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OIL SHALE AIR POLLUTION CONTROL

by

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ABSTRACT

This study evaluates the air pollution potential of emissions of particulates, sulfur dioxide, oxides of nitrogen, and hydrocarbons from the anticipated development of an oil shale industry. The analysis is based primarily on the published description of a TOSCO II retorting process as planned for commercial use by the Colony Development Operation. The technology, processes, plans, projections, and environmental impacts of oil shale development are reviewed. The results of dispersion model calculations of concentrations of pollutants in ambient air near oil shale plants employing TOSCO II and in situ processes are presented. These calculations for the TOSCO II plant assume that best available controls are applied to the process planned by Colony. Requirements for additional control are estimated by comparing calculated ambient air quality with standards. Options for supplying the additional control indicated for particulates and sulfur dioxide are identified.

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UNITS OF MEASURE

Conversion of U.S. units of measure to the metric system is now proceeding rapidly. Several agencies of state and federal governments now call for the use of metric units (e.g., the geothermal group of the California Division of Oil and Gas). The Environmental Protection Agency has required the use of metric units in this report.

SRI has, therefore, employed the International System of Units (SI), which is based upon the meter, kilogram, and second as the basic measures of length, mass, and time. Within this system, energy units are derived combinations of the basic units. The preferred unit for energy is the joule.

During the period of changeover to metric units, a certain amount of confusion must be expected--especially since energy is measured in such various units as Btu, joules, kilocalories, barrels of oil equivalent, kilowatt hours, therms, and so on. To minimize this confusion, SRI has expressed energies in joules or multiples of the watt hour and made sparing use of hybrid units, such as metric ton and the engineering units of the English system. The prefixes kilo, mega, and tera are sometimes used in accordance with standard SI practice. The following listing summarizes the most common conversion factors that readers may want to have available while reading this report. A list at the end of this section presents a few conversion factors of special importance in discussion of oil production and air pollution.

Further information on the International System of Units can be found in Special Publication 330, National Bureau of Standards, Department of Commerce.

Energy

1 Btu = 1.055×10^{3} joule (J)

1 Btu = 2.929×10^{-4} kilowatt hour (kWh)

1 kWh = 3.600×10^{6} joule (J)

1 kcal = 4.186×10^{3} joule (J)

Length

1 inch = 2.540×10^{-2} meter (m)

1 inch = 2.54 centimeter (cm)

1 foot = 0.3048 meter (m)

1 yard = 0.9144 meter (m)

1 mile = 1.609 kilometer (km)

Mass

1 pound = 0.4536 kilogram (kg)

1 ton (short) = 9.072×10^{2} kilogram (kg)

1 tonne = 1 metric ton (MT)

1 metric ton = 10^{3} kilogram (kg)

Area

1 acre = 0.407 hectare (ha)

1 acre = 4.047×10^{3} square meter (m^2)

1 square foot = 9.290×10^{-2} square meter (m^2)

1 square mile = 2.590×10^{6} square meter (m^2)

1 square mile = 2.59 square kilometer [$(km)^2$]

Volume

1 cubic foot = 2.832×10^{-2} cubic meter (m^3)

1 gallon = 3.785×10^{-3} cubic meter (m^3)

1 barrel (oil) = 0.1590 cubic meter (m^3)

Pressure

1 pound per square inch = 6.895×10^3 Pascal (Pa)

1 bar = 10^5 Pascal (Pa)

1 atmosphere = 1.013×10^5 Pascal (Pa)

1 Pascal = 1.0 newton/m^2

Equivalents

Factor	Prefix	Symbol
10^{-3}	milli	m
10^{-2}	centi	c
10^{-1}	deci	d
10^{1}	deka	da
10^{2}	hecto	h
10^{3}	kilo	k
10^{6}	mega	M
10^{9}	giga	G
10^{12}	tera	T

Conversions especially important in this report:

- Oil--1 m^3 = 6.3 barrels
- Particulate loadings--1 mg/m^3 = 0.00043 grains/ft^3
- Volumetric flow rates--1 m^3/sec = 2120 ft^3/min
- Emission factors--1 kg/GJ = 2.3 lb/million Btu

ACKNOWLEDGMENTS

This study was organized within the Operations Evaluation Department of SRI. The project leader was Evan E. Hughes. Supervision was exercised by Edward M. Dickson, Manager of the Resources Program of the department. Ronald K. White had major responsibility in the study as the author of the sections of the report dealing with air pollution control technology.

