states of interest (Table 6) were derived from the coal requirement (tons per year) and the amount of water consumed during coal combustion (gallons of water used per ton of coal burned). Water used for coal combustion was 730 and 1015 gallons per ton of coal burned for western and eastern coal, respectively (Dvorak et al. 1978). These water consumption data, which include water lost by evaporation from cooling towers, were converted to water requirement data that are unique to coal combustion (e.g., estimates that include water needed for scrubbers and ash sluicing, and *not evaporative cooling towers*) because noncooling-water requirements are assumed to be 30% of cooling-water requirements (Dvorak et al. 1978). For comparison, hydrologic data for the states of interest were compiled from published tables (Todd 1970; WRC 1978a).

Estimated water-use requirements unique to coal combustion in Nevada, New York, Oregon, Texas, and Virginia (the demand states) were approximately 780, 1300, 750, 1280, and 1000 MGY, respectively. In all states considered, estimated water requirement is <0.2% of total surface fresh-water usage levels in each state, based on 1965 state-by-state data from the USGS (Todd 1970). From this same data base (Todd 1970), water-use requirements unique to coal combustion in Nevada, Texas, and Oregon were <1% than those unique to irrigation. In New York and Virginia, water-use requirements unique to coal combustion were approximately 15% of the estimated water-use requirements for irrigation. In each state, water use owing to coal combustion was <1% of the projected 1985 in-stream flow approximation (WRC 1978a).

On first analysis, increased water use by coal-combustion industries in the demand states would not appear to impact regional aquatic life. However, assessed surplus streamflow (that is, the streamflow remaining after all off-stream and in-stream uses have been met) is negative in some areas of Nevada and Texas (WRC 1978a). Local environmental impacts on aquatic life are dependent on the siting of coal-fired power plants.

3.2.2 Water Quality

Water quality in receiving streams could be affected by cooling-system discharges, discharges from air-pollution-control equipment, and run-off from fuel-storage and residual-waste-disposal areas of power plants. Point-source regulations enforced under the Clean Water Act's National Pollutant Discharge Elimination System (NPDES), will minimize adverse impacts on water quality from coal combustion, except in the matter of coal-pile run-off and waste disposal. The quality of water discharged from a cooling system is not

affected by the fuel burned but is dependent on the type of cooling system used (e.g., once-through systems or cooling towers). Therefore, the quality of cooling water should not be impacted more by one fuel than another. Coal burning also produces ash that requires disposal. The ash is often slurried to a holding area, from which the water is recycled, evaporated, or discharged. Because point-source discharge water is regulated by NPDES, potential discharges from such disposal areas do not have much potential to adversely affect the environment.

Coal-pile run-off is a potential problem at coal-fired plants. If this run-off is not closely monitored, then coal fines, leachate-containing organics, heavy metals, and other contaminants may enter a receptive body of water. The leachate/run-off from coal piles must be collected, and the discharge would have to be monitored under an NPDES permit, which would reduce the potential for adverse impacts.

3.2.3 Land Use

Coal combustion requires land for (1) storage of coal and (2) disposal of scrubber sludge and fly-ash wastes. Table 10 outlines the additional land that could be required if new power were generated by coal rather than gas, oil, or other technologies. Coal-storage requirements were calculated using average values for 700-MW coal-fired power plants (Dvorak et al. 1979, p. 17). The methodology presented in the Fuel Use Act (DOE 1979, Appendix L) was used to calculate the additional land that would be required on a annual basis for wet-sludge and ash disposal. This method is based on the ash and sulfur content of the coal burned and assumes no recycling of either the ash or sludge. It also assumes that the wet ash or sludge is 50% water by volume. Average ash and sulfur contents of the coal from each supply region were calculated from state values (DOE 1979) weighted by 1985 state coal production. Thus coal source (and consequently ash and sulfur content) was factored into the calculations for each demand region (see Tables 5 and 6 for coal-supply and demand estimates). To assess the long-term impact of converting to coal-generated power, it was assumed that (1) the new coal plants would last 30 years and that the wastes generated annually would be additive throughout those 30 years, and (2) the water originally present in the wet ash and sludge slurries would evaporate, and the long-term volume of ash and sludge wastes for each year of operation would be half the original wet volume [long-term volume = annual wet volume x 0.5 (drying factor) x 30 (plant life)]. Dried-out sludge or ash can be covered with soil and the area can be reclaimed so that land preempted for sludge and ash wastes can be restored for other uses.

In summary, the amount of acreage that could be preempted for the disposal of sludge and ash is viewed as insignificant, at least on a national scale, because the disposal areas can be reclaimed, and vegetation can be reestablished. In heavily populated states, such as New York or California, the land requirements for waste disposal may be significant. In these states the wastes may have to be trucked out of state to be disposed of, stored, or recycled.

3.2.4 Air Quality

Under the Clean Air Act of 1970 and its 1977 amendments, air pollution is regulated by establishing ambient-air-quality standards, source-emissions

Table 10. Land preempted for coal storage and scrubber sludge and ash disposal assuming no recycling of sludge or ash. Values are in units of acres preempted and assume that the waste is applied 10 ft deep

	Va.	Nev.*	Tex.	Oreg.	N.Y.	Total acres
Annual wet scrubber sludge	48	14	85	19	71	237
Annual wet fly ash	48	32	102	39	61	282
Long-term disposal requirements	1440	690	2805	870	1980	7785
Coal storage requirements	16	15	17	10	22	80
Area disturbed over the 30-year lifespan of the plant	1456	705	2822	880	2002	7865

*Nevada is used as a surrogate for California.

standards and control-technology requirements. Current U.S. regulatory policies and standards are discussed in Appendix C.

The air-quality impacts of additional coal-fired electric-generating capacities may be determined in part by the sizes of the generating units built. Large units would be scrutinized more closely by the public, and air-pollution-control agencies and would be regulated more strictly according to air-pollution regulations. Small units may in some cases escape emission regulations by falling below the size thresholds for permits or emission-limitation requirements.

The following sections discuss the maximum sizes of small generating units that could escape emission regulations and the projected emissions of larger units, assuming these larger units were subject to typical federal emission limitations.

3.2.4.1 Generating Capacities Subject to Emission Regulation

Based on current federal New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) regulations (see Appendix C), sources larger than certain sizes are subject to emission limitations. If small coal-fired units are not subject to the same air-pollution emission standards to which larger utility-owned generating units are, the rulemaking could adversely affect overall pollutant-emissions controls and air quality.

NSPS-Based Thresholds for Emission Regulation

For electric-utility steam-generating units and other fossil-fueled steam-generating units, the NSPS are applicable if the heat-input capacity of the unit is greater than 250 M Btu/h. For industrial, commercial, and institutional steam-generating units, the threshold for triggering NSPS is 100 M Btu/h. Assuming a conversion efficiency of 38% for coal-fired electric generating units (FWS 1978), these NSPS would be applicable to coal-fired boilers generating more than ~27.7 and 10.6 MW, respectively.

Some states regulate emission rates from sources much smaller than those regulated by the federal NSPS. Thus, the federal NSPS determine an upper limit on the size of boilers that do not have to be regulated.

PSD-Based Threshold for Emission Regulation

PSD regulations would apply to any fossil-fueled boilers or electric generating units that have more than 250 M Btu/h heat input *and* emit more than 100 tons/year of one or more Clean Air Act (CAA) pollutants (any pollutant listed in Table C.1, except for lead and ozone.) The PSD regulations also apply to any source type that emits more than 250 tons/year of any CAA pollutant. Although PSD regulations set no specific emission limits, sources subject to PSD are required to have emission limitations at least as stringent as the NSPS for each emitted pollutant subject to PSD review. The emission limit set by PSD, referred to as the "best available control technology" emission limit, is determined by EPA on a case-by-case basis, taking into account energy, environmental and economic impacts, and costs.

For most coal-fired boilers without emission controls, the CAA pollutant emitted in the greatest quantity is sulfur dioxide (SO_2). According to the EPA publication AP-42 (EPA 1984b), nitrogen oxides would be emitted in greater quantities than SO_2 only for certain types of boilers that burn very low-sulfur coal. Thus, the following discussion, regarding boiler capacities subject to emission regulations will be based on the assumption that the most critical pollutant regulated by PSD is SO_2.

