Table II-7. Energy costs in the Washington, D.C. area (1975 prices)

Residual Oil

Percentage Sulfur	Cost per Barrel	Differential
.5 - 1.0	$ 13.10	---
1.0 - 2.0	$ 12.25	$ .85
2.0 - 2.8	$ 11.25	$ 1.85
> 2.8	$ 10.25	$ 2.85

Utility Steam Coal

Percentage Sulfur	Cost per Ton	Differential
.5 - 1.0	$ 42.00	---
1.0 - 2.5	$ 35.00	$ 7.00
> 2.5	$ 30.00	$ 12.00

includes coal handling, combustion system modifications and the necessary changes in the particle emission control system (30).*

Another factor of importance is that much of the low sulfur coal found in the west has an appreciably lower heat value than the Eastern coal. Heat values as low as 7,500 BTU/lb commonly occur, compared to 12,000 BTU/lb (independent of sulfur content) for Eastern coal. Thus, the advantage of low emission from western low-sulfur coal is offset by the fact that more coal must be burned to get the same electric output. Transportation charges may also make use of Western coal unattractive. It is, therefore, not evident that use of low sulfur coal would be cost-competitive with other pollution reduction methods (see also Table II-10).

Cleaning of Coal

Sulfur is either chemically bound to hydrocarbon constituents of the coal (organic) or occurs in minerals (pyrite) associated with the coal (inorganic). Some of the sulfur can be removed from the coal, either by mechanical or chemical cleaning.

In the mechanical cleaning process (33), the coal is crushed and the inorganic impurities are removed by screening and washing, based on the difference in specific gravity between coal (about 1.3) and the pyrite (about 5.0). The organic sulfur cannot be removed by this process.

In Appalachian coal, pyritic sulfur can be as much as 40-80 percent of the total sulfur. Up to 80 percent of the pyrite can be removed by physical cleaning, leaving about 50 percent of the total sulfur (see Figure II-14). Since this coal often has a sulfur content of 2.5 to 3 percent, it can therefore not be reduced below the level required to meet the NSPS without additional emission control. Because coal with inherently low sulfur content contains most of its sulfur in organic form, physical cleaning does not work (see last three cases in Figure II-14). Concurrent benefits from the cleaning operation are increases in heat value** (from 12,000 BTU/lb to 13,400 BTU/lb), and removal of approximately one half of the ash content.

Washing of coal is done routinely, although percentages of coal cleaned has decreased from about 65 percent (332 million tons) in 1965 to 49 percent (289 million tons) in 1973 (32). Cost of mechanical cleaning (ranging from $2.50 to 4.00 per ton) has increased by a factor of four to five since 1968, mainly because of new government regulations of air and water pollution (32). Capital cost for a coal cleaning facility, including cost of environmental controls, may typically be the equivalent of an additional $12/kW in power plant capital cost. Additional costs may be incurred to upgrade power plant electrostatic precipitators. Operating cost is in the range of $0.10 to $0.20 per million BTU (corresponding to 1-2 mills per kW hr) (30).

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* Changes in fuel characteristics often necessitate changes in the emission control systems.

** Some coal is also removed in the cleaning processes so that there is a loss in the basic resource although the energy content per unit coal as burned has increased.

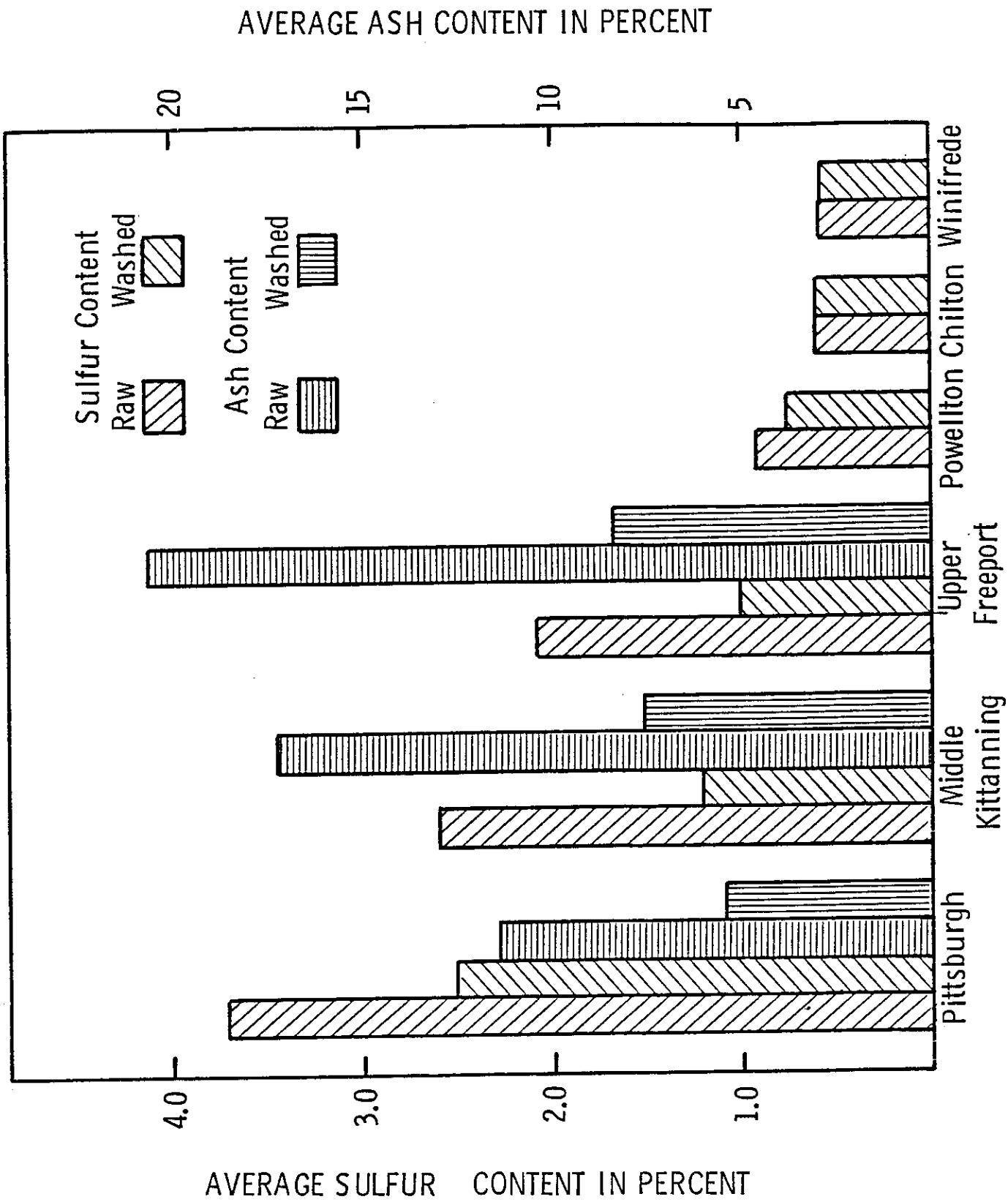

Figure II-14. Washability of some West Virginia coals. From U.S. Bureau of Mines test at 3/8 inch x 0 size and 80 percent yield. Note small reduction in sulfur content for the coals with low inherent sulfur content (last three coal beds).

Chemical cleaning of coal consists of grinding the coal into fine particles, which are treated with a reagent under controlled conditions of pressure and temperature. Both inorganic and organically bound sulfur can be removed by this process. The removal efficiency depends on a number of physical and chemical properties of the process and the coal. The technology is not commercially available, but is being pursued as an EPA development program (34). Chemical coal cleaning will probably be expensive and not available until the 1980's (see Table II-10).

Conversion by Coal Gasification

There are several ways of producing gas from coal (34,35). Generally, the coal is crushed and screened before being subjected to high temperatures (1,000 to 3,000 °F) and pressures (atmospheric to 1,000 psi). The end product of the various processes usually fall into one of the following categories:

- low BTU gas, heat values 100-200 BTU/cu ft
- medium BTU gas, heat values 300-500 BTU/cu ft
- high BTU pipe line quality, synthetic natural gas (SNG), heat value around 1000 BTU/cu ft.

Coal gasification technology for power plants probably can not be developed until the middle 80's, although numerous small systems are in operation around the world. The economics of coal gasification have been studied extensively (30,35). Although great uncertainty exists in the projections, it now seems that these systems will not be cost-effective in comparison to other available fuel and control options (see Table II-10).

Conversion by Coal Liquefication

Liquid fuels can be prepared from coal by several different processes. For power plant applications, several processes that hydrogenate coal to a liquid have shown promise (34,35).

Commercial application of coal liquefication for power plant use is possible by the mid 1980's. Cost estimates are uncertain, but it appears that costs will be high, and the technique will probably not be competitive with the other techniques shown in Table II-10.

Fluidized Bed Combustion

In a fluidized bed combustion system, a grid or distribution plate at the bottom of the boiler supports a mixed bed of granular limestone or dolomite and pulverized coal (36,37,38). High velocity combustion air (2-5 fps) is blown up through the bed suspending or fluidizing it. Because of the thorough mixing and large contact area of fuel and air throughout the bed, an evenly distributed, complete combustion can be supported at a lower temperature than in a conventional boiler. The heat generated in the bed can be removed by heat exchanger directly in the bed as well as in the heated gas flow.

Most of the SO_2 produced by the combustion is removed by reaction with the limestone or the dolomite in the bed. The limestone or dolomite can be regenerated for repeated use in the boiler. The advantages of the fluidized bed system over conventional boilers include:

- high heat release rates and transfer rates in the bed which
  - -- allow lower temperatures to be used (e.g., 1550-1750° F) than in a conventional boiler (e.g., 2700° F) resulting in lower NO_x emissions
  - -- allow boiler size to be reduced by as much as 50% resulting in lower construction cost
- removal of SO_2 directly at the combustion source.

Sulfur removal efficiencies of 90-95 percent have been measured on experimental units using a limestone or dolomite sorbent. Nitrogen oxides are generally emitted at levels of 0.3-0.6 lb/million BTU, well below the NSPS of 0.7 lb/million BTU. Particulate emissions can be high for fluidized bed systems, and are very sensitive to bed operating conditions.

Fluidized beds can be operated at atmospheric pressure or pressurized. In a pressurized system, a gas turbine cycle can be combined with the steam turbine cycle, with possible operating efficiencies in the 40% range. The feasibility of this system depends on adequate removal of particulates upstream from the gas turbine.