Robert G. Murray of the Chemical Engineering Group contributed the sections on oil shale technology and the plans of the industry. He also provided other members of the project team with insights and information on oil shale processes and plans.

Carmen V. Fojo of the Energy Technology Department reviewed various sources of information on the environmental effects of oil shale development and organized a summary of such effects for this report.

Patricia A. Buder of the Atmospheric Sciences Laboratory carried out the dispersion modeling of air pollution from oil shale production and wrote the section of the report discussing such results. Support in this work was provided by Francis L. Ludwig. Walter F. Dabberdt supervised this aspect of the project.

Elizabeth D. Gill of the Literature Research staff of the SRI library provided support for the project. This work was supervised by Ardra F. Fitzgerald.

I CONCLUSIONS

During the next decade a commercial oil shale industry could develop in western Colorado and eastern Utah and grow to a production capacity of 80;000 m^3/day (500,000 barrels/day) of oil. The TOSCO II retorting process is likely to be used in most of the first generation plants.

Colony Development Operation has published a detailed environmental impact analysis of a proposed TOSCO II oil shale plant. A number of air pollution control systems are included in the proposed plant, but the level of control is less than that attainable with the best available control technology.

Application of best available control technology would result in improved removal of particulates by cyclones, baghouses, and wet scrubbers, thereby reducing overall particulate emissions to about a third of the level specified in the Colony publication.

More extensive treating of fuels burned in the plant would constitute the application of best available control to the emissions of SO_2 and NO_x. This would reduce SO_2 emissions by about 15 percent and NO_x emissions by about 50 percent.

Atmospheric dispersion modeling of emissions from a 16,000 m^3/day (100,000 B/D) TOSCO II plant having best available controls suggests that such a plant can avoid violations of federal primary ambient air quality standards for particulates, sulfur dioxide (SO_2), hydrocarbons (HC), and oxides of nitrogen (NO_x).

From the same modeling, requirements for controls beyond those considered to be the best available have been estimated by application of more strict ambient air quality standards that can reasonably be expected to apply in the oil shale region. The standards most likely to apply are those for regions that the state designates as Class II under the proposed federal standards to prevent significant deterioration of ambient air quality in unpolluted areas. For particulates and sulfur dioxide, Class II standards lead to the following requirements for additional control:

- Particulates: 85 percent additional control required to meet the 24-hour average Class II standard.
- SO_2: 72 percent additional control required to meet the one-year average Class II standard.

No additional control requirements are indicated for hydrocarbons and oxides of nitrogen. This conclusion is based on comparison of calculated concentrations with the federal primary standards for HC and NO_2. Photochemical oxidant formation was not included in the dispersion model use, nor were comparisons made with ambient air quality standards for oxidant.

II RECOMMENDATIONS

Additional efforts are needed to assure that the development of an oil shale industry does not produce significant degradation of air quality through emissions of particulates, sulfur dioxide, and oxides of nitrogen. For each of these three pollutants, the problem and suggested steps toward a solution are specified below:

- Particulates: Appreciable control beyond best available is required to meet air quality standards applicable in Class II regions under proposed federal "non-degradation" standards. The potential contribution of higher stacks and more perfectly maintained baghouses to the attainment of this additional control should be determined. The potential for increased control should be specified on a unit operation basis, guided by additional dispersion modeling to determine the relative contributions of various units to the excessive concentration of particulates.

- *Sulfur Dioxide (SO_2):* These emissions from combustion sources within the oil shale plant must be controlled to a significant degree beyond the emission levels considered best available according to new source performance standards for liquid fossil fuel fired boilers. The additional control is necessary in order to meet the Class II "non-degradation" standards expected to apply to ambient air quality in the oil shale region. Flue gas desulfurization and additional hydrotreating of liquid fuels burned in the plant are actions that could be taken to meet the requirement for additional control. No steps to develop new control technology, other than continued efforts to improve flue gas desulfurization, are recommended for SO_2 emissions from oil shale plants.