If no SO_2 emissions controls for coal-fired boilers are assumed, the PSD regulations would be applied at lower heat inputs (smaller boiler sizes) than those to which NSPS are applied. This can be shown by calculating the heat input necessary to produce an SO_2 emission rate of 250 tons/year using various types of coals. The results of such calculations are shown in Table 10, which has been adapted from data presented by FWS (1978). As can be seen, the 250-tons/year limit for PSD applicability would be reached with heat inputs well below 250 M Btu/h, the NSPS limit for fossil-fueled steam generators and electric-utility-steam-generating units. NSPS also are applicable to industrial, commercial, and institutional boilers with >100 M Btu/h heat input. According to the data in Table 11, the 250-tons/year limit for PSD applicability would be reached before the NSPS limit for this source category.

Also presented in Table 11 are the approximate electric outputs that could be generated from different types of coals without exceeding the 250-tons/year limit for SO_2 emissions. These data were calculated by assuming no emission controls and a 38% energy-conversion efficiency for electric generation from coal. The maximum generating capacities in the PSD threshold range from 1.2 to 8.0 MW, and average ~4 MW.

Thus, for the proposed rule to have a maximum adverse effect on allowable pollutant-emission levels, a significant number of small, unregulated coal-fired emission sources would have to be built. On the

Table 11. Range of sulfur and heat contents in coal seams of several regions of the country and energy input and equivalent electrical power output based on the regulatory review limit of 250 tons per year SO_2[a]

Region/State	Seam	Sulfur content range (percent)	Heat content Range, Btu/lb	Energy input and output at 250 tons/year SO_2 for selected sulfur and heat contents[b]			
				Sulfur (percent)	Heat (Btu/lb)	(MMBtu/hr)	Output (MW)
Northern Appalachian							
West Virginia	Pittsburgh	0.6-14	11,400-14,800	3.0	13,500	13.2	1.5
Pennsylvania	Pittsburgh	0.7-3.3	13,040-14,340	0.7	13,500	56.5	6.3
Southern Appalachian							
Eastern Kentucky	Upper Elkhorn #3	--	--	0.9	14,200	46.2	5.1
Tennessee	Upper Elkhorn #3 (Jellico)	0.7-3.2	12,630-14,290	2.5	13,000	15.2	1.7
Virginia	Upper Banner	0.5-0.7	14,600-14,870	0.6	14,700	71.1	8.0
Alabama	Mary Lee	0.5-2.6	11,570-14,700	1.6	13,000	23.8	2.6
Eastern Interior							
Illinois	(No.5) Harrisburg-Springfield	2-5	10,000-12,700	3.3	12,000	10.6	1.2
Powder River Region							
Wyoming	Anderson & Canyon & Wyodak-Anderson	0.14-1.2	7,128-9,600	0.4	8,500	69.3	7.7
Fort Union Lignite							
North Dakota	Undefined	0.2-1.4	5,860-7,487	0.6	6,800	43.1	4.8
Gulf Coast Lignite							
Texas	Wilcox Group	--	--	0.8	7,700	36.6	4.1
Four Corners							
Arizona	Wepo	0.4-0.9	10,450-12,060	0.6	11,500	62.5	7.0
New Mexico	Navajo			0.7	9,200	42.9	4.8

[a]*Source:* Adapted from U.S. Fish and Wildlife Service, *A Biologist's Manual for the Evaluation of Impacts of Coal-Fired Power Plants on Fish, Wildlife, and Their Habitats*, FWS/OBS-78/75, Argonne National Laboratory, Argonne, Ill., 1978.
[b]Assumes no SO_2 controls and energy conversion efficiency of 38%. SO_2 emission factors from U.S. Environmental Protection Agency, *Completion of Air Pollutant Emission Factors, 3rd ed.* EPA Publication AP 42, Research Triangle Park, N.C., 1984. Dashes indicate that no range values were available.

average, such sources would need to be smaller than 4 MW to be exempted from emission regulations. In some states, emission limits are more stringent than those allowed by the NSPS or PSD regulations, and generating units would have to be much smaller than 4 MW to be exempted from emission regulations.

3.2.4.2 Projected Emissions Increases

Based on new generating capacities for coal in each of the five states analyzed (Table 3), emissions increases were estimated for SO_x (as SO_2), NO_x (as NO_2), and TSP. These emissions increases, based on coal-firing, were calculated by using NSPS most generally applied to electric-generating facilities and by assuming there are no small generating units with uncontrolled emissions. For certain types of low-sulfur coals, the percent-reduction requirements applicable under NSPS could result in lower SO_x-emission rates.

The projected emissions increases for each state are shown in Table 12, along with the estimated 1986 statewide emissions and the percentage increases for each pollutant. The percentage increases are negligible for TSP in all cases. Projected SO_x- and NO_x-emission increases are relatively minor in Virginia, are moderate in New York and New Jersey, and are substantial in Nevada. Although the projected NO_x-emission increases in Nevada are only moderately greater than those in New Jersey and New York, they represent much larger percentage increases. Because Nevada is a predominantly rural state with few industrial and automobile emissions, a given increment in NO_x emissions represents a much larger percentage increase in Nevada than in more populous states.

Nevada's coal-fired plants may not be the sole source of power to fulfill California's energy needs. Perhaps California's energy demands could be met by coal-fired plants built in Utah or in the Four Corners area, where other large coal-fired plants have been built. However, any locations in the Southwestern United States have significant potentials to degrade air quality and visibility at national parks in the region. The emissions increases projected for Nevada (or any state in this region) have the greatest potentials to adversely impact air quality.

3.2.4.3 Existing Air Quality

The existing air-quality levels relative to National Ambient Air Quality Standards (NAAQS) (see Appendix C) are discussed below for each of the five states analyzed. Only those pollutants (SO_2, NO_2 and TSP) expected to be emitted in significant quantities by coal-mining and coal-combustion sources are addressed. This discussion is based on data monitored in 1986. Although the TSP NAAQS were replaced by size-specific-particulate-matter NAAQS by July 31, 1987, the discussion applies to the original TSP NAAQS, which were effective for the period during which the data were monitored.

Figures 3, 4, 5, and 6 show areas of Oregon, New York, Nevada, and Texas (respectively) whose air quality standards did not meet NAAQS for TSP as of November 1986. Figure 7 shows the area of east central Nevada whose air quality did not meet NAAQS for SO_2 at that time.

Nevada. The NAAQS for NO_2 was met throughout Nevada during 1986. The air quality in areas surrounding Las Vegas and Reno did not meet the NAAQS for TSP. The air quality in an area in east-central Nevada did not meet the NAAQS for SO_2.

Table 12. Projected emissions increases from incremental increase in coal-fired MW for selected states[a]

State	MW	Projected emissions increases (10^3 tons/year)			1986 estimated emissions (10^3 tons/year)[b]			% increase		
		SO_x	NO_x	TSP	SO_x	NO_x	TSP	SO_x	NO_x	TSP
Nevada[c]	1194	28	28	2	303	122	787	9	23	<1
New York	1700	71	71	3	932	725	607	8	10	<1
Virginia	1292	31	31	2	321	390	400	10	8	<1
Oregon	794	19	19	1	60	227	1568	32	8	<1
Texas	1300	31	31	2	1300	3566	4965	2	<1	<1

[a]All emission computations were performed assuming the following new source performance standards: SO_2, 0.6 lb/MMBtu; NO_2, 0.6 lb/MMBtu; TSP, 0.03 lb/MMBtu.

[b]1986 emissions computed by adjusting 1981 state inventory by the following factors computed from U.S. Environmental Protection Agency, *National Air Quality and Emissions Trends Report, 1986*, EPA-450/4-88-001, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., 1988: TSP, 15%; SO_x, 10%; NO_x, 5%.

[c]Coal-fired power plants are assumed to be sited in Nevada to supply California's power needs.