Atmospheric pressure fluidized bed coal combustion systems for large power plants will probably be operational in the mid 1980's and may well prove to be less expensive than current combustion technology (Table II-10).

Flue Gas Desulfurization (FGD)

Engineering development of flue gas desulfurization systems (scrubbers) will probably receive a major impetus from the NSPS requirement for SO_2 reduction of the uncontrolled emissions. FGD systems use a sorbent, usually lime (CaO) or limestone ($CaCO_3$) to absorb or react with the SO_2 (39,40,41,42). The sorbent can be discarded after the use or regenerated for repeated use. The most common FGD systems are non-regenerable. The resulting sludge (consisting of a mixture of fly ash, calcium sulfite, calcium sulfate, and water) must be disposed of either in settling ponds or (if treated with a fixative) in a landfill tract. This disposal can be a significant environmental problem.

A typical 1000 MW plant, burning 3.5 percent sulfur coal with 12 percent ash content (as fired) with a lime scrubber removing 90 percent of the SO_2 will generate about 200 tons of settleable slurry and ash per hour, 60 percent of which is calcium solids. The settled material (slurry and ash) has a specific gravity of 1.31 (with 60 percent water content), so that the volume created is about 140 m^3/hr. For a lifetime of plant operation, assumed to be 127,500 hrs, this amounts to a volume of $1.77 \times 10^7 m^3$, or a settling pond 40 feet deep with an area of about 360 acres. Implicit assumptions in this calculation are: 75 percent of ash content becomes fly ash, 99.5 percent of particulates are removed in the precipitator, heat rate 9000 BTU/kWh, heat value of coal 12,000 BTU/lb, giving coal consumption of 375 tons/hr. For a

limestone system, the calcium solids are 15 to 20 percent more than for the lime system (43).

The most important regenerable systems are the magnesium oxide (MagOx) and the Wellman-Lord sodium sulfite process. In a regenerable system, the sulfur is removed from the sludge (or liquid in certain processes) and converted to a marketable product such as sulfuric acid or elemental sulfur. The sorbent medium is reused. The 1000 MW plant described above will generate about 775 tons of 98 percent sulfuric acid per day using the Magnesium Oxide process. In the sodium sulfite processes about 275 tons of sulfur is generated per day, and about 90 tons of sodium sulfate. About 5500 tons of particulate slurry (15 percent undissolved solids) representing the ash, will also have to be disposed of per day. The catalytic oxidation process will generate about 950 tons of 80 percent sulfuric acid (about 800 tons of dry ash will have to be disposed of per day) (43).

There has been a great deal of controversy over whether SO_2 scrubbers are reliable, and whether or not they constitute "available technology" as opposed to "experimental technology." According to the National Academy of Engineering, FGD can be considered "available technology" if it can operate continuously for one year with no more than 10 percent down time. Most of the early problems with FGD systems are being solved to provide acceptable reliability and efficiency at the high temperatures and large flow volumes of large steam electric plants. However, while the terms of the NAE's definition are increasingly being met the controversy continues.

The status of FGD systems is shown in Table II-8 (44). There are 139 systems in operation, under construction, or planned as of July 1978, representing close to 60,000 MW of generating capacity (total fossil-fueled generating capacity of all private and public utilities was about 532,000 MW in 1978) of which 250,000 MW, or 47 percent is coal-fired. Scrubber systems are installed on about 6 percent of present coal-fired capacity. The SO_2 removal efficiency is generally in the 80-90 percent range, and reliability of the more recent installations approximates 90 percent (44).

Table II-9 shows the various processes selected as of 1978, and a projection to 1986. It can be seen that the preferred system is, and will continue to be, limestone. Non-regenerable lime and limestone systems constituted 96 percent of FGD systems installed in new plants and 83 percent of FGD systems retrofitted into old plants (44). About 80 percent of present installations are on new power plants (the remainder are retrofits), and by 1986 the percentage of new installations will increase to 84 percent. Present projections (44) indicate that by the end of 1986, 16 percent of the coal-fired capacity will be controlled by FGD. This situation could be changed if the 85 percent scrubbing requirement is retained in the New Source Performance Standards.

The cost of SO_2 control technologies have been studied extensively (43, 45,46). Costs to be considered are not only capital costs and operational costs in the conventional sense, but also costs associated with the environmental impacts each one of the methods will create. As discussed above, for non-regenerable scrubbers, there will be waste disposal problems; for regenerable scrubbers, some waste disposal may be necessary; for coal processing, there may be problems of water availability and pollution. Disposal of solid waste, such as fly-ash and sludge will be covered by regulations to be

Table II-8. Status of SO_2 scrubber system applications as of July, 1978

Status	Number of Units	MW Capacity
Operational	40	14,440
Under Construction	42	16,834
Planned:		
Contract Awarded	21	10,708
Letter of Intent	3	1,960
Requesting/Evaluating Bid	4	2,255
Considering only FGD systems	29	13,232
TOTAL	139	59,429

Table II-9. SO_2 scrubber system selection in terms of MW capacity

Process	Total MW of Installations 1978	1986
Lime	6,070	15,581
Limestone	7,426	26,766
Lime/Limestone	20	680
Magox	120	846
Wellman-Lord	429	1,855
Others	375	2,546
Not Selected	---	11,155
TOTAL	14,440	59,429

Table II-10. Cost of SO_2 control technologies for baseload plants in 1975 dollars

		Basic Plant	Control Technology	Annualized Costs - mills/kWh		
		Capital Cost $/kW	Capital Cost $/kW	Coal	Control Technology	Total Power
Conventional Boiler						
Coal Fired:						
High Sulfur Coal (>2.5% S)	(TVA)	500 - 700	0	10.8	0	34.4
Medium Sulfur Coal (1-2.5% S)	(TVA)	510 - 710	0	12.6	0	36.5
Low Sulfur Coal (<1.2% S)	(TVA)	520 - 720	0	15.2	0	39.3
Low Sulfur Coal	(EPRI)	375 - 455	0	12.5		
	(ERDA)	294 - 404	0	13.0-15.0		
Physical Coal Cleaning	(TVA)		12.0	10.8	1.5	35.9
Chemical Coal Cleaning	(TVA)		75.0	10.8	4.5	38.9
Flue Gas Desulfurization:						
Lime/Limestone	(TVA)		48.9	10.8	3.3	37.7
	(EPRI)		110-170	10.0	6.0-7.5	
	(ERDA)		72.0	11.0-13.0	2.6-3.6	
Magnesium Oxide	(TVA)		57.4	10.8	2.6	36.0
Sodium Sulfite	(TVA)		67.8	10.8	4.0	38.4
Unspecified Regenerable	(EPRI)		185-280	10.0	7.0-9.5	
New Fuels:						
Coal Gasification w/Steam Turbine	(TVA)	500 - 655	-	10.8	6.8-7.6	41.3
	(EPRI)	760 - 1000 245 - 300	205-700*	10.0	0	
Coal Gasification w/Combined Cycle	(EPRI)	190 - 260	175-600*	8.0	0	
	(ERDA)	395 - 555	-	8.5	0	
Coal Liquefaction	(TVA)	N/A	-	-	-	N/A
	(EPRI)	375 - 500	-	10.0	-	
Fluidized Bed Boiler						
Atmospheric	(TVA)	632	-	10.8	-	32.9
	(EPRI)	450 - 655	-	10.0	-	
	(ERDA)	389 - 409	-	11.0-13.0	-	
Pressurized	(TVA)	723	-	10.8	-	38.4
	(ERDA)	332 - 462	-	11.0-13.0	-	

*Covers a range of low and medium BTU processes. TVA assumes 0.80 capacity factor; EPRI 0.65; ERDA variable over life of plant, average about 0.60.

Footnote to Table II-10

(a) Data labeled TVA has been adapted from (33) and adjusted to a high sulfur coal cost of $30/ton and low sulfur coal cost of $42/ton. Heat values assumed to be 12,500 BTU/lb and 9,025 BTU/kWh. The TVA data for flue gas desulfurization systems (scrubbers) are derived in (43). A base loaded plant of 500 MW capacity is assumed, with an operating life of 30 years over a declining operating profile (total of 127,500 hours). A 3 year construction schedule ending in mid-1975 is assumed at a mid-Western location. For the midpoint of construction the Chemical Engineering Cost Index is 160.2, inflation factor from 1975 to 1977 is about 1.2 (20 percent). Solid waste disposal costs assume conditions existing in 1975. Coal is assumed to have 12% ash content, oil is 18,500 BTU/lb with ash content of 0.1%. Additional cost assumptions, including recovered cost for by-product sales, are found in (43).

Only the TVA costs have been carried forward to total annualized costs in mills/kWh. EPRI and ERDA costs (48) are also 1975 costs. EPRI assumes capacity factor of 0.65 and coal cost of $1/million BTU. ERDA has a variable capacity factor over the plant lifetime (average about 0.6) and coal cost varying between $0.68 and $0.92 per million BTU.

PEDCo Environmental, Inc. has recently (44) collected cost data for existing scrubber systems, and adjusted cost reported by utilities to a common July 1, 1977 basis incorporating the following:

- Capital cost based on gross capacity, annual expenditures on net.
- Particulate control costs deducted, but regeneration and by-product recovery facility costs included. Replacement power costs not included.
- Capital cost of modification or installation of equipment not part of the FGD system included if required for operation of the system.
- Indirect charges adjusted to provide for engineering, field expenses, legal services, insurance, interest during construction, allowance for start-up, taxes, and contingencies.
- Annual cost adjusted to 65% capacity factor.
- 30-year life for new systems, 20-year life for retrofits.
- Sludge disposal costs adjusted to include SO_2 waste disposal (not fly-ash) over the anticipated lifetime of the system.

Some of the results of this analysis are:

	Average Adjusted Costs	
	Capital, $/kW	Annual, mills/kWh
All systems	95.8	5.53
New systems	87.6	5.13
Retrofit systems	103.4	5.92
Lime	94.1	7.03
Limestone	87.0	4.55

(b) Covers a range of low and medium BTU processes.

promulgated by EPA under authority of the Resource Conservation and Recovery Act of 1976 (RCRA). There are indications that EPA may designate fly-ash and scrubber sludge as hazardous wastes. If so, disposal cost could reach $25 to $30 per ton of fly ash or sludge (47). Cost recovery through sale of useful by-products from some of the processes also present an estimating uncertainty. Equipment maintenance problems present another area of uncertainty.