- Oxides of Nitrogen (NO_x): No requirement for additional control has been established by comparison of dispersion modeling of oil shale plant emissions with ambient air quality standards. However, because the achievement of emissions consistent with best available control are likely to require a much lower nitrogen content in the fuel, some investigation of the feasibility of much more extensive hydrotreating should be carried out. This has significance beyond the oil shale plant, because the product oil, with its high nitrogen content, is a candidate for sale as a fuel oil rather than a refinery feedstock.

Some recommendations for further research and development are more general than those classified by pollutant type above. These are:

- Analysis of the tradeoffs between taller stacks and increased cleanup of emission or process streams should be made for the case of oil shale plants.
- Sensitivity analyses of the dispersion modeling and the resulting control requirements should be carried out.
- Ambient air quality in a region occupied by a number of plants should be made the basis of a control requirement determination; the sensitivity of the result to various strategies for incorporating regional and multiplant considerations should be determined and evaluated.
- Other oil shale production processes, differing from TOSCO II primarily in the retorting stage, should be analyzed to the extent practical in the light of available information, using the present analysis as a reference case.

III INTRODUCTION

This is a report on Phase II of an SRI project in support of energy research and development planning in the Office of Research and Development of the U.S. Environmental Protection Agency. Phase I of this effort consisted of a survey of the environmental effects of some new energy technologies and an identification of some research and development needs directed toward environmental quality control. An account of this previous work is presented in the SRI report, "Control of Environmental Impacts from Advanced Energy Sources," published as EPA-600/2-74-002, dated March 1974. Four advanced energy sources were emphasized in that report: solar, geothermal, oil shale, and solid wastes.

The present report emphasizes the air pollution control problems expected from first generation commercial plants for producing oil from the shale of the Green River Formation found in Colorado, Utah, and Wyoming. The main conclusions of the study have been summarized in the two preceding sections (Sections I and II). The following sections (Sections IV through IX) present the specific analyses that support these conclusions. The organization of the following sections outlines SRI's analysis:

Section IV reviews the technology and processes for the production of shale oil. It builds on the discussion in the previous report (see Section IV-D and Appendix C of "Control of Environmental Impacts from Advanced Energy Sources") and focuses on the technology that is nearest to commercial realization, namely the TOSCO II retorting system. In-situ retorting is also reviewed.

Section V presents the announced plans of the companies and organizations of companies that may build plants for the production of oil from shale during the next decade. It also discusses projections of growth of the oil shale industry by three different sources.

Section VI reviews the general environmental impacts of oil shale development as presented in the previous report and in some other recent sources. The review covers air, water, and land impacts.

Section VII begins the specific task of quantitatively determining the air pollution control requirements of the oil shale industry by presenting the results of some atmospheric dispersion modeling to determine the concentrations of pollutants in ambient air arising from emissions from proposed oil shale production facilities. The facilities are assumed to employ the best available air pollution control technology. Hence, this modeling is based on a plant with the emission properties specified in a later section (Section IX) of the report. Control requirements beyond "best available control" are estimated by comparison of the calculated air pollutant concentrations with various possible ambient air quality standards. While the focus is on TOSCO II retorting, some results are also presented for an in-situ retorting facility.

Section VIII summarizes the control requirements determined by the air quality modeling approach of Section VII. The control required to bring TOSCO II combustion operations into compliance with new source performance standards for emissions from fossil fuel fired boilers is briefly discussed. The conclusions as to what constitute reasonable requirements for control beyond the best available are presented in this section.

Section IX describes the air pollution control planned for the TOSCO II retort and oil production complex proposed by Colony Development Operation. Tables and figures are used to describe the production processes and their associated controls. Tables describe unit operations within the total oil production system and present the uncontrolled emissions, the results of planned controls, and the results of best available control. Here "best available" is quantified and specifically defined for each unit operation.

IV OIL SHALE TECHNOLOGY AND PROCESSES

A. Introduction

As the oil shale situation in the western United States slowly emerges from pilot plant to commercial production, the problems change in character. Specific technical problems pertaining to retorting assume less importance and the problems related to industry requirements assume greater importance. The necessity for an organization to solve a wide range of practical problems in order to get a plant on stream tends to make it favor proven technology and high reliability over more advanced, potentially more efficient, but untested solutions. Thus, while there are several different types of retorts at various levels of development, only two or three of the most advanced designs are likely to be placed in commercial production.