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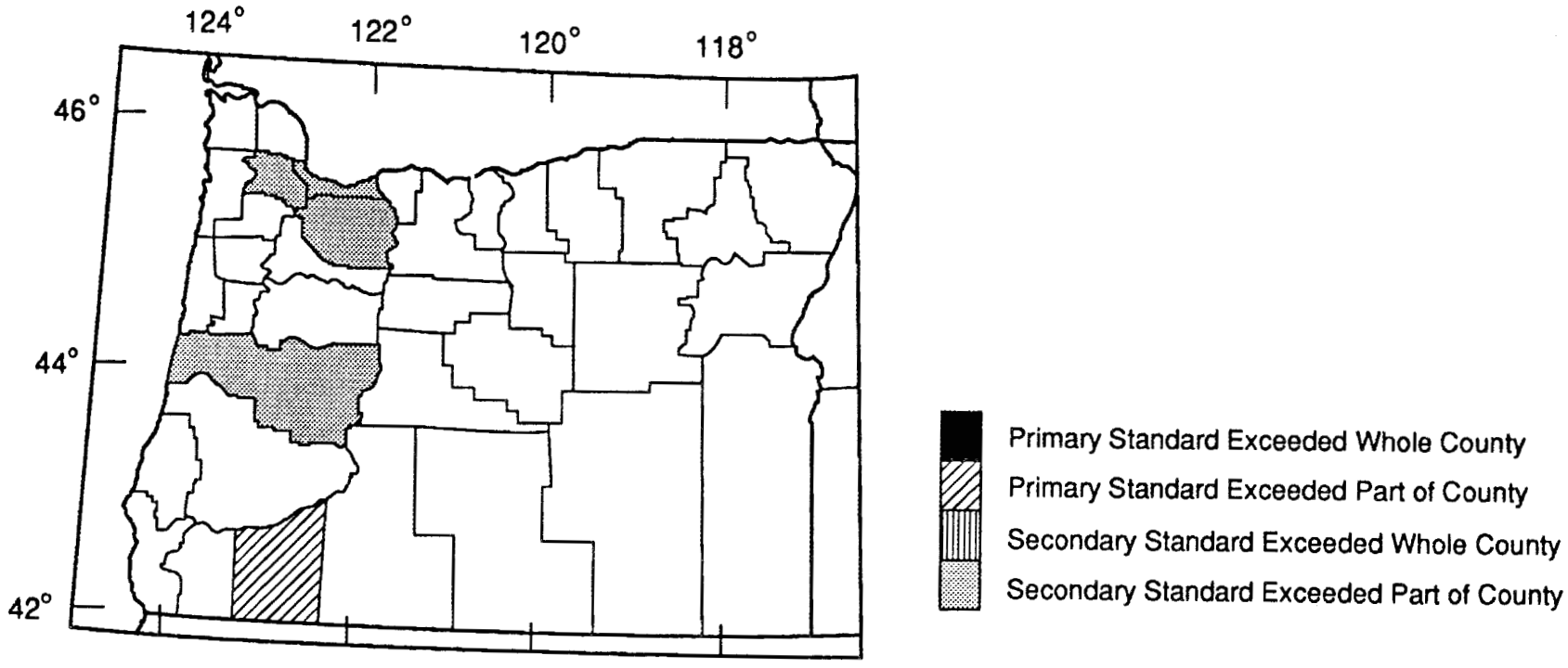

Fig. 3. Attainment status of counties in Oregon, as of November 1986, for TSP.

Source: U.S. Environmental Protection Agency, *Summary of Attainment Status of Counties in the United States*, Research Triangle Park, N.C., 1986.

ORNL-DWG 90M-7347

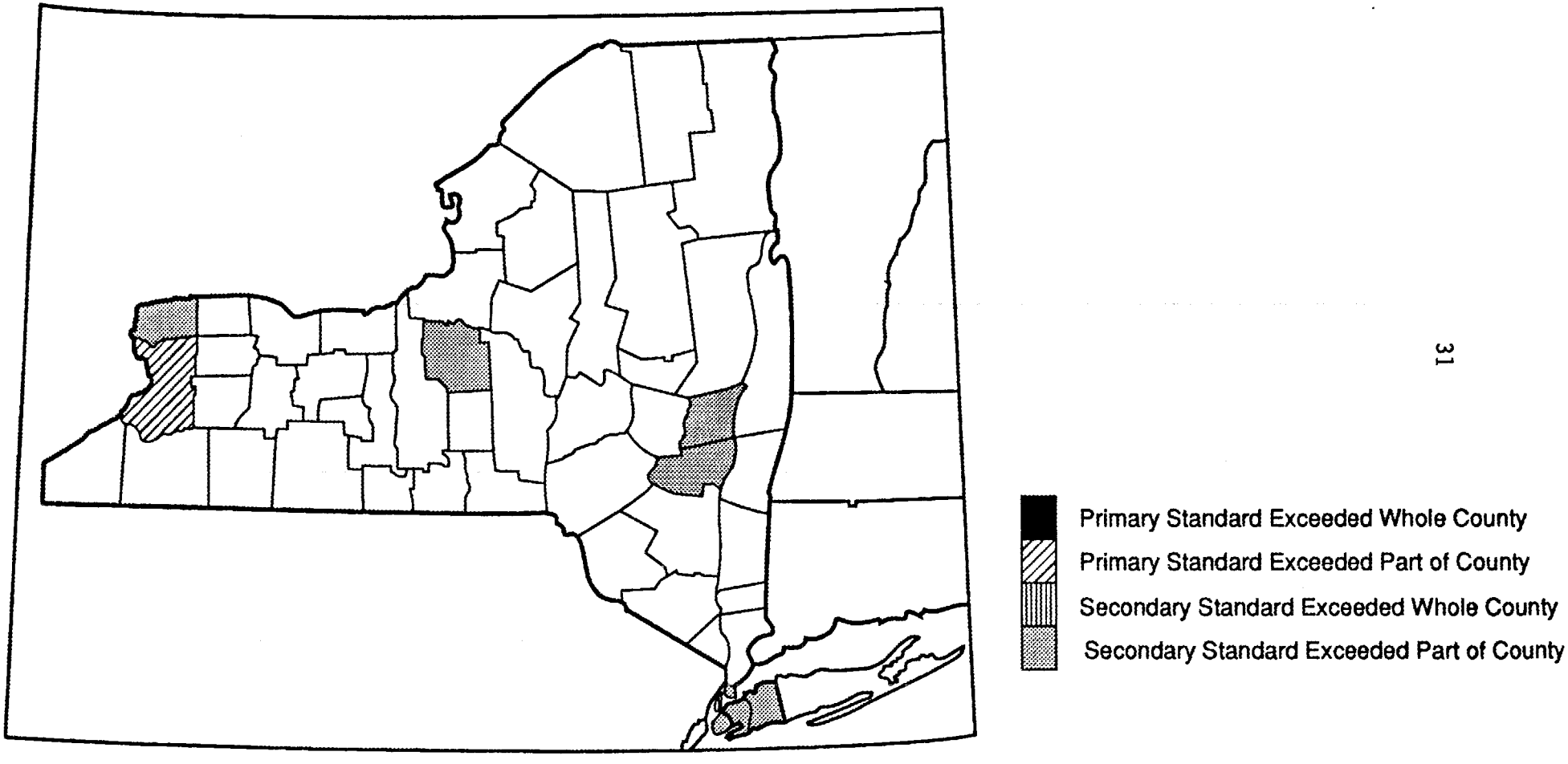

Fig. 4. Attainment status of counties in New York, as of November 1986, for TSP.

Source: U.S. Environmental Protection Agency, *Summary of Attainment Status of Counties in the United States*, Research Triangle Park, N.C., 1986.