Although many scrubber systems are in full scale operation there is little solid cost experience to build on because so many of the installations involve retrofitting, with all its site specific conditions, or developmental installations, often with shared financing, which makes it difficult to assess true costs of installation and operation.

Table II-10 gives an overview of the effect of SO_2 control techniques on the cost of electric power. The values are developed from a number of sources (33,46,48) and provide a rough indication of relative costs. The absolute cost figures have considerable uncertainty attached to them and also depend on factors which are highly variable, such as fuel costs and transportation costs.

The current situation regarding SO_2 abatement can be summarized as follows: Choice of an SO_2 control strategy is complicated by the interaction of operational and economic factors, the availability of low sulfur fuel, the uncertainties associated with the new NSPS requirements for SO_2 scrubbing and the variability of emission regulations throughout the U.S. However, several conclusions can be drawn from the current knowledge of SO_2 emission control technology.

Using currently available technology, all coal-fired electric power plants in Maryland could operate in compliance with present State emission standards by 1985.

Between now and 1985, only about half of the projected national coal demand can be supplied with low sulfur coal. Therefore, SO_2 emission standards can only be achieved through a combination of low sulfur coal use, coal-cleaning, and FGD technology. The utilities in Maryland will reflect this mix in their plant design and operations.

In new installations there is no major economic penalty associated with FGD (as opposed to retrofits which are much more expensive). Cost of FGD starting with high sulfur coal is comparable to, or slightly below, the price of electricity using low sulfur coal, despite the large differential in capital costs.

F. Mathematical Modeling

Mathematical modeling is becoming increasingly important for air quality predictions and maintenance studies. Section 320 of the 1977 amendments to the Clean Air Act (49) recognizes modeling as a necessary tool, especially as it relates to the problems of prevention of significant deterioration (PSD) of air quality.

The Gaussian plume equation is currently the most widely used model (50). It is based on the idea that, over a short time, a plume of pollutants will tend to move with the wind in such a manner that the average density has a normal (i.e., Gaussian) distribution about the mean wind direction both in the

lateral direction and in altitude. It is further assumed that the pollutant is conservative, i.e., that there is no loss of pollutant due to chemical reactions or ground deposition, and that the plume will be perfectly reflected from the ground.

Attractive features of the Gaussian plume model are its simplicity, and the fact that the required input parameters are readily measurable. More complex models for pollution dispersion, based on flow field analyses and solution of standard turbulent diffusion equations, have been developed (51). However, they require input data that are not readily available, and they do not, in general, give consistently better results than the simple Gaussian model.

In the Gaussian model the ground-level concentration (GLC) is directly proportional to the emission rate, which again is directly proportional to the sulfur level in the fuel and to the fraction of SO_2 not removed by the scrubber. Therefore, the data presented can easily be scaled to other values of sulfur content and scrubber efficiency through use of the factor

$$F = S\left(1 - \frac{\text{scrubber efficiency in percent}}{100}\right),$$

where S is the sulfur content of the fuel.

The general shape of the ground-level concentration along the plume centerline as a function of the downwind distance x is shown in Figure II-15. We can see that c, the GLC, is zero near the source, rises to a maximum, c_{max}, at a distance x_{max}, and then slowly decreases to zero as x increases (for large values of x the applicability of the model is in question, as will be discussed later). In general, c_{max} is inversely proportional to the emission rate Q which in turn is proportional to the power level and the F factor discussed above. As a general approximation, c_{max} is inversely proportional to the square of the effective stack height (h_e). The dependency on wind speed, v, is more complex since h_e also depends on wind speed. The effective stack height is also a function of the difference, ΔT, between stack gas temperature and the ambient temperature, in such a way that h_e decreases with decreasing ΔT. Therefore, a decrease in ΔT generally will result in an increase in c_{max}. Thus, it is conceivable that a flue gas scrubber, while removing SO_2 (i.e., reducing the emitted quantity of pollutants) may lower the flue gas exit temperature (and therefore the effective stack height) to the point where the GLC actually increases. This is a paradoxical situation, where removal of pollutants decreases the ambient air quality. These basic parametric relationships are important to the subsequent discussion of air modeling results as they apply to future siting decisions.

In view of its central position in air quality assessments, the limitations of the Gaussian pollutant dispersion model must also be understood. There is a limit to the distance over which the model can be applied with any degree of confidence even for flat terrain. Two basic factors must be considered:

- The calculations are usually based on meteorological conditions at a point at or near the emission source. It is unlikely that these conditions persist over an infinite range downwind of the source. Both wind direction and the state of the atmosphere with respect to

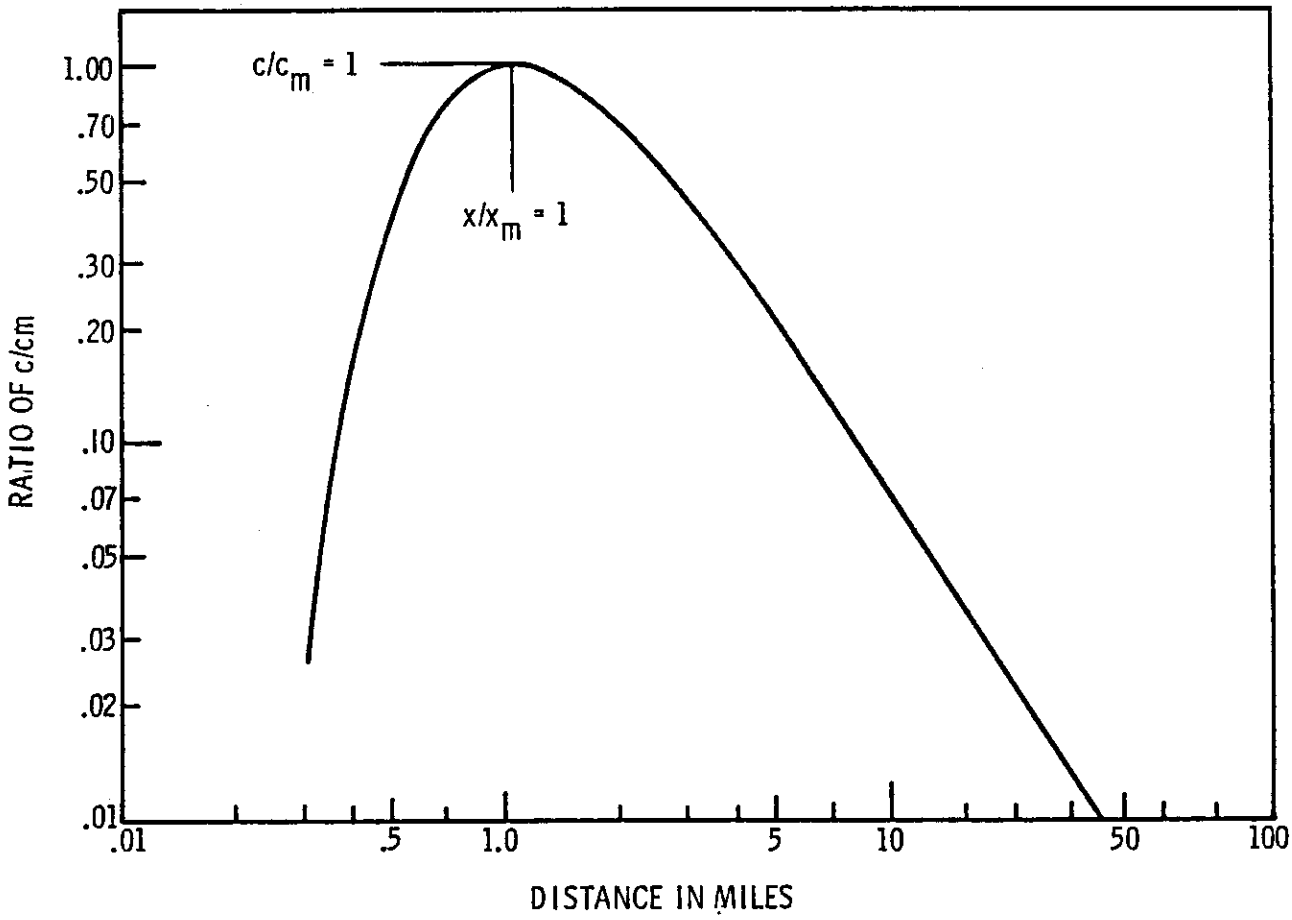

Figure II-15. Representation of the Gaussian plume equation.

$$c_{max} = \frac{Q}{\pi v a_1 a_2} \left(\frac{\alpha}{2}\right)^{\alpha/2} \frac{\exp\left(-\frac{\alpha}{2}\right)}{\left(h_2/a_2\right)^{\alpha}} \quad \text{when } \alpha = 1 + \frac{b_1}{b_2}$$

The a's and b's are coefficients determining the dispersion parameters

$$\sigma_y = a_1 x^{b_1}$$

$$\sigma_z = a_2 x^{b_2}$$

The graph has been normalized to present ratio of actual ground-level concentration c to the maximum c_m, as a function of actual distance x to the distance x_m at which the maximum concentration will occur. The numerical values apply to Brookhaven C stability class. Note logarithmic scales.

turbulence and other parameters affecting mixing will change. The functional form assumed for the dispersion parameters (σ's) can also not be expected to hold indefinitely for larger values of x.

- The assumption of a conservative pollutant does not hold ad infinitum because of dry ground deposition, wash-out, and chemical processes. This problem is currently under investigation and some of the conversion processes were discussed earlier in connection with the sulfate problem (p. II-24).

Other problems with the Gaussian plume dispersion model appear under certain meteorological conditions. These conditions include low wind speed, where the concept of a continuous plume is not valid and stable atmospheric conditions, where the "standard" dispersion coefficients to an elevated plume rising from a tall stack are not necessarily applicable.

There is also a problem in applying the Gaussian model in rough (non-flat) terrain where topographical features strongly affect the air flow. A number of Gaussian rough terrain models are in common use (51). Most of them are rather primitive, in the sense that they take the Gaussian plume and modify the effective height of the emitting source by some fraction of the height of the terrain at the point of plume impingement. This type of model generally does not agree with measured GLC, [e.g., Power Plant Siting Program studies at Luke, Maryland (52)].

The general Gaussian model has been tested extensively in the Maryland Power Plant Siting Program for three different power plants and for various algorithms for determining stability classes, dispersion parameters and plume rise. For flat terrain the best model was found to agree with measured concentrations to within a multiplicative factor of 2 in about 70 percent of the 126 cases that were tested (53).