In addition to a large reserve of adequate quality shale, a sufficient supply of water is an essential prerequisite for a shale enterprise. Converting oil shale to a salable crude oil and by-products will also require the following operations:

- Mining of the shale and transporting it to the retorts.
- Separation of valuable hydrocarbons from the mineral residue.
- Disposal of all residues, effluents and emissions in an acceptable manner.
- Conversion of the crude shale oil to a transportable product.
- Transport of the product and by-products to market.
- Disposal of valueless by-products.

Economies of scale in most of the process steps required in a commercial shale enterprise are of such importance that a small-sized operation is economically unattractive. As a result, the industry cannot start small and make its early mistakes on a small size. This requirement to be big limits entry into the industry to groups with relatively large capital resources.

B. Underground Mining and Above-Ground Retorting

The classical method of obtaining and retorting shale is underground mining followed by above-ground retorting. It has been practiced in many places around the world for over 100 years. The methods developed for the U.S. shales differ due to the use of modern mining technology and due to the special characteristics of the shale. Mining, transporting, and crushing operations for shale are quite similar to those used in several rock and mineral industries. The principal difference lies in the magnitude of the proposed operations.

Retorting, on the other hand, is not quite like any existing industry operation. It resembles the production of coke from coal, except that the solid produced (spent shale) is not a valuable product, but is a liability to be disposed of. It resembles metallurgical ore roasting, except that the product is combustible. These differences in physical characteristics and product values place severe restrictions on what is economically possible in retort design.

Retorting processes can be placed into four classes according to the method of transferring heat to the shale.

> Class I, External Combustion--Heat is transferred to the shale through a wall. The simplest form of this retort is a Fischer assay device for measuring the amount of oil that may be recovered from a sample of shale. The shale is placed in a closed container and heated by means of a fire outside the retort. The retorted gas and liquids are uncontaminated by

air and the sulfur compounds are in a reduced state, e.g., hydrogen sulfide rather than sulfur dioxide. Because the heat source is external to the retort, any fuel may be used. The emissions from the heat source will depend upon the fuel used. This type of retort is expensive in terms of capital and operating costs per unit of produced oil. It is not likely to be competitive with other types of retorts.

Class II, Internal Combustion--Heat is transferred to the shale from hot gases generated in the retort by the combustion of some of the carbon and hydrogen present in the shale. Examples include the Paraho* retort, the N-T-U retort, and the gas combustion and Laramie simulated in situ retorts of the Bureau of Mines. A controlled amount of air and recycle gas is introduced into the retort and a mixture of product oil and low heat content (low Btu) gas is recovered. The advantages of this system are low capital and operating costs per unit of shale input. Disadvantages are low recovery of the total energy in the shale and the production of a large quantity of flue gas containing about 3 MJ/m^3 (80 Btu/scf) energy content. For example a typical gas combustion retort plant producing 16,000 m^3 (100,000 barrels) per day of shale oil would also produce about 23 million cubic meters per day of low heat content gas. Sulfur contained in this gas would be on the order of 200 tonnes per day.

Class III, Hot Fluid--Heat is transferred to the shale by passing hot gas that has been heated in an external furnace through the shale bed. The Petrosix, the Union-SGR, and one variation of the Paraho are examples of this type of retort. By circulating high heat content (high Btu) product gas through the retort, the problems of the Class II retort are eliminated. The gas has much more value and sulfur compounds can be removed by amine scrubbing. However, the capital cost of the equipment required to heat the recirculating gas makes this an expensive type of retort. Additional problems are caused by the tendency of the external gas heater to accumulate carbon deposits caused by oil mist in the gas.

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*The Paraho project is committed to developing two different retorts--I, a gas combustion type and II, a hot gas circulation type.

Class IV, Hot Solid--Heat is transferred by the introduction of hot solids into the retorting bed. The two best known examples of this class are the TOSCO II retort in which heat is transferred by ceramic balls and the Lurgi-Ruhrgas retort in which heat is transferred by recirculating hot shale ash. The principle of retorting is to combine raw shale with enough hot recycle solids to produce retorting temperatures in the mixture. This class of retort is fairly expensive, but does recover a high percent of the energy in the shale. The gas from the retort has a high heat content (high Btu) and sulfur compounds are in the reduced state.

As shown below in Table 4, most of the first generation commercial ventures plan to use the TOSCO II retort. This is the only retort that has been demonstrated in the configuration of the commercial facility. Union Oil Company plans to use their own retort system and will build a demonstration unit before proceeding with a commercial plant.