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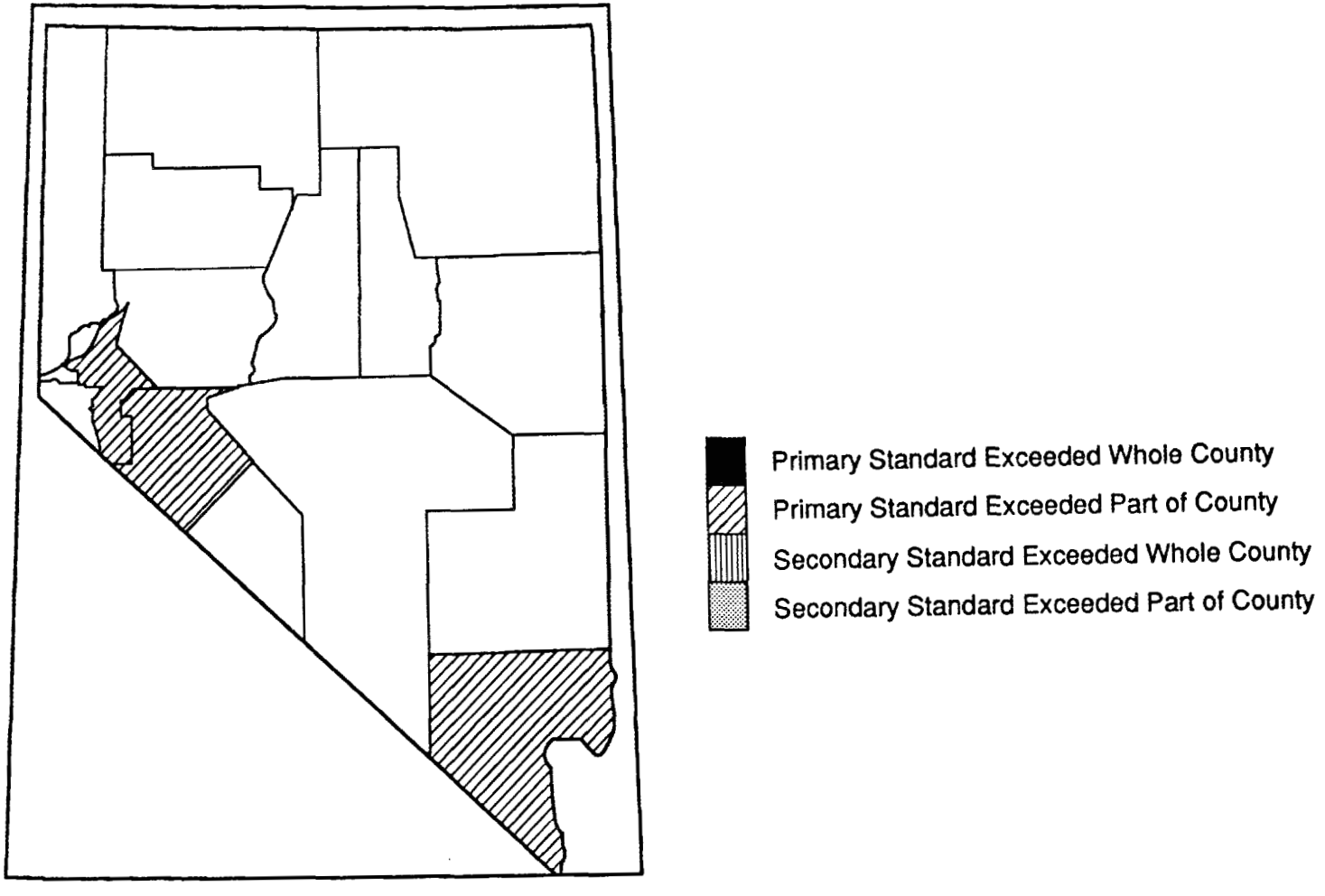

Fig. 5. Attainment status of counties in Nevada, as of November 1986, for TSP.

Source: U.S. Environmental Protection Agency, *Summary of Attainment Status of Counties in the United States*, Research Triangle Park, N.C., 1986.

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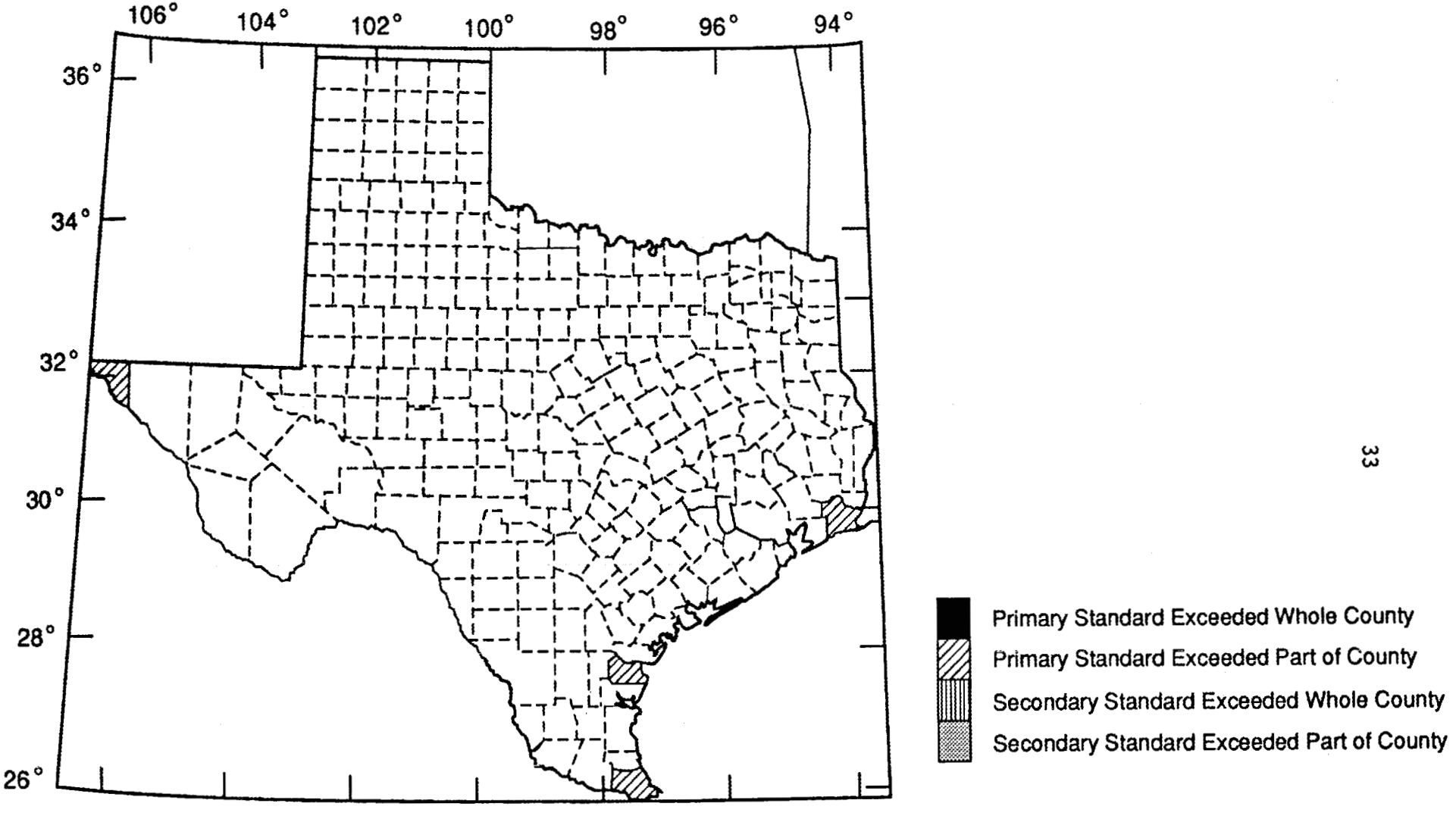

Fig. 6. Attainment status of counties in Texas, as of November 1986, for TSP.

Source: U.S. Environmental Protection Agency, *Summary of Attainment Status of Counties in the United States*, Research Triangle Park, N.C., 1986.