The thrust of current development in the Siting Program is toward mathematical models that consider actual flow patterns. Flow patterns, air pressure distributions and velocity profiles are studied in wind tunnels simulating the existing meteorological and topographic conditions. It is expected that this ongoing work will lead to a better understanding and formulation of the underlying physical principles of dispersion. In practice, the influence of local features (i.e., local emissions, and local topography and meteorology) can create great differences between actual point measurements and model predictions.

Plume measurements have generally been confined to ground level. It is possible to make airborne measurements, but these are expensive and beset with practical problems such as helicopter rotor downwash interference and instrument time response problems from fixed wing aircraft. Improved measurement methods are expected to aid materially in future model development. The Power Plant Siting Program, in cooperation with NASA, has been using Lidar (a laser-type remote sensing instrument) for plume measurements (54). The Lidar is useful in studying details of plume rise (near the stack), vertical plume structure, and three dimensional development along the plume. The demonstrated capability of Lidar to track particulates is currently being extended to chemical pollutants such as SO_2 and photochemical oxidants.

G. Regulatory Effects

The Clean Air Act Amendments of 1977 are of major importance in that they give specific legislative direction to "prevention of significant deterioration," one of the most controversial concepts of air pollution control.

The amendments also give focus to other control approaches which have developed over the years since the previous amendment to the Clean Air Act was passed in 1970. Some of the most significant areas of importance to power plant siting and operation are discussed below.

Stack Height and Intermittent Control

One of the air pollutant control techniques proposed (and in some cases implemented) by electric utilities was the use of tall stacks, switching of fuel, and switching of load between plants in such a manner that the air shed impact, in the form of pollutant GLC was minimized.

EPA argued against the acceptability of this method on the ground that tall stacks and switching of load to other plants in a utility system did not diminish emissions, although a better air quality, as defined by GLC was attained by spreading the pollutants.

The new act essentially eliminates the use of these dispersion techniques by denying credit for pollution abatement by these techniques. In particular, credit is denied for stack height exceeding "good engineering practice," which is "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash eddies and wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." (Section 123 of the Act) EPA has recently proposed a set of regulations pertaining to tall stacks (55). The height for good engineering practice is interpreted as the height of the structure plus 1.5 times the lesser height or width of the structure. "Nearby" is taken to be a distance up to 5 times the height or width of the structure, but not more than 0.5 miles (0.8 km) away unless a greater height is necessary to avoid the excessive concentrations referred to above.

The height of the source, i.e., the structure of a power plant, is typically such that stack height is limited to the 500 to 600 feet range. It is not clear at this time whether cooling towers (which range up to 450 feet tall) are to be included as source structures. If they are (and there are often good engineering reasons for including them), then the law provides no practical limitation upon stack heights. If they are not, then the stack height limitation may be important to meeting the prevention of significant deterioration criteria as will be discussed below.

Non-Attainment Areas

When an area exceeds Federal ambient air quality standards, it becomes a non-attainment area, and no further growth in pollutant emissions from major

sources is allowed.* To permit new industries to locate in such regions, the EPA (under the Clean Air Act) has promulgated a policy of "emission offsets" (49). A new power plant, if it wishes to locate in such a region, must not only meet an emission limitation specified as the Lowest Achievable Emission Rate (LAER) for that source, but must also provide for sufficient reduction of emissions from other sources (its own or others) in the area to offset its new emissions, so that "reasonable progress toward attainment of the applicable NAAQS" is made.** Any power plant, outside the non-attainment region, producing a "significant" decrease in the air quality of the non-attainment region, is also subject to an offset requirement.

Although the idea behind this policy is to satisfy the competing needs of growth and maintenance of air quality, it entails several significant consequences. First, it appears to give industries now emitting major amounts of pollutants the power to sell "pollution rights." That is, they could sell the right to clean up their output levels to whomever they chose (or refuse to do so) for more than the price of the control equipment. In fact, it is possible for a company to be economically responsible for the operation and maintenance of another company's pollution controls. Another consequence is that the economic burden of controls, both for its own plant and the offset plants, would be borne by any new source (as opposed to the sources already located in the area). Thus, unless there are compelling economic considerations for locating in a particular region, power plants will tend to locate far enough away from non-attainment areas so that they will not be subject to an offset.

In Maryland there are presently four pollutants for which non-attainment areas exist: particulates and carbon monoxide (Baltimore and Western Maryland), hydrocarbons, and photochemical oxidants (Baltimore, Washington, and scattered areas elsewhere). Because of the differing sources and nature of these pollutants, different offset policies have been developed.

Any source increasing the concentration of particulates in a non-attainment area by more than 1.0 $\mu g/m^3$ (annual average) or 5.0 $\mu g/m^3$ (24 hour average) is subject to an offset (49). To estimate the implications of this policy for power plants, a typical 1000 MW coal-fired generating station emitting at the new source performance standards (Table II-3) was modeled for "worst-case" conditions. The results indicated that, to avoid an offset, such a plant would have to locate 10-15 miles from the border of a non-attainment area, depending upon the local meteorology.

Photochemical oxidants, because of the regional nature of their emissions and their slow reaction/deposition rates, have been approached from a larger geographic scale. According to a draft EPA policy (56) any major source

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* Although the present discussion will center on power plants, the conclusions will be valid for all large emission sources with similar characteristics.

** The applicant must also certify that all the existing major sources he owns or operates in the same state are in compliance with the applicable emission limitations or are meeting the target dates of a compliance schedule.

(greater than 50 tons/year) locating within an 85 mile circle of Baltimore or Washington would require an offset. When similar circles around Pittsburgh and Philadelphia are considered, most of the State (all except the tip of Garrett and Worcester Counties) is subject to an offset. In this case, the offset is not the for primary pollutant (O_3) but is for a percursor, non-methane hydrocarbons (NMHC). A typical 1000 MW generating station produces about 250 tons/year of NMHC.* The major difficulty in this offset policy is finding controllable stationary sources that can produce an offset. Table II-3, the State-wide total emissions inventory, shows that 77 percent of the NMHC emissions (in 1975) come from mobile sources (automobiles and trucks). When road resurfacing is added, the transportation sector produces 85-90 percent of the total emissions. Clearly, any strategy to control hydrocarbons should include this sector.

These policies are now being used to evaluate the proposed expansion at Sollers Point (100-600 NW of gas turbines). The proposed site is a non-attainment area for particulates, hydrocarbons, and photochemical oxidants. The preliminary site investigation (57) indicates that the plant will have to meet the offset requirements listed above. An output of six hundred megawatts, previously proposed by BG&E, has been ruled unsuitable by the Department of Natural Resources. A detailed site evaluation study now in preparation by Applied Physics Laboratory of Johns Hopkins University will more clearly define available options and requirements. In the 1978 Ten-Year Plan, BG&E listed a proposed installation of only 100 MW (58).

Thus, the existing non-attainment areas in Maryland will influence the siting of future fossil-fueled power plants either by requiring use of an offset or by requiring the plants to locate outside the affected region.

Prevention of Significant Deterioration (PSD)

The most significant change within the Clean Air Act relates to PSD (59,60). The law establishes upper limits on allowable air quality changes for SO_2 and particulates. It designates three classes of areas with differing restrictions on increases in pollution levels. The allowed increases (increments) for each area and the comparable standards are shown in Table II-11. The total increments caused by all users must stay within the specified limits.

The Class I area designation is reserved for regions where it is desirable to maintain the present air quality. Automatically classified within this category are international parks, national wilderness and memorial parks over 5000 acres in size, and national parks over 6000 acres in size. Other areas may be added to this list by the State, in some cases at the suggestion of the Federal Land Manager. Maryland has no Class I areas at this time,** although there are several such areas in nearby Virginia and West Virginia. Figure II-16 shows the mandatory and discretionary areas in and near Maryland that have been mentioned by Federal agencies for possible Class I designation.

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* Emission factor under revision by EPA (28).

** Fort McHenry has been proposed as a Class I area by the National Park Service.

Table II-11. Prevention of significant deterioration of air quality. Maximum allowable increase in ground-level concentration of particulate matter and sulfur dioxide under the provisions of the Clean Air Act Amendments of 1977*

Area Designation	Maximum Allowable Increases $\mu g/m^3$		
	Class I	Class II	Class III
Pollutant:			
Particulate Matter			
Annual Geometric Mean	5	19	37
24-hr Maximum	10	37	75
Sulfur Dioxide			
Annual Arithmetic Mean	2	20	40
24-hr Maximum	5	91	182
3-hr Maximum	25	512	700

* The allowable concentrations must in no case exceed the concentrations permitted under the national primary and secondary ambient air quality standards.