The group on the combined Utah a and b sites may use a Paraho type of retort if the Paraho demonstration is successful. Superior Oil Company has not announced the type of retort they plan to use. However, their process requires that the shale ash not be overheated as would occur in a gas combustion type of retort.

There is an interaction between the method of retorting and the sulfur dioxide emissions that has not yet been resolved. Class II retorts (gas combustion and Paraho I) produce a large quantity of low heating value (3.7 MJ/m^3 or 100 Btu/scf) gas as a by-product that may contain oxidized sulfur compounds. Class IV retorts (TOSCO II and Union-SGR) produce gaseous products that are not diluted with air; the gas has a high heating value (about 30 MJ/m^3) and the sulfur is in the reduced state. In general, it is much less expensive to remove sulfur compounds from high heating value gas.

Of the three retorts likely to reach commercial production, information in the public domain is available only for TOSCO II. Neither

Paraho nor Union have published sufficient details of their processes to allow calculation of off-gas composition. However, both Paraho and Union, or any other retort, could meet the sulfur dioxide and hydrocarbon emission restrictions presently applicable to new fossil-fueled power generation plants by using stack gas scrubbing. (It may be that such stack gas scrubbing would be so expensive as to make the retort uncompetitive with other types of retorts that do not require scrubbers.)

From the above line of reasoning we conclude that overall emissions from a conventional shale industry may be estimated using TOSCO II emission rates. Such estimates of emissions have been derived for a typical production facility based on TOSCO II retorting with subsequent upgrading of the crude shale oil to a low sulfur fuel oil by delayed coking and hydrogenation. This facility is described in the next section.

C. Shale Oil Production Module

The basic unit used in this study of a shale oil industry is a complete facility for mining oil shale, retorting the shale, disposing of the spent shale, and upgrading the crude shale oil to 16,000 m^3/day (100,000 barrels per day) of low sulfur fuel oil.* A complete description of these operations as they are proposed by the Colony group may be obtained in Reference 1.† The information obtained from this reference was scaled to our 16,000 m^3/day (100,000 barrels per day) unit size and the resulting plant flows are shown in Figure 1 and Table 1. The block flow diagram, Figure 1, shows the major processing units, the major process flow streams, and all plant inputs and output streams. Table 1 lists the

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*The proposed low sulfur fuel oil is about 0.3 percent sulfur, somewhat higher than some previous plans[1] for a synthetic crude oil of less than 0.1 percent sulfur content by weight.

†References are listed at end of section.