ORNL-DWG 90M-7346

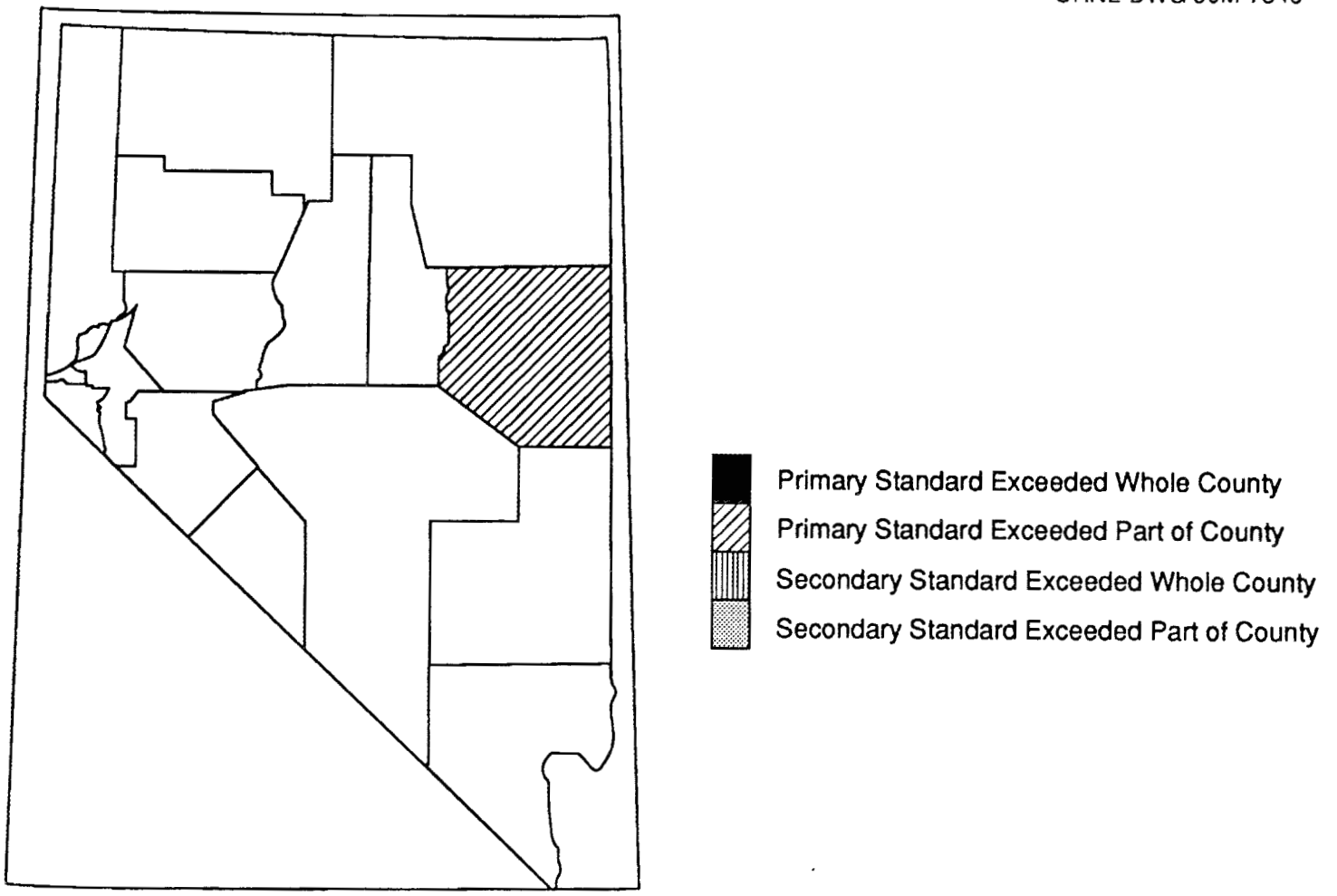

Fig. 7. Attainment status of counties in Nevada, as of November 1986, for SO_2.

Source: U.S. Environmental Protection Agency, *Summary of Attainment Status of Counties in the United States*, Research Triangle Park, N.C., 1986.

New York. Ambient-air-quality data showed that New York was in compliance with the NAAQS for SO_2 and NO_2 during 1986. Concentrations of these pollutants throughout most of the state were well below NAAQS. The air quality in several counties did not meet NAAQS for TSP.

Oregon. The NAAQS for SO_2 and NO_2 were attained throughout Oregon during 1986. Throughout most of the state, concentrations of these pollutants were well below the standards. There were three areas of nonattainment for TSP: Portland, Medford, and Eugene/Springfield.

Texas. During 1986, the ambient-air quality in most areas of Texas was appreciably better than the NAAQS. The air quality in the entire state met the NAAQS for SO_2 and NO_2. The air quality in four areas did not meet the NAAQS for TSP: Houston, Corpus Christi, Brownsville, and El Paso.

Virginia. During 1986, the ambient-air quality in most areas of Virginia was considerably better than the NAAQS. The entire state was in compliance with standards for SO_2 and NO_2. The TSP standard was met throughout the state except for a small, isolated site in Roanoke.

3.2.5 CO_2 Emissions/Climate Change

Anything that increases the annual rate of coal burning will increase the rate of discharge of CO_2 to the atmosphere and will increase the potential for global-climate changes. Of the conventional electricity-generating processes, coal-fired boilers have the highest rate of CO_2 discharges. Assuming that fuel can be converted to electricity at 38% thermal efficiency in a modern generating plant, the values presented by Marland (1982) can be used to calculate kg of carbon discharged as CO_2 per 10^9 J of electricity generated. This can be translated to kg C per year per MW of generating capacity assuming an annual capacity factor for generating plants. The table below shows these factors for three basic fuels. The factor shown for bituminous coal does not differ significantly for other types of coal.

	CO_2 emission rate kg C / 10^9 J electricity	kg C per year per MW capacity at 70% capacity factor
natural gas	36.3	0.80×10^6
liquid fuels	51.8	1.14×10^6
bituminous coal	62.9	1.39×10^6

If 6588 MW of gas-fired capacity were converted to an equivalent output of coal-fired capacity, the total increase in CO_2 emissions to the atmosphere would be 3.9×10^9 kg C $year^{-1}$. Table 13 presents the distribution of the estimated increase in CO_2 emissions for each of the states of interest (which represent 95% of the total 6588 MW). Comparing the total estimated change in CO_2 emissions from the proposed rules (3.7×10^9 kg C year) with the U.S. annual CO_2 emissions from fossil fuel combustion (1135×10^9 kg C year in 1982) (Marland 1988) indicates a small potential (less than 0.5%) to increase CO_2 emissions and a correspondingly small potential to contribute to CO_2-induced climate change.

Table 13. Estimated increase in annual CO_2 emissions from conversion of natural gas electric generating plants to coal in states of interest

State	Extra coal capacity (MW)	Extra carbon under all coal (kg/yr)[a, b]
Nevada	1194	0.70×10^9
New York	1700	1.0×10^9
Oregon	794	0.47×10^9
Texas	1300	0.77×10^9
Virginia	1292	0.76×10^9
		3.7×10^9 kg C/year

[a]Based on 1.39×10^6 kg C/MW of coal power and 0.80×10^6 kg C/MW of gas power.

[b]Assumes all capacity shown is converted from gas to coal.

4. FINDINGS AND CONCLUSIONS

For impact assessment purposes, it was assumed that all of the capacity affected by the rules would be converted to a coal-fired technology. Coal was selected because it has the greatest potential for consistently causing adverse regional environmental impacts for mining and power-plant operations when compared with other technologies (e.g., oil, gas, refuse, industrial waste, etc). Five states (California, New York, Oregon, Texas, and Virginia) had more than 95% of the capacity potentially affected by the proposed rules. Based upon utility projections of future electric generating capacity and assumptions in Sect. 2, the proposed rules have the potential to affect about 8% of the electric generating capacity (88,000 MW) planned to come on line by 1996.