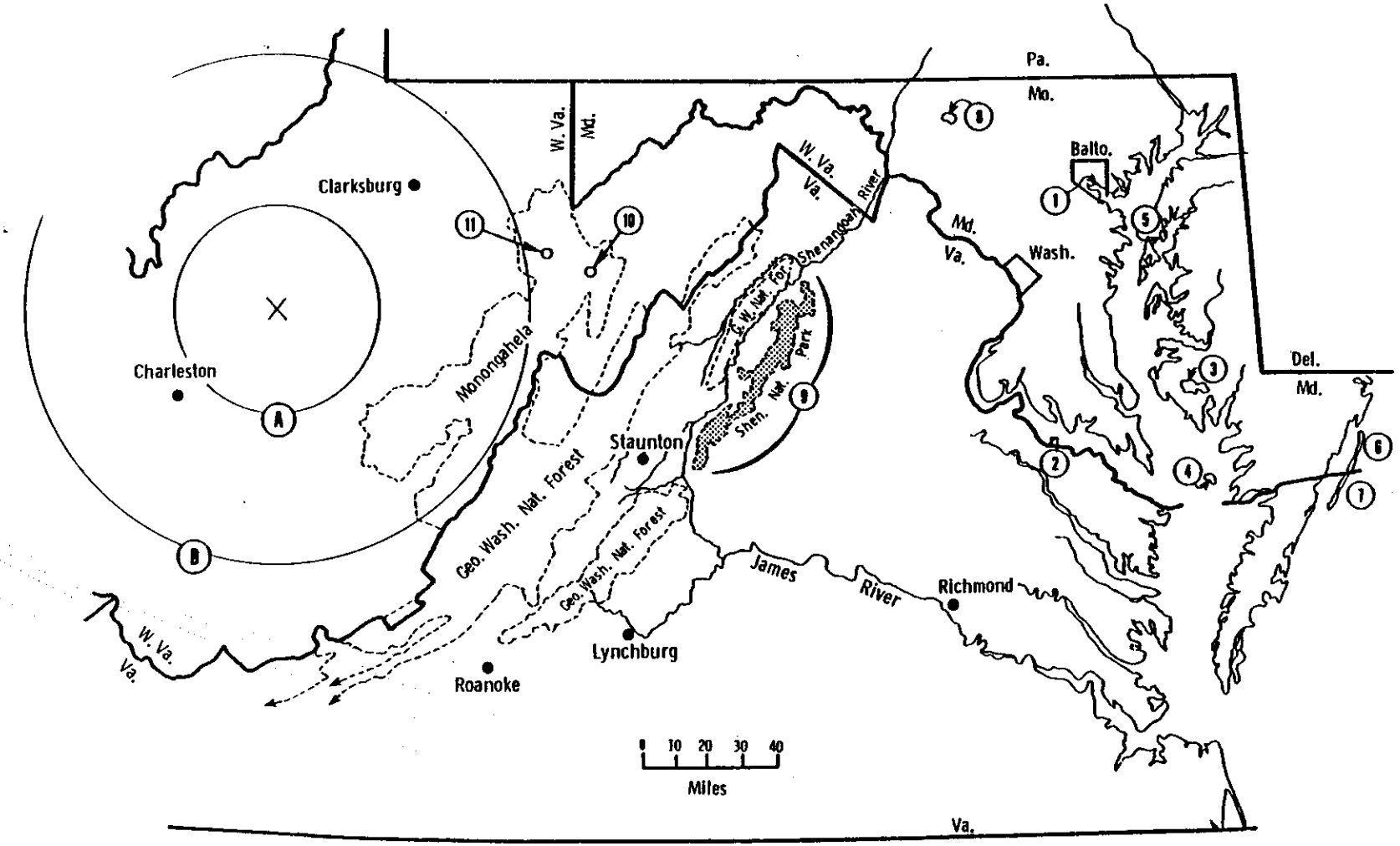

Figure II-16. Mandatory (M) and suggested (S) Class I areas in and around Maryland. There are no mandatory areas in Pennsylvania.

1) Ft. McHenry (S)
2) Washington's Birthplace (S)
3) Blackwater Nat'l Wildlife Refuge (S)
4) Martin Nat'l Wildlife Refuge (S)
5) Eastern Neck Nat'l Wildlife Refuge (S)
6) Assateague Nat'l Seashore (S)
7) Chincoteague Wildlife Refuge (S)
8) Catoctin Mountain Pk (S)
9) Shenandoah Nat'l Pk (M)
10) Dolly Sods (M)
11) Otter Creek (M)

Circle A shows the Class I exclusion area for a 1000 MW power plant located at X burning 1% sulfur coal with an 80% scrubber, and circle B shows the exclusion area for the same plant burning 2% coal (see discussion on p. II-55).

Class II areas have increments allowing moderate industrial growth. All areas of the country not originally classified as Class I start out in this category.

Class III areas are less restricted and may allow fuller industrial development. A Class area may be redesignated Class III only after a process involving the Governor, the legislature, and "general purpose units of local governments." The actual procedure is not determined at this time.

When the allowable increment for an area has been used, an offset policy will probably come into effect. EPA is presently formulating this policy (61). Thus, it may be important to keep this ultimate possibility in mind while evaluating specific plant designs. For example, any coal-fired facility which now burns high-sulfur coal or oil may, during its lifetime, be expected to eventually burn low-sulfur coal or oil (perhaps cleaned to that level). So, it may be advantageous to ensure that the equipment is compatible, or easily convertible, to that type of fuel.

Although the PSD presently applies only to SO_2 and particulates, EPA must establish regulations by August 1979 regarding PSD for hydrocarbons, carbon monoxide, photochemical oxidants, and nitrogen oxides. If national ambient air standards are established for other pollutants at some future date, corresponding PSD regulations must be promulgated within two years of that date.

For power plants which are required to switch to coal as a result of an order under the provision of the Energy Supply and Environmental Coordination Act of 1974, the added concentration due to increased emission will not be applied against the allowable increment for a period of five years. The same consideration applies to plants converting from natural gas as the result of a natural gas curtailment plan implemented under the Federal Power Act.

With the PSD restrictions the question of long-range, interstate transport of pollutants becomes important because a large coal-fired plant, located in Maryland, could use up part of the available increment for up to four states. It is not clear at this time what recourse a state affected by the siting of a source in a neighboring state (and not causing a violation of standard) would have. The present amendments (Section 126) call only for "written notice to all nearby states...at least sixty days prior to the date on which commencement of construction is to be permitted."

To investigate the potential impact of the Clean Air Act Amendments upon power plants within the State, several representative cases have been modeled, using the Gaussian plume model for typical power plants in the following range of variables:

- plant capacity: 100 - 1500 MW
- stack height: 100 - 700 feet
- exit temperature difference: 30°C and 90°C

The lower exit temperature difference is typical for a power plant where the flue gas is not reheated after passing through the SO_2 scrubber, while the

higher ΔT corresponds to a moderate reheat. (It is not yet known whether EPA will allow reheat to be considered in calculations). The 1000 MW power plant used in the modeling has a stack diameter of 35 feet, an exit velocity of 41 feet per second, burns two percent sulfur coal, and utilizes a ninety-nine percent efficient particulate precipitator and an eighty percent efficient SO_2 scrubber for emission control. With these parameters, the numbers quoted for sulfur dioxide concentrations can be converted to particulate levels by dividing the quoted concentration by 5. The SO_2 ground-level concentrations scale directly as power level, sulfur content of the coal, and percent of SO_2 emitted from the scrubber. The calculations are for flat terrain, and thus would not apply in the rough terrain of western Maryland (in rough terrain, the specific locations of mountains, valleys, and stacks must be considered in each individual case).

The annual average ground-level concentration depends primarily on meteorological conditions, as defined by the annual windrose (considering stability class and wind persistency); by the difference ΔT, between the flue gas exit temperature and the ambient temperature; by the physical stack height; and by the power plant emission rate (which depends on power level, in addition to the sulfur content and scrubber efficiency as discussed above). Using the windrose at the Baltimore-Washington International Airport (BWIA) as a representative case for Maryland, the annual average ground-level concentrations were calculated for several plant configurations. These results are summarized in Figures II-17 and II-18, which show the maximum annual average of SO_2 as a function of power generated and stack height. In all cases for moderate stack heights (500 feet), the increase in concentration is less than twenty-five percent of the Class II increment.

Two meteorological situations have been considered in order to establish the worst situation to compare to the 24-hour average increment.

1) Neutral atmospheric stability with high wind (8m/sec) and persistent wind direction.

2) Unstable atmospheric conditions with light wind, typically for 8 hours followed by persistent wind direction and stable conditions for 16 hours.

These conditions occur rarely in Maryland (only a few times a year), but, depending upon location, may occur frequently enough to be the determining factor in a plant siting decision. Results of calculations for these meteorological conditions, shown in Figures II-19 and II-20 for a plant employing reheat, indicate that a 1000 MW plant with a 500 foot stack would be allowed in a Class II area, although a significant percentage of the allowable increase (up to fifty percent) in Class II regions would be used. Thus, depending upon the local frequency of these meteorological conditions, the siting of a power plant might lead to future sources requiring an offset. For conditions other than the two named above, 24-hour average concentrations would typically lie below 30 $\mu g/m^3$ for a 1000 MW plant with a 500 foot stack.

Calculations for the three-hour average indicate it is not a restraining factor for PSD in a Class II area.

The final area of concern, long range transport of SO_2 into Class I areas, is a difficult area to analyze. The Gaussian plume model is not accurate at

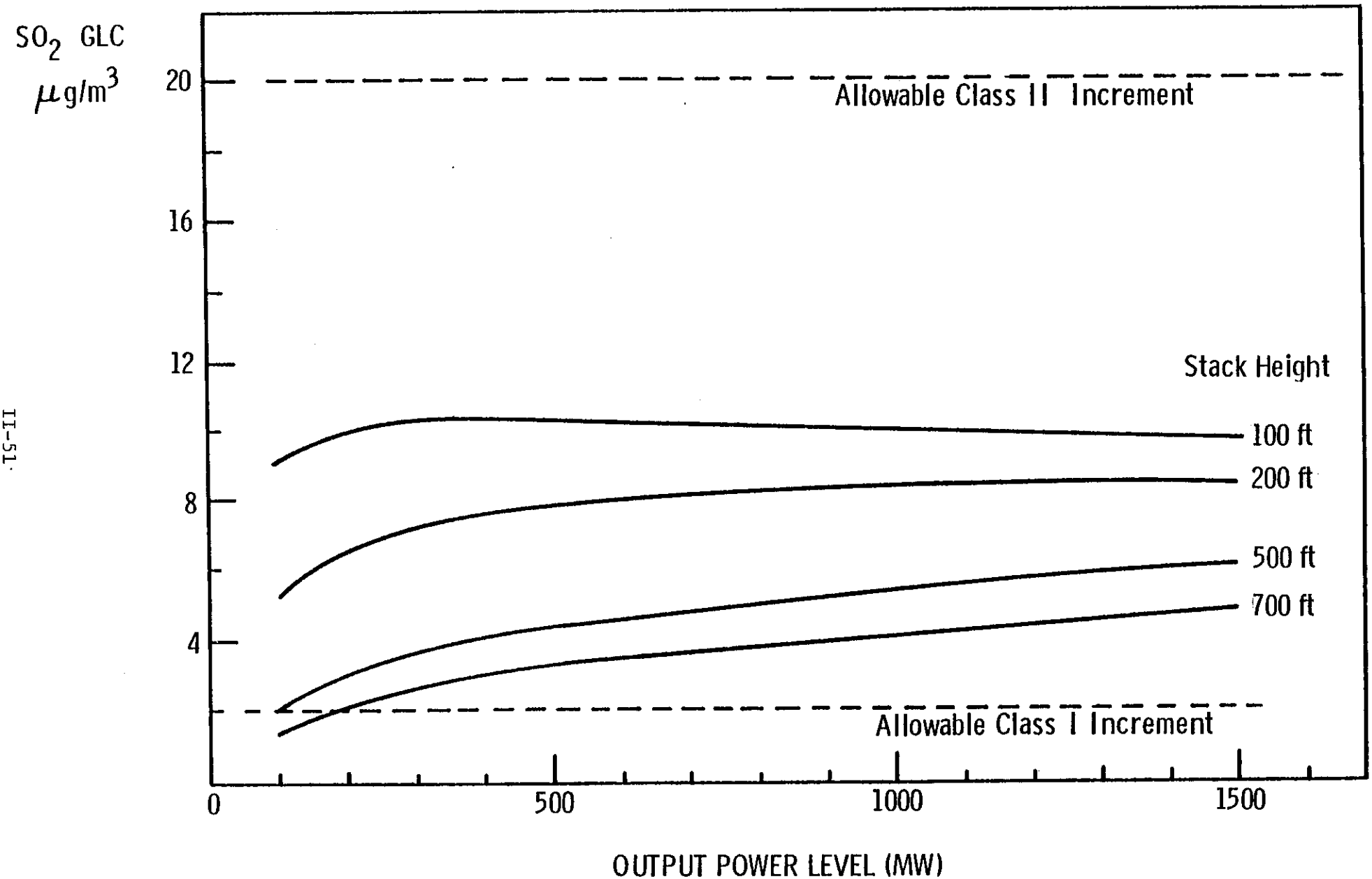

Figure II-17. Maximum annual average ground-level concentration for SO_2 $\Delta T = 30^{o}$ C