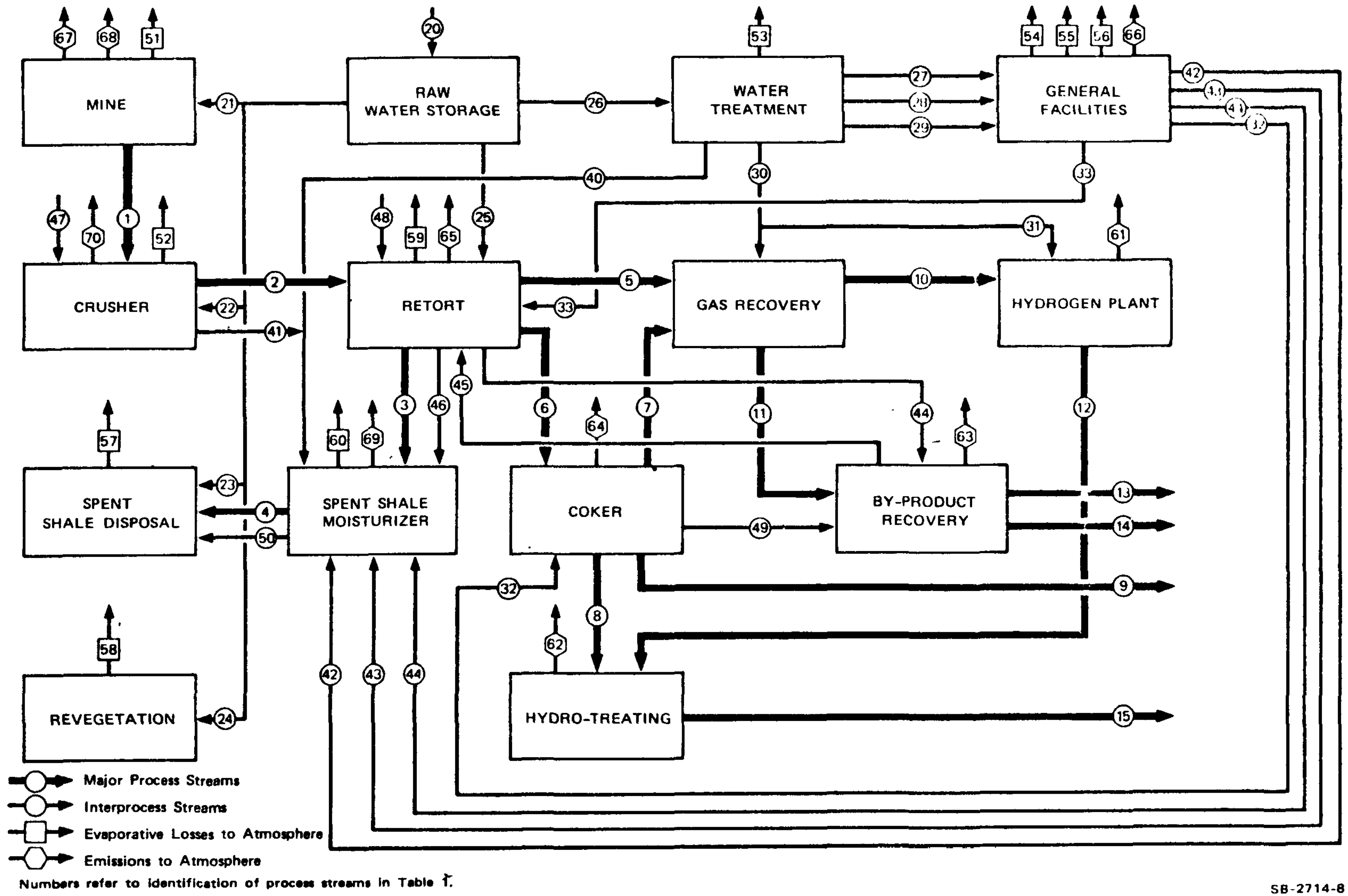


FIGURE 1 PROCESSES, STREAMS, AND EMISSIONS FOR PRODUCTION OF OIL FROM SHALE

Table 1

IDENTIFICATION OF STREAMS SHOWN IN FIGURE 1*

Major Process Streams

Line No	Material Quantity	Flow Rate m^3/hr	Remarks
1	Shale		
2	Crushed shale		Includes 75 m^3/hr gpm surface moisture
3	Spent shale		
4	Moisturized shale		
5	Retort gas		
6	Raw shale oil		
7	Coker gas		
8	Gas oil		
9	Coke		
10	Clean gas		
11	Sour water	82	
12	Hydrogen		
13	Sulfur		
14	Ammonia		
15	Oil product		

Major Water Streams

Line No	Material Quantity	Flow Rate m^3/hr	Remarks
20	Raw water	2500	Total raw water to plant
21	Raw water	160	Mine dust suppression
22	Raw water	190	Crusher dust suppression
23	Raw water	115	Disposal area dust control
24	Raw water	320	Revegetation irrigation
25	Raw water	370	Retort dust scrubbers
26	Raw water	1390	To water treatment plant
27	Treated water	45	Fire/service/drinking
28	Treated water	590	Cooling tower makeup
29	Treated water	590	Boiler feed water
30	Treated water	80	Wash water
31	Treated water		Hydrogen plant
32	Steam	15	To coker
33	Steam	100	

High Mineral Content Water

Line No	Material Quantity	Flow Rate m^3/hr	Remarks
40	Saline water	45	Ion exchange regeneration
41	High particulates	50	Crusher dust slurry
42	High minerals	140	Cooling tower blowdown
43	High minerals	60	Boiler blowdown
44	Foul water	170	From retorts
45	Low organic content	280	Stripped sour water
46	High minerals	550	Combined waste streams
47	Surface water	75	Natural and added
48	Created water	200	Combustion and retorting
49	Foul water	15	From coker
50	High minerals	730	Combined with stream 4
51	Evaporation loss	160	Mine dust control
52	Evaporation loss	100	Crusher dust control
53	Evaporation loss	10	Water treating
54	Evaporation loss	450	Cooling tower
55	Sanitary sewage	70	General facilities
56	Steam losses	420	
57	Evaporation loss	115	Disposal dust control
58	Transpiration and to ground	320	Irrigation
59	Scrubber losses	300	
60	Moisturizer evaporation	230	