An analysis of the environmental impacts the scenario might cause uncovered general environmental concerns:

- Coal mining--The largest increases in coal mining would occur in the Rocky Mountain (1.3%) and the Southwest (2.6%) coal-supply regions. However, acidic mine drainage and erosion problems should be minimized by topographic features, soils, and rainfall regimes in the regions. In the Appalachian Mountains, where a 1.7% increase in coal mining is projected, impacts from acidic mine drainage are more important.
- Waste from coal combustion--Scrubber sludge, fly ash, and bottom ash require acreage for disposal. In heavily populated states, such as New York, the land requirements for waste disposal may be significant and may necessitate off-site disposal.
- Power-plant operations in California (1194 MW)--The absence of existing or planned coal-fired utility power plants in California indicates that the rulemakings will not likely result in the development of coal-fired generation to meet projected generating requirements in the state. Consequently, the capacity (MW) of new-unit additions assumably would be met by coal combustion in Nevada. Recent (1986) air-quality attainment data for Nevada indicate that the NAAQS are violated by SO_2 emissions in part of a county and by TSP in Reno and Las Vegas areas. Emission increases from the projected addition of coal capacity (MW) would result in emissions of SO_x and NO_x that are 9% and 23% of 1986 estimated emissions for Nevada, respectively. Although these emissions could probably be permitted without further violations of NAAQS, visibility degradation in the Grand Canyon and other western national parks and monuments has been traced in part to emissions from fuel combustion in Nevada. Water-use impacts by power-plant operations may also be significant in Nevada, although, on a statewide basis, the projected increase in water consumption by coal-power plant operations is less than 0.2% of estimated 1985 total water-consumption levels for the state. Nevada has specific environmental-control and preproject, environmental-assessment regulations for IPPs (see Appendix B).
- Power-plant operations in New York (1700 MW)--The coal scenario would increase emissions of SO_x and NO_x by 8% and 10%, respectively, more than 1986 estimated statewide totals. Although

some areas of New York violated TSP NAAQS in 1986, power-plant emissions are not expected to affect TSP levels significantly. New York has a preproject, environmental-review law that could apply to IPPs, and a power-plant review law that contains partial exemptions from requirements for power plants in certain size categories and thus could result in less-extensive reviews for some IPPs.

- Power-plant operations in Oregon (794 MW)--The coal scenario would increase emissions of SO_x, NO_x, and TSP by 32%, 8%, and <1%, respectively, more than estimated statewide 1986 totals.
- Power-plant operations in Texas (1300 MW)--The coal scenario would increase emissions of SO_x, NO_x, and TSP by 2%, <1%, and <1% more than estimated statewide 1986 totals.
- Power-plant operations in Virginia (1292 MW)--The coal scenario would increase emissions of SO_x, NO_x and TSP by 10%, 8%, and <1% more than 1986 estimated statewide totals. These emissions are not likely to exacerbate air-quality problems as badly as is projected for some of the other states. Concentrations of these pollutants are well below the NAAQS for nearly all of Virginia. Virginia, however, has no comprehensive preproject, environmental-review law that would apply to IPPs.
- The increase in VCO_2 emissions from the proposed rules would be less than 0.5% of 1982 U.S. annual CO_2 emissions from fossil-fuel combustion (assuming capacity affected is converted from natural gas to coal), which offers little potential to increase CO_2 emissions and affect CO_2-related climate changes. The environmental analysis is overly conservative because the bidding rule stipulates that maintaining or encouraging fuel diversity must be a nonprice criterion in adopting bidding. IPPs developed in the near future may mirror the fuel mix of the historical QF filings (i.e., 20% coal).

Presumably, no additional facilities will qualify [i.e., the available capacity (MW) will be supplied by coal-burning independent power producers]. This is a worst-case scenario because PURPA gives strong incentives for a generator to be a QF (e.g., guaranteed access to transmission lines, guaranteed payments from utilities for the cost of energy production, no PUHCA requirements, etc). Thus, the predicted capacity (MW) available for coal-burning IPPs will actually be less because some of them will be met with QFs that are fueled with something other than coal. The actual fuel mix of future QFs cannot be predicted with available data; however, an analysis of about 43 GW of QF filings during 1986 indicates that, historically, QFs have been about 20% coal.

Findings for the alternatives examined are as follows:

- No action--Future electric generation will be carried out using the fuel mix postulated by the utilities. Some IPPs may develop more slowly than they would under the rule. The impacts of meeting the projected need for power through 1996 are not germane to this action and are thus beyond the scope of this assessment. A NEPA review that appropriately considers cumulative impacts would not be conducted.

- Case-by-case--The rulemaking will be implemented by precedent through a case-by-case development of IPPs. If the rule is not made, fewer impacts would occur because the IPPs development would be delayed. A NEPA review that appropriately considers cumulative impacts would not be conducted.
- Policy statement--This is a nonbinding statement that has little potential to affect the electric-generating industry and has correspondingly little potential to cause environmental impacts.
- Interpretive rulemaking--This is also a nonbinding statement that has little potential to affect the electric-generating industry and has correspondingly little potential to result in environmental impacts.

Given the potential for serious water use and air quality impacts in the west from coal combustion, and the potential effects from acid coal mine drainage in the Appalachian Mountains, potential environmental impacts from the rules are not clearly insignificant. Therefore, the appropriate level of environmental review for the proposed rules under NEPA would be an EIS. This would allow a more detailed analysis of potential effects that in turn could result in the identification of mitigation measures that would reduce potential effects from the rules.

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APPENDIX A

COAL SUPPLY SCENARIOS

Table A.1. Derivation of coal consumption rates

Demand state	Net generation by coal Jan.-June 1987 (GWh)	Consumption of coal to produce electricity Jan.-June 1987 (1000 short tons)	Consumption of coal (in tons) /GWh
Nevada*	6,877[a]	3,337[b]	485
New York	9,159[a]	3,720[b]	406
Oregon	592[c]	418[d]	706
Texas	49,917[a]	36,699[b]	735
Virginia	8,917[a]	3,650[b]	409

[a]Energy Information Administration, Electric Power Monthly, DOE/EIA-0226 (June 1987).
[b]Energy Information Administration, Coal Distribution, DOE/EIA-0125 (2d Quarter 1987).
[c]Energy Information Administration, Electric Power Monthly, DOE/EIA-0226 (December 1985).
[d]Energy Information Administration, Coal Distribution, DOE/EIA-0125 (4th Quarter 1985).
*Used as a surrogate for California.

APPENDIX B

STATE ENVIRONMENTAL-REVIEW REQUIREMENTS

APPENDIX B

STATE ENVIRONMENTAL-REVIEW REQUIREMENTS

Many states have legislative policies that state that an environmental-impact assessment must be conducted before certain actions, such as constructing and operating power plants, can be taken. In some states, the environmental review of a proposed power-plant project is part of a certification process for the plant, closely parallels federal environmental-review process carried out in compliance with the National Environmental Policy Act of 1969 (NEPA), and involves the public in scoping and reviewing the impact assessment. In other states, the environmental review simply requires the applicant, who must obtain one or more pollution-control permits, to complete a questionnaire that addresses potential impacts in specific resource areas.

Information on state environmental-review requirements was obtained from literature, environmental directories, and personal communications with state-government officials and representatives. The following section summarizes review requirements in the states of interest to this project.

MID-ATLANTIC REGION

Delaware

Delaware does not have any comprehensive environmental legislation comparable to NEPA, or any power-plant-siting requirements. The Department of Natural Resources and Environmental Control oversees the protection of the environment by the permitting actions of its various divisions, such as Air and Waste Management, Water Resources, and Fish and Wildlife. The process for obtaining air-quality, water-quality, and other necessary permits is coordinated by the department's Development and Advisory Service. Because of its location on the Atlantic coast, coastal-zone management and wetlands protection are important aspects of environmental permitting actions. The process of obtaining a permit for coastal zone construction involves public notice of the action and of the status decision made by the department and a public hearing. The process of obtaining an air-quality permit also requires that a legal notice of application be published, but that a public hearing is required only upon request.

Maryland

Maryland has enacted the Maryland Environmental Policy Act of 1973; however, this act applies only to other legislation. Protection of the environment is achieved through the permitting processes regulated by the Department of Environment. Unlike Delaware, however, the state has a Public Service Commission (PSC) that dictates procedural requirements that must be followed for a power plant to receive a "certificate of public convenience and necessity." Environmental review is one of these requirements. Applicants for certification must provide an environmental report to the PSC, which then forwards the report to the state's Department of Natural Resources and Department of Environment for concurrent review by various environmental-protection agencies.

New Jersey

New Jersey has no comprehensive environmental legislation requiring a formal environmental review process, and like the other mid-Atlantic states, relies on the permitting actions of its Department of Environmental Protection to maintain the quality of the environment. New Jersey has published a Directory of State Programs for Regulating Construction that provides details on all permits, certificates, and approvals required by state regulatory agencies for new construction or substantial expansion. Review of permit applications involves legal notices of intended actions and public involvement to the extent deemed necessary from response to public notices. Development of an independent power plant would be subject to the agency requirements for individual permits which are sought and, depending on where the plant is sited, would be reviewed for potential impacts to protected areas such as the Pine Barrens and the coastal zone/wetlands.