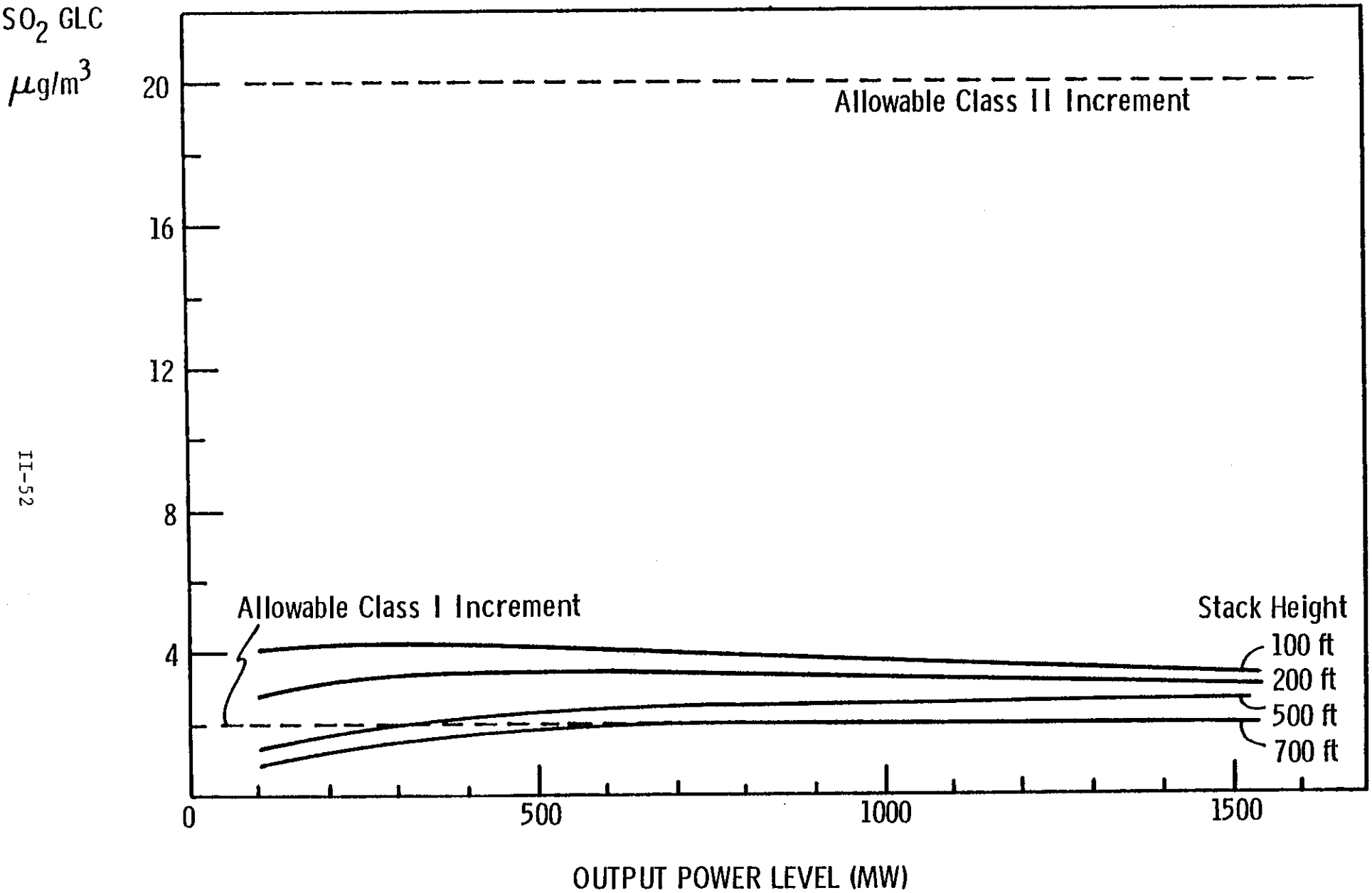

Figure II-18. Maximum annual average ground-level concentration for SO_2 $\Delta T = 90^{o}$ C

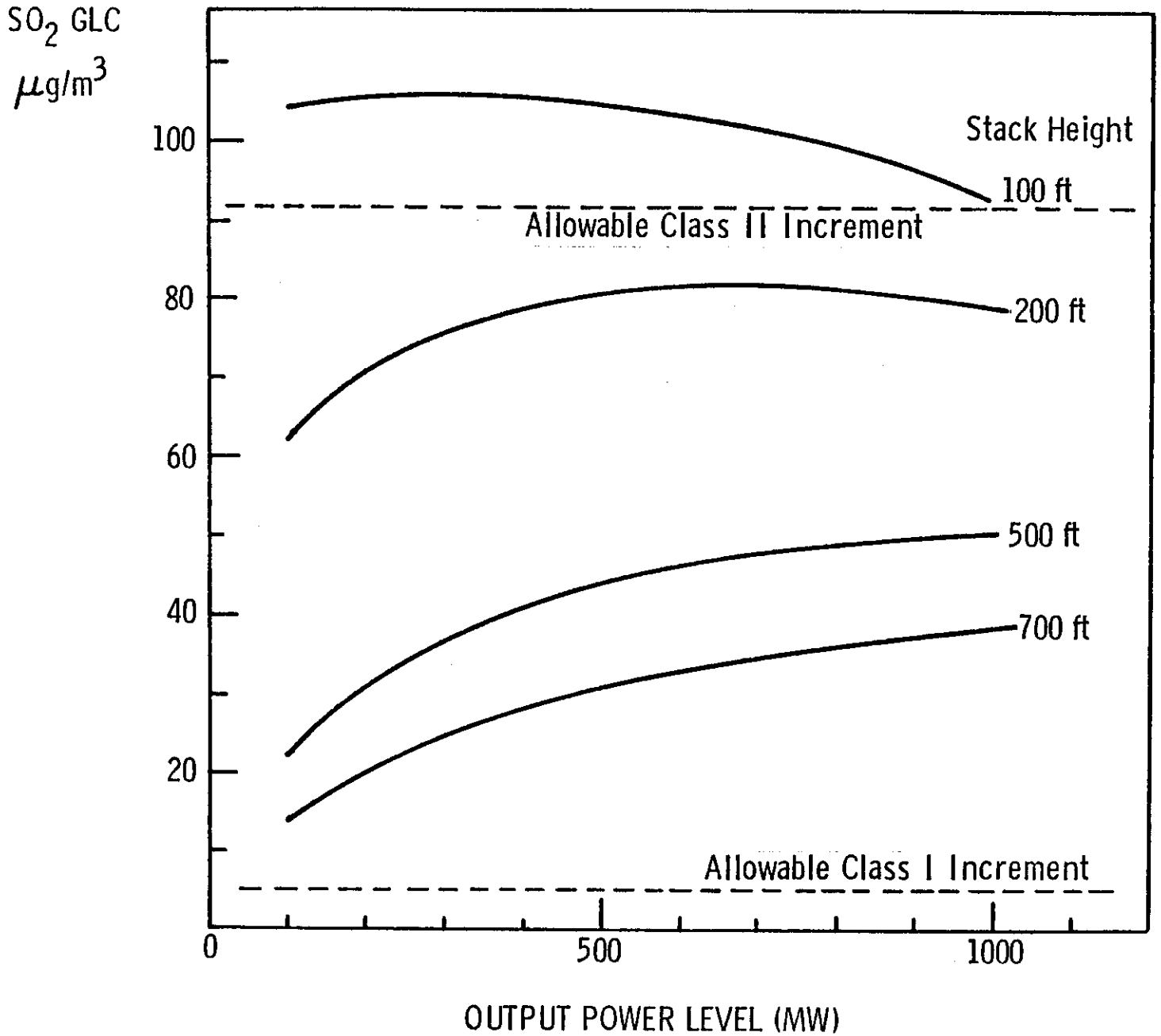

Figure II-19. Maximum 24-hour average ground-level concentration for SO_2
Meteorological Condition 1 $\Delta T = 90°C$