Atmospheric Emission Streams †

Line No	Material Quantity	Flow Rate	Remarks
61	Flue gas	320	Hydrogen plant fuel
62	Flue gas	75	Hydrotreater heater
63	Sulfur recovery tail gas	30	By-product recovery
64	Flue gas	45	Coker charge heater
65	Retort flue gas	1150	Ball heater
66	Flue gas	240	Plant boilers
67	Diesel exhaust		Mine ventilation
68	Explosive exhausts		Mine ventilation
69	Organic vapors		Residual from stripped water
70	Air containing particulates	600	Crusher ventilation
71	Flue gas		Flare

*16,000 m^3/day (100,000 barrel/day) TOSCO II oil shale plant.

†Flow rates for atmospheric emission streams are in m^3/sec, rather than m^3/hr.

quantity and type of water flow streams and atmospheric emissions. Table 2 lists the physical characteristics of the emission streams and Figure 2 is a diagram showing typical locations of the stacks in a shale oil facility.

D. In Situ Retorting

The previous sections discussed conventional oil shale technology and some plans of groups who intend to enter the industry. This section considers in situ extraction of oil from shale and its potential for augmenting the conventional approach. In situ technology is believed to be several years behind conventional above-ground retorting and there have been no publicly announced plans for a commercial in situ venture. Nevertheless, it must be considered a potential method to produce oil after about 1980 because there may be lower capital and operating costs as well as less water consumption.

Methods proposed for in situ oil recovery include hot fluid circulation, solvent extraction, and underground combustion. Several procedures have been proposed for preparing the shale deposit prior to the retorting operation such as rubblizing, fracturing, leaching out soluble inorganic components, or draining water from the naturally porous areas. The method most apt to be developed to commercial practice consists of preparing underground retorting chambers filled with shale rubble using conventional mining methods and then heating the shale by combustion starting at the top of the column. This procedure is similar to that used in fixed bed retorts such as the N-T-U and the simulated in situ retort located at Laramie Energy Center.[2] Of course the in situ retorts must be on a much larger scale to be economic.

Garrett Research Division of Occidental Petroleum Corporation has developed and field tested this method of retorting.[3] The first field test contained about 3,500 tonnes of shale rubble, and 190 m^3

Table 2

STACK PARAMETERS AND EMISSION RATES FOR A 16,000 m^3/D (100,000 B/D) TOSCO II PLANT WITH EMISSIONS CONTROLLED*

Location†	Line No.‡	Description of Unit	Flow Rate§ (All Stacks) m^3/sec	Temp. °C	Number of Stacks	Stack Height m	Stack Diameter m	Gas Exit Velocity m/sec	Emissions (Total for all Stacks) Particulates g/sec	SO_2 g/sec	HC g/sec	NO_x g/sec
1	61	Hydrogen Unit	317	260	2	30.5	3.0	21.7	2.7	81.0	-	135.4
2	62	Naphtha Hydrogenation	7	427	1	24.4	0.9	10.8	0.05	1.3	-	2.3
3	62	Gas Oil Hydrogenation: Feed Heater	36	427	2	24.4	1.8	6.8	0.23	1.8	-	10.8
4	62	Gas Oil Hydrogenation: Fired Reboiler	31	427	1	24.4	2.1	8.6	0.20	1.5	-	9.1
5	63	Sulfur Plant	30	38	1	76.2	1.5	16.6	-	16.1	-	-
6	64	Delayed Coker	45	260	1	24.4	1.8	17.2	0,39	11.3	-	18.9
7	66	Steam Superheater--Ball Stack	244	54	12	76.2	1.8	7.8	11.1	5.3	-	33.6
8	65	Raw Shale Preheat	1160	54	12	76.2	4.0	7.8	52.8	257.0	75.6	297.0
9	69	Processed Shale Moisturizer	119	91	12	12.2	1.2	8.4	5.6	-	-	-
10	70	Primary Crusher	236	16	2	15.2	2.4	25.2	10.8	-	-	-
11	70	Final Crusher	283	16	20	15.2	1.2	12.1	13.1	-	-	-
12	70	Fine Ore Storage	76	16	2	15.2	1.5	20.6	3.3	-	-	-
13	66	Utility Boilers	49	260	4	15.2	1.2	10.8	2.5	18.6	-	6.9

*Assumed best available control as specified in Section IX of this report.