New York

New York has a State Environmental Quality Review (SEQR) that is performed under Environmental Conservation Law, Section 8-0113, and implemented by the Department of Environmental Conservation. The SEQR requires that all agencies determine whether the actions they directly undertake, fund, or approve may have a significant effect on the environment and, if so, that they prepare or request an applicant to prepare an environmental impact statement. The SEQR is fashioned after NEPA and includes public involvement when it is perceived to be warranted. In addition to SEQR, the state has defined in Article 8 of its Public Service Law requirements for site-specific environmental reviews of power plants greater than 50 MW. Article 8 does not apply to cogeneration facilities in the 50-80 MW range. A "certificate of environmental compatibility and public need" is granted or denied based on the environmental review conducted by the Public Service Commission.

The SEQR is initiated by the applicant's completion of an environmental assessment form (EAF), from which a preliminary determination of the potential for significant impacts is made. The agency may issue a positive declaration, a negative declaration, or a conditioned negative declaration based on information received in the EAF. The positive declaration necessitates the preparation of a full-blown environmental impact statement (EIS), with the option of formal scoping and a 30-day public comment period on the draft EIS.

Pennsylvania

Pennsylvania has neither legislation applicable to the siting and operation of power plants, nor a formal environmental-review process. The various agencies of the state's Department of Environmental Resources issue permits for air quality, water quality, stream encroachment, and other potential effects on a case-by-case basis, and do not require environmental reviews to be conducted for reasons other than technical support or justification for the proposed action. Notices of applications for environmental permits are given by the state, and time is allowed for public comment.

MIDWEST

Michigan

Implementation of Michigan Executive Order 1974-4 (MEO) requires that each agency of state government conduct formal environmental assessments on all their major activities that could significantly impact the environment or human life. The MEO further requires the assessment to be evaluated by the Environmental Review Board with the aid of the Inter-Departmental Environmental Review Committee. Use of public-involvement procedures and public hearings is encouraged as part of the decision-making process, and the public must be informed and have the opportunity to be heard. An EIS is prepared when (1) the Governor requests it, (2) the director of an agency determines that it may have a significant impact as defined in the state guidelines for implementing MEO 1974-4, (3) an activity raises public concern or controversy, (4) the state Environmental Review Board requests one, or (5) the Board requests one under special actions guidelines. Development of a power plant in Michigan probably would require a state environmental review for either the permitting process for certain actions or certification by the state PSC.

SOUTH:

Alabama

Alabama has no comprehensive environmental legislation and no power-plant siting requirements. The Department of Environmental Management, which issues air-quality, water-quality, and other permits, requires, upon application, technical support or justification for the proposed action. No omnibus environmental review is conducted. A new power plant would probably have to seek permits from various state agencies, but would not likely be required to submit to a formal environmental-impact assessment process.

Florida

Florida has no comprehensive environmental legislation but does have the Florida Electric Power Plant Siting Act, which has specific environmental-review requirements that must be met prior to site certification. State agencies require that technical support and justification accompany applications for permits, as do most other states. Public meetings are held in conjunction with the application for site certification. The applicant provides the state with an environmental-impact report that is concurrently reviewed by various agencies of the Department of Environmental Regulation, including the Power Plant Division. The certification-review process concludes with administrative hearings and recommendations by the hearings officer and governor.

Georgia

Georgia has neither environmental legislation requiring an environmental review similar to the NEPA process nor power-plant siting requirements. The various environmental-protection agencies of the Department of Natural Resources (DNR) issue permits based on technical information provided by

applicants. Thirty days before issuance of a permit, the DNR advises the public of the potential action. Unless extreme controversy or important questions regarding the technical nature of the project arise, no public hearings are held. As with other states, the development of an independent power plant would require environmental review only to the extent necessary to satisfy permit-issuing agencies.

North Carolina

The North Carolina Administrative Code, Title 1, Chapter 25 of the North Carolina Environmental Policy Act, establishes procedures for compliance with the North Carolina Environmental Policy Act, Article I, Chapter 113A of the General Statutes. The procedures apply only to actions involving expenditures of public monies. State agencies may prepare either environmental assessments (EAs) or EISs, depending on the predetermined potential for significant impacts. No power-plant siting laws exist in North Carolina, but such a large-scale project probably would draw public attention, and an environmental-impact review would be beneficial.

South Carolina

South Carolina has no state environmental legislation requiring a formal environmental review and no state power-plant-siting requirements. The Department of Health and Environmental Conservation has primacy for issuing federal permits and requires technical support or justification for the proposed alternative prior to issuing permits. It was reported that several utilities have prepared EAs or EISs, although none were required, so that if questions or concerns arose, documentation would be readily available.

Texas

Texas does not have a state statute similar to NEPA. The state Public Utility Commission (PUC) factors environmental considerations into its deliberations regarding the issuance of a Certificate of Convenience and Necessity (CCN) for a proposed power plant. Facilities that qualify by FERC definition are not required to obtain a CCN. The CCN approval procedure first involves a public announcement of the Notice of Intent (NOI) for the project, followed by public hearings regarding the nature of the project. If the NOI is approved by the PUC, a more detailed application is provided by the developer, including an environmental report. A second public hearing is held at which the public may intervene. The PUC judges the environmental impacts of the project against an internal list of criteria, and considers public testimony when it decides whether or not to issue a CCN.

Virginia

The Virginia Council on the Environment (VCE) implements the requirements of the Virginia Environmental Quality Act (Va. Code 1950, Sect. 10-177 et seq.), while the State Corporation Commission regulates utilities. The VCE coordinates the review of federal NEPA documents and state-agency environmental documents. Permitting actions by state pollution-control agencies require the proposed action to have technical support that indirectly incorporates environmental considerations.

WEST

Arizona

The Arizona Corporation Commission issues a "certificate of environmental compatibility" under the Power Plant and Transmission Line Siting Act (ARS 40-360 to 40-360.13) subsequent to a review of environmental information provided by an applicant. The review is performed by an ex officio committee composed of representatives of various state environmental agencies. A public hearing is held at the beginning of the certification review. In addition to this review, one would be required to apply to individual state agencies in the Department of Health Services for various permits before building an independent power plant in Arizona.

California

The California Environmental Quality Act (CEQA) requires environmental-impact reports similar to federal EISs to be written and requires that they include mitigation measures and growth-inducing effects. The law applies to state agencies and local governments. CEQA has detailed provisions governing the preparation of impact reports and judicial reviews. The Energy Facilities Siting and Environmental Protection Division of the Energy Resources Conservation and Development Commission prepares CEQA documentation for thermal-power plants that are greater than 50 MW. Plants less than 50 MW usually are scrutinized by local governments, which are involved in issuing permits to the facilities. Intense public involvement is part of the Siting Division's review, but impact assessments of smaller-capacity plants may or may not include public participation.

Colorado

Colorado has no formal environmental-review process or any power-plant siting requirements. The state PUC certifies power plants to operate, and various state-pollution control agencies grant air, water quality, and other environmental permits as required. Public hearings are optional for agency permits and are usually held only when public concern or controversy is evident.

Nevada

On February 20, 1987, the Nevada State PSC adopted a regulation to implement the Utility Environmental Protection Act. The regulation applies to entities that are not public utilities and that apply for permits to construct utility facilities, such as independent power producers. One requirement calls for an EA that includes an evaluation and comparison of all reasonable locations for the proposed utility facility, an evaluation and comparison of all reasonable designs for the proposed utility facility, an evaluation of the no-action alternative, and maps of appropriate scale showing all reasonable locations. Additionally, the environmental review requires an impact analysis, a description of mitigation measures, and a description of the energy requirements of the facility. In addition to meeting the PSC environmental-review requirements, an independent power plant would have to obtain the necessary air, water, and other environmental permits issued by

state (Department of Conservation and Natural Resources) and/or federal pollution-control agencies.

New Mexico

New Mexico has no comprehensive environmental legislation or any power-plant siting requirements. The state Environmental Improvement Division has primacy for issuing air-quality permits but does not issue water-quality or hazardous-waste permits for the U.S. Environmental Protection Agency. A public announcement is made and hearings are held for permitting actions that arouse considerable public interest or response, such as the development of an independent power plant of significant capacity.