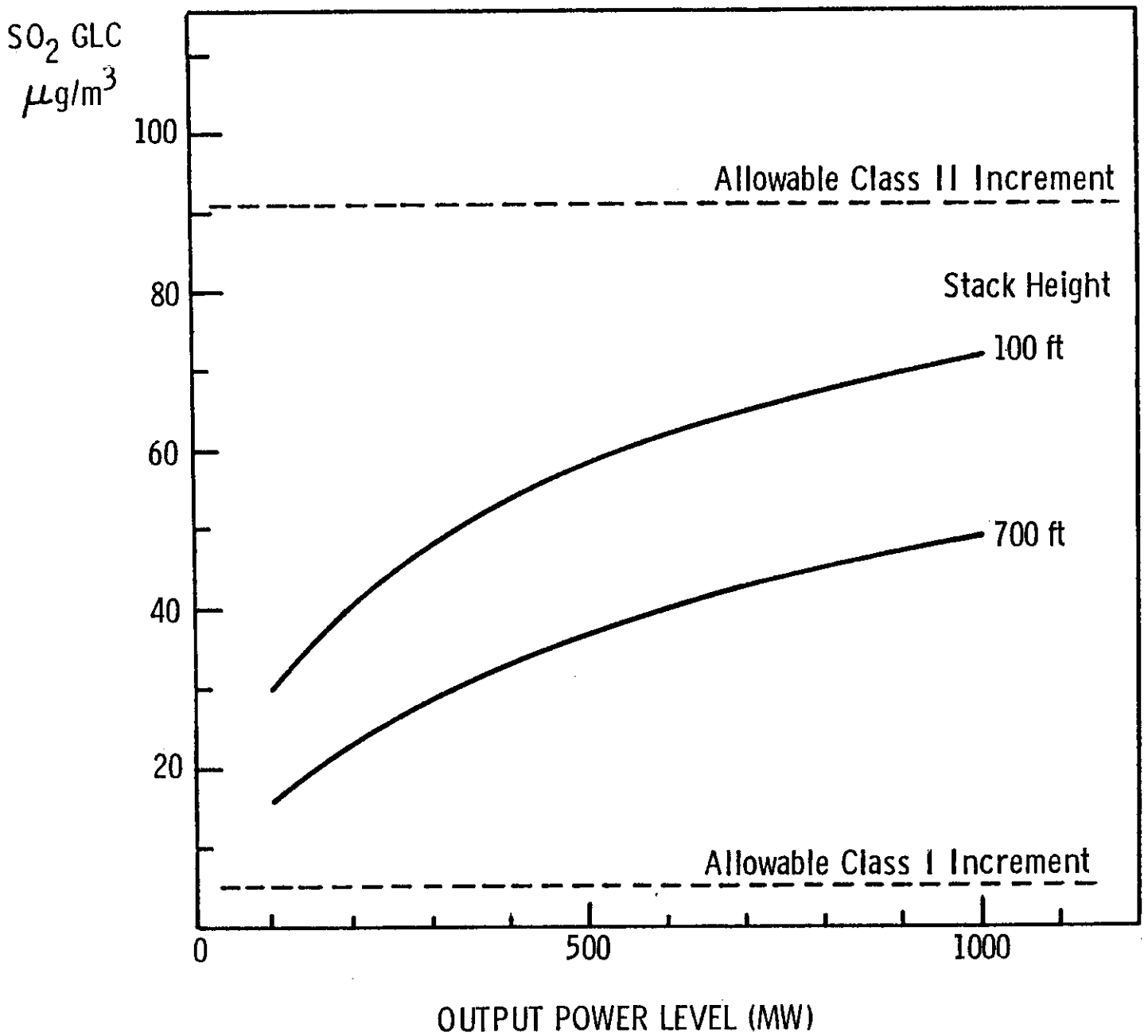

Figure II-20. Maximum 24-hour average ground-level concentration for SO_2 -- Meteorological Condition 2 $\Delta T = 90°C$

distances beyond 20-30 miles (as explained in Section F), the meteorological data necessary for realistic calculations (high level and profiles every 20-30 miles) are not available, and the interaction of pollutant plumes from various sources is not well understood. One indication of this difficulty is the large difference in the annual windrose from National Airport, Dulles Airport, BWI, and Patuxent Naval Air Station (as shown in Figure II-21). Despite the fact that all four airports are located within a 50 mile radius, the windroses are different. A plume emitted at National might change direction by the time it reached Southern Maryland or Baltimore, and vice-versa. Still, by looking at various limiting cases, we can gain insight into the effect of a Class I area upon power plant siting. The two meteorological conditions mentioned above give upper limits to the "zone of influence" (the maximum distance) from which a power plant would be excluded. A more common condition, medium winds (5 m/sec) for 10 hours followed by stable conditions, gives the minimum exclusion distance. The exact exclusion area (to be determined by site specific meteorological studies) would be somewhere between the two. The results of these calculations are shown in Figures II-22 and II-23. Although the Gaussian plume model is not adequate to deal with transport over these large distances, we obtain the following indications (see Figure II-24).

A 1000 MW power plant using a 500 foot stack and burning two percent sulfur coal with an eighty percent scrubber could not be located closer than 90 (and possibly not closer than 200) miles to a Class I area. If the same plant burned one percent sulfur coal, the plant could not be located closer than 40 (and possibly not closer than 75) miles to a Class I area. Thus, the designation of a Class I region in, or nearby, Maryland could:

- limit a substantial portion of the State to allow only the siting of small fossil-fueled plants,
- make the operation of new plants more expensive by requiring the use of low-sulfur in addition to scrubbing, and
- encourage the use of nuclear power because of the two points made above.

In summary, the effects of the PSD provisions of the Clean Air Act will be to:

- limit the increase in pollutant levels,
- require power plants to locate moderate distances away from each other and from other major emission sources, and
- establish power plant exclusion zones around Class I air quality regions.

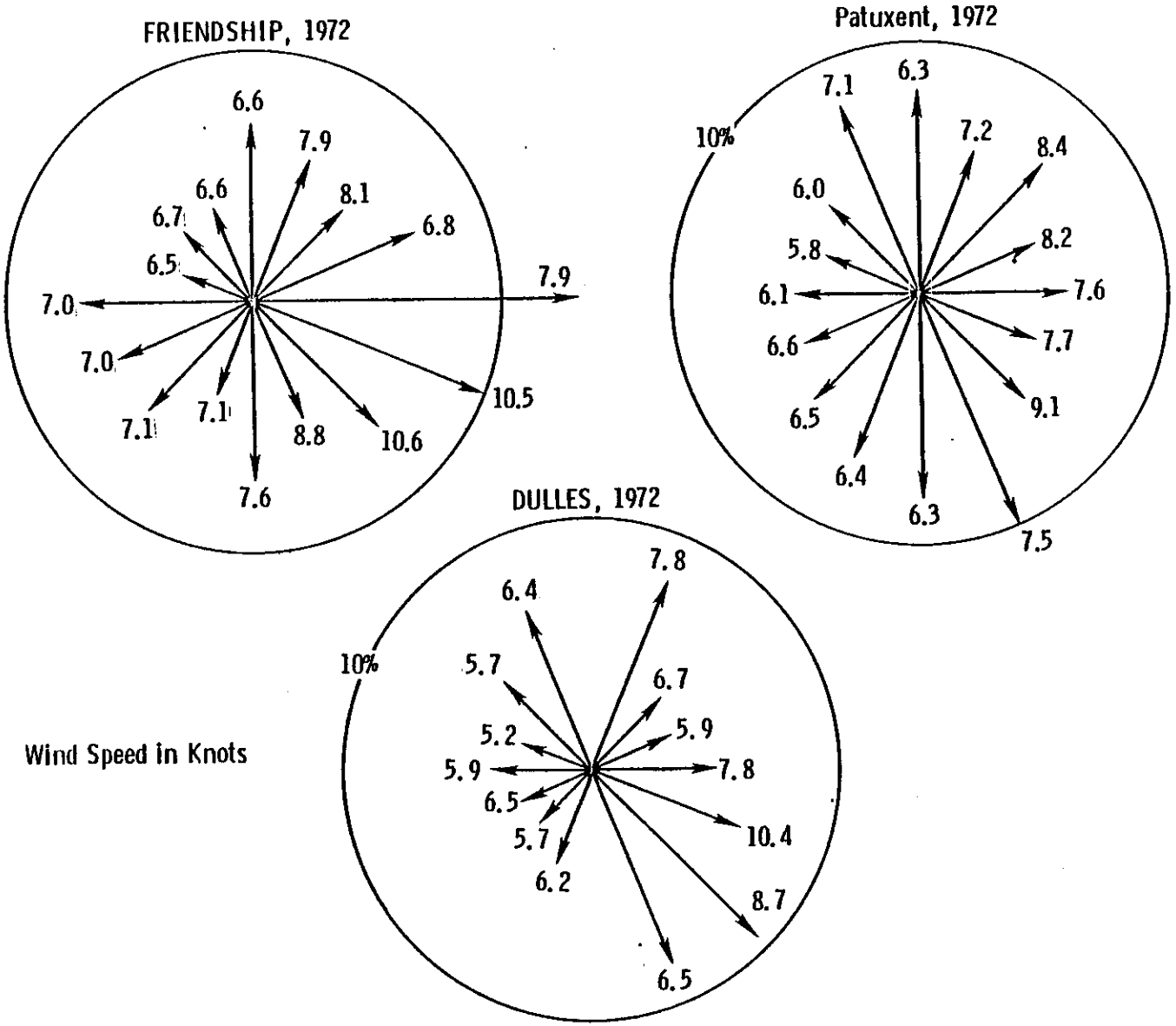

Figure II-21. Annual wind roses for three airports. Length of arrow shows frequency of occurrence (in percent of time - Note 10 percent circle) of wind blowing towards the indicated direction. Number at tip of arrow shows annual mean wind speed (in knots) in that direction.