†Location refers to Figure 2.

‡Line number refers to Figure 1 and Table 1.

§To convert to ACFM multiply by 2120.

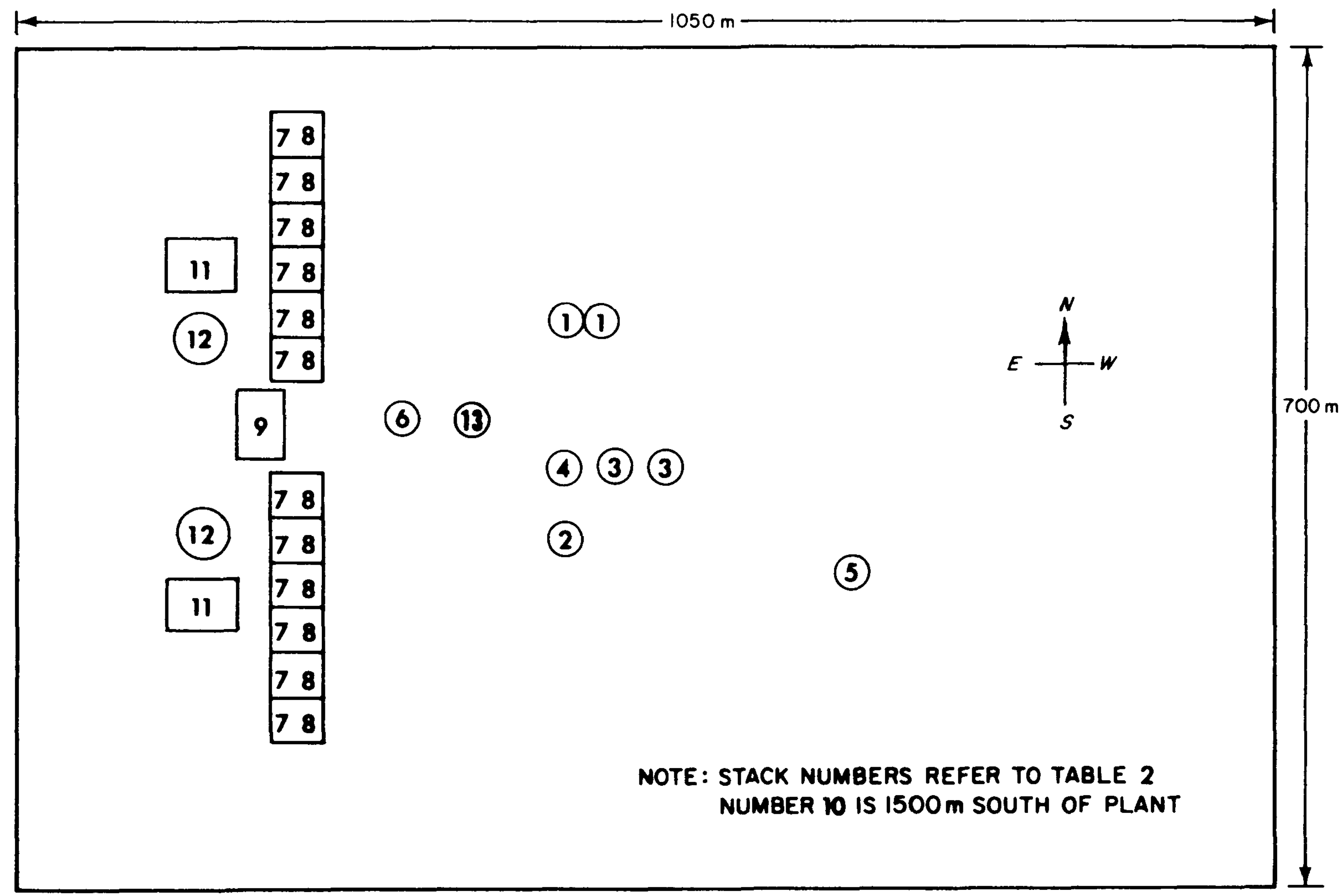