Oregon

Oregon has neither a state statute that is comparable to NEPA nor specific environmental legislation regarding power plants. However, Oregon Revised Statutes, Chapter 469.300-.621, Regulation of Energy Facilities, provide a means for reviewing proposed power-plant projects larger than 25 MW through "site certification." A council within the Oregon Department of Energy reviews applications for power-plant projects individually to determine conformance with a basic core of standards defined in Oregon Administrative Rules, Chapter 345, Energy Facility Siting Council Standards for siting applications. The standards are specific to the type of energy resource to be employed at the power-producing facility, i.e., hydro, thermal, wind, etc. Included in the standards are requirements for the protection of public health and safety, evaluation of socioeconomic and land use impacts, recreation and aesthetic considerations, preservation of fish and wildlife, and protection of air and water quality.

The council's real job is to approve, deny or conditionally approve a site certificate. During its review of the project application, the council holds public hearings at which testimony can be presented by individuals or state officials. The record created at the public hearings forms the basis for the council's decision, which is referred to as an order. The order lists conditions the applicant must meet to receive site certification, and it is subject to appeal.

Utah

Various agencies of the Utah Department of Health are responsible for issuing air-quality, water-quality, and hazardous-waste permits. An environmental review of a proposed action is not required, except for information that is necessary to determine the suitability of granting a permit. Public meetings are required at the beginning of the application review for air-quality permitting actions, but are optional for the water- and waste-permitting actions. No *formal* environmental review is required in Utah, and there are no power plant siting requirements.

APPENDIX C

AIR QUALITY

REGULATORY CONSTRAINTS

APPENDIX C

AIR-QUALITY REGULATORY CONSTRAINTS

National Ambient Air Quality Standards

The National Ambient Air Quality Standards (NAAQS) are the linchpins of the U.S. air pollution regulatory policy. Under the Clean Air Act (CAA) of 1970, the U.S. Environmental Protection Agency (EPA) was required to establish bilevel ceilings for several "criteria pollutants." Primary standards were defined to provide an adequate margin for protection of public health. Secondary standards guarantee sufficient protection of vegetation, soils, water, and buildings.

The EPA has been charged to periodically reevaluate and, if necessary, modify the NAAQS based on current knowledge of adverse-pollutant effects. The NAAQS (see 40 CFR Pt. 50) in effect since July 31, 1987, are summarized in Table C.1.

New Source Review Procedures

The status of an area's air quality relative to the NAAQS determines which of the two basic regulatory policies of the CAA applies to sources in that area. An area in which the concentration of a criteria pollutant is higher than the relevant NAAQS is subject to "nonattainment area" regulations. Designated "attainment" areas for NAAQS are subject to Prevention of Significant Deterioration (PSD) of Air Quality regulations.

Nonattainment Areas

Within federally established guidelines, states must develop plans by which their nonattainment areas can reduce air pollution to NAAQS concentration levels. Under federal law, all new or modified stationary sources with the potential to emit 100 tons/year or more of any criterion pollutant in a nonattainment area must obtain a permit. The permit must prescribe the lowest-achievable emission rate for the source, which is determined on a case-by-case basis. The permit must also require sufficient "offsets" or reductions by existing sources of pollution to guarantee a net improvement in air quality, or, in the terms of the CAA, "to represent... reasonable further progress" toward compliance with the applicable NAAQS. Finally, all other sources in the state that are owned by the same company must adhere to approved compliance schedules.

Attainment Areas

Areas in which the concentration of a criterion pollutant is less than the relevant NAAQS are "attainment areas." The CAA amendments of 1977 require these areas to comply with PSD requirements in order to maintain and preserve clean air resources. The two key facets of PSD policy are area classification and preconstruction review.

The CAA amendments prescribed a trilevel classification scheme for attainment areas. Each class was distinguished by a pollutant-specific increment of allowable new air-pollution concentrations. The law establishes

Table C.1. National Ambient Air Quality Standards

Pollutant	Averaging time	Primary standard (g/m^3)	Secondary standard (g/m^3)
Sulfur dioxide	3 h	---	1300[a]
	24 h	365[a]	---
	Annual	80	---
Particulate matter[b]	24 h	150[a]	150[a]
	Annual	50	50
Nitrogen dioxide	Annual	100	100
Carbon monoxide	1 h	40,000[a]	---
	8 h	10,000[a]	---
Ozone	1 h	2353[c]	235
Lead	Calendar quarter	1.5	1.5

[a]Not to be exceeded more than once per year.

[b]Particles with an aerodynamic diameter less than or equal to micrometers.

[c]Standard is attained when the number of days per calendar year with maximum hourly average concentrations greater than 235 g/m^3 is less than or equal to 1.

the increment levels only for SO_2 and TSP (see Table C.2) and requires the EPA administrator to promulgate PSD regulations for the other criteria pollutants, a task not yet undertaken.

Table C.2. Prevention of significant deterioration regulations

Pollutant	Maximum allowable increment (g/m^3)		
	Class I	Class II	Class III
Particulate matter[a]			
Annual mean	5	19	37
24-h maximum	10	37	75
SO_2			
Annual mean	2	20	40
24-h maximum	5	91	182
3-h maximum	25	512	700

[a]Total suspended particulate matter.

Initially, almost all attainment areas were assigned Class II designations, which allow for moderate air-quality degradation. Large national parks and wilderness areas were assigned mandatory Class I designations, which severely limit new degradation. In regulating these areas, "air quality related values," such as visibility and ambient concentrations are to be protected. Congress also provided for Class III areas (significant new degradation), although no Class III areas have been designated yet.

Procedures were delineated for EPA-approved state redesignations of all areas, except those with mandatory Class I designations. In general, the status of the applicable increment was to be determined by assessing how emissions from new and modified sources degraded ambient air-quality over and above baseline concentrations of emissions from existing sources.

Although nearly all emissions from new and modified sources are assessed against the baseline concentration, only major new or modified sources to which the provisions apply are subject to PSD preconstruction reviews. Major sources are those that fall in any one of 28 designated categories, including fossil-fueled boilers with more than 250 x 10^6 Btu/h heat input, with potential to emit or increase emissions by 100 tons/year or more, of one or more pollutants (not just TSP or SO_2) regulated under the Act. Also, any source (regardless of type) that could emit 250 tons/year or more of a regulated pollutant is a major source and is subject to PSD review.

A PSD-permit applicant must demonstrate that source emissions will not violate the applicable air-quality increment or the NAAQS. All major sources must install the best available control technology, which represents a case-by-case determination of the most stringent emission limitation achievable under technological and economic constraints. Additionally, each source is responsible for an air-quality impact analysis, including one year of preconstruction, on-site data monitoring.

Emissions Standards

The CAA authorizes the EPA administrator to develop a list of emission limitations for categories of stationary sources that he or she determines may reasonably cause or contribute to health and welfare dangers related to air pollution. EPA has identified 52 categories of sources (including fossil-fuel-fired steam generators, incinerators, and gas turbines) that meet CAA's criteria and has established NSPS emission limitations for sources in the categories (see 40 CFR Pt. 60). These NSPS represent baseline criteria that sources must meet regardless of nonattainment of PSD permitting requirements.

The States' Role

In enacting the CAA and its 1977 Amendments, Congress sought to supplant an array of inconsistent, often inadequate, and contradictory state air-pollution-control programs with uniform minimum national standards. At the same time, Congress wished to preserve the states' traditional prerogatives in managing growth. Congress sought to achieve the desired balance by giving the states primary authority over air-pollution control and by allowing the EPA to establish minimum standards and guidelines for state control.

All states are required to develop control strategies, called State Implementation Plans (SIPs), to protect their clean air resources and to ensure further progress toward compliance with the NAAQS in nonattainment areas. Once EPA approves a SIP, the state has authority to issue permits under that plan. A state may adopt EPA's NSPS, PSD increments, and other standards or may choose to develop its own permitting strategies, provided the adopted criteria are at least as stringent as parallel EPA provisions. In addition, the states have exclusive control over the allocation of their PSD increments among sources competing to use them. The states therefore retain, within the federal parameters, flexibility to accommodate growth while managing their air resources.

APPENDIX D

AGENCIES AND PERSONS CONSULTED

APPENDIX D

AGENCIES AND PERSONS CONSULTED

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