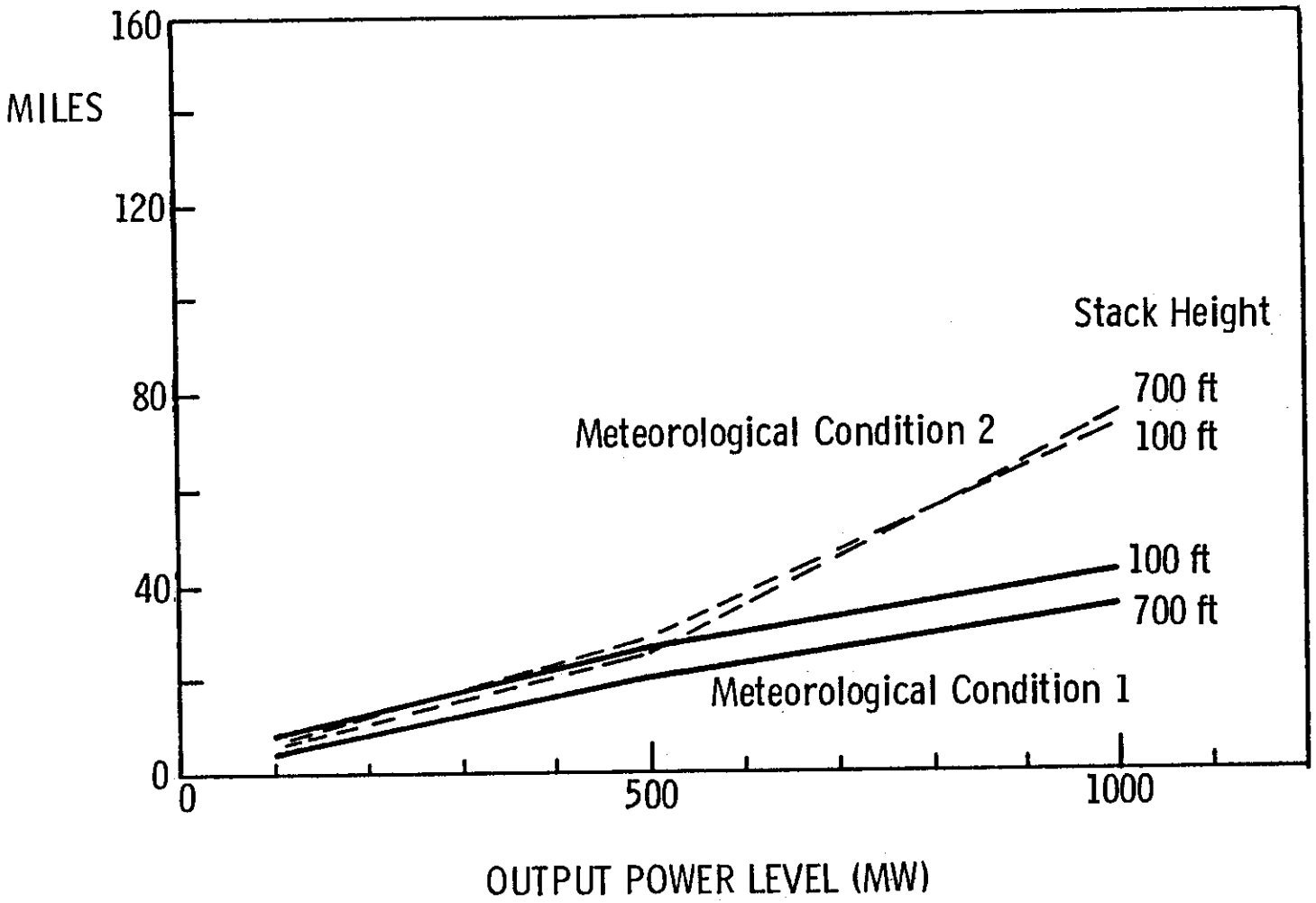

Figure II-22. Distance to ground-level concentrations of 5 $\mu g/m^3$ SO_2 (Class I area increment) 1% sulfur coal, 80% efficiency scrubber $\Delta T = 90°$ C

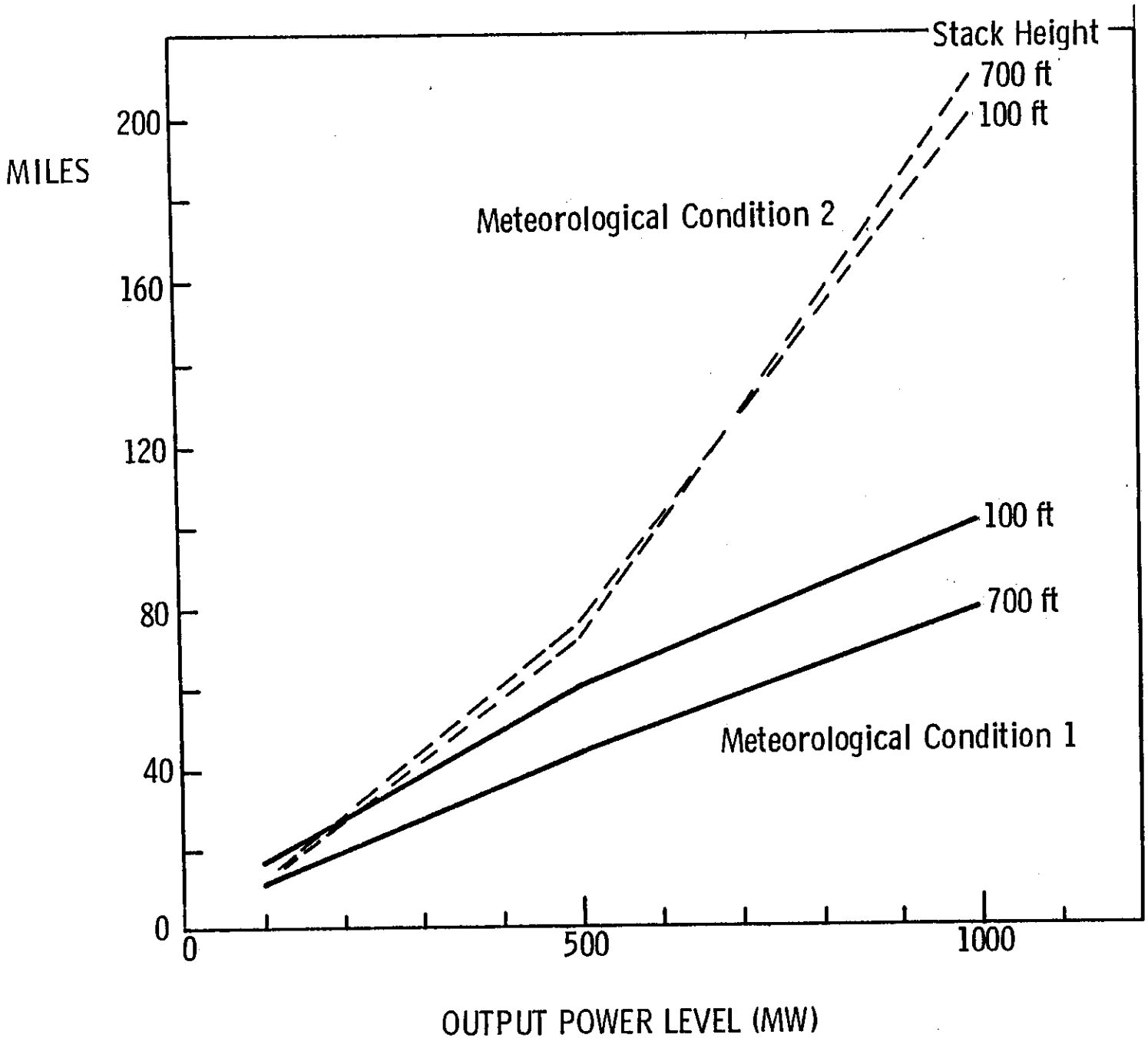

Figure II-23. Distance to ground-level concentration of 5 $\mu g/m^3$ SO_2 (Class I area increment) 2% sulfur coal, 80% efficiency scrubber ΔT = 90°C

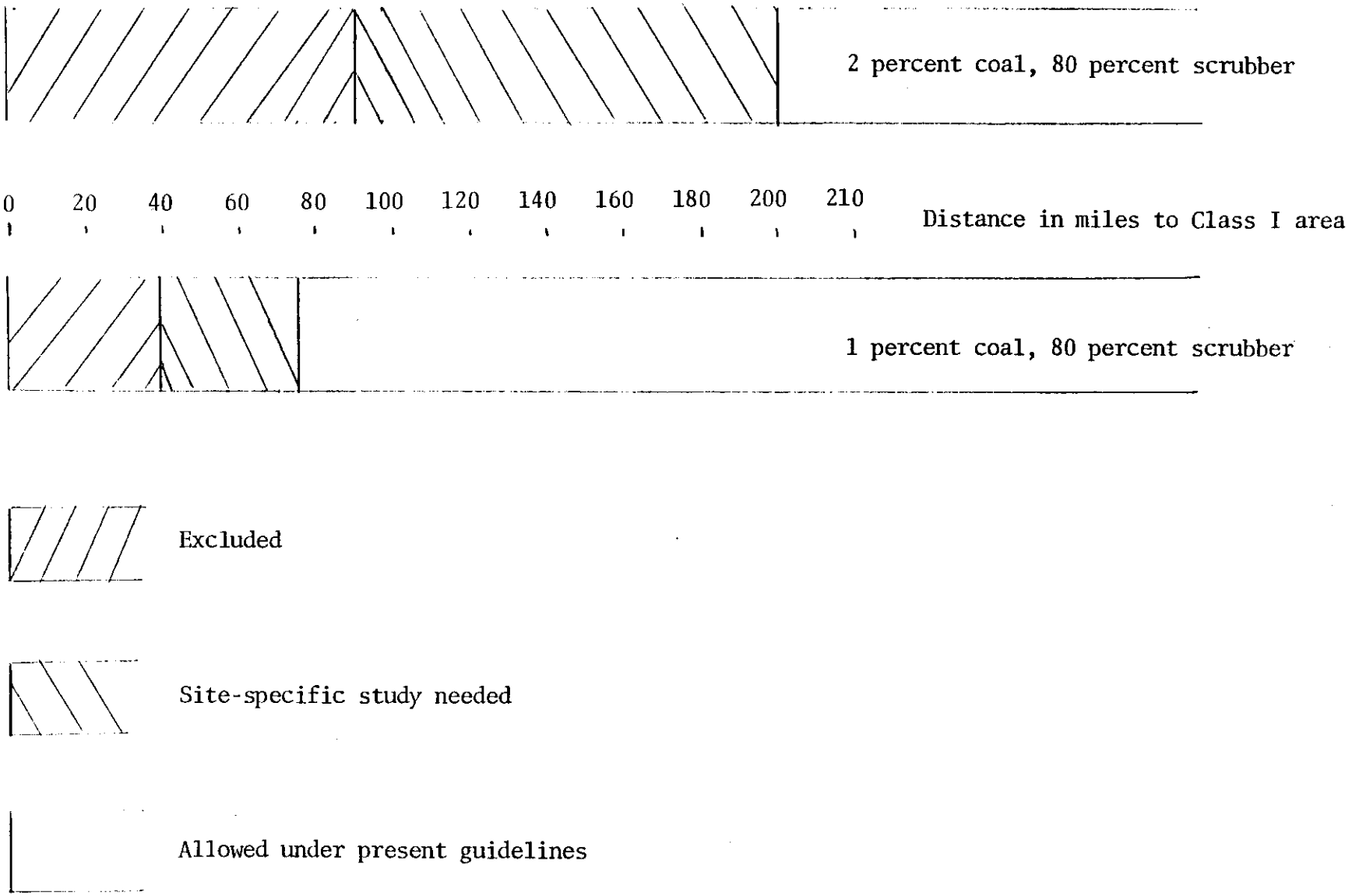

Figure II-24. Siting Restriction for a 1000 MW coal-fired plant with a 500 ft stack relative to a Class I area.

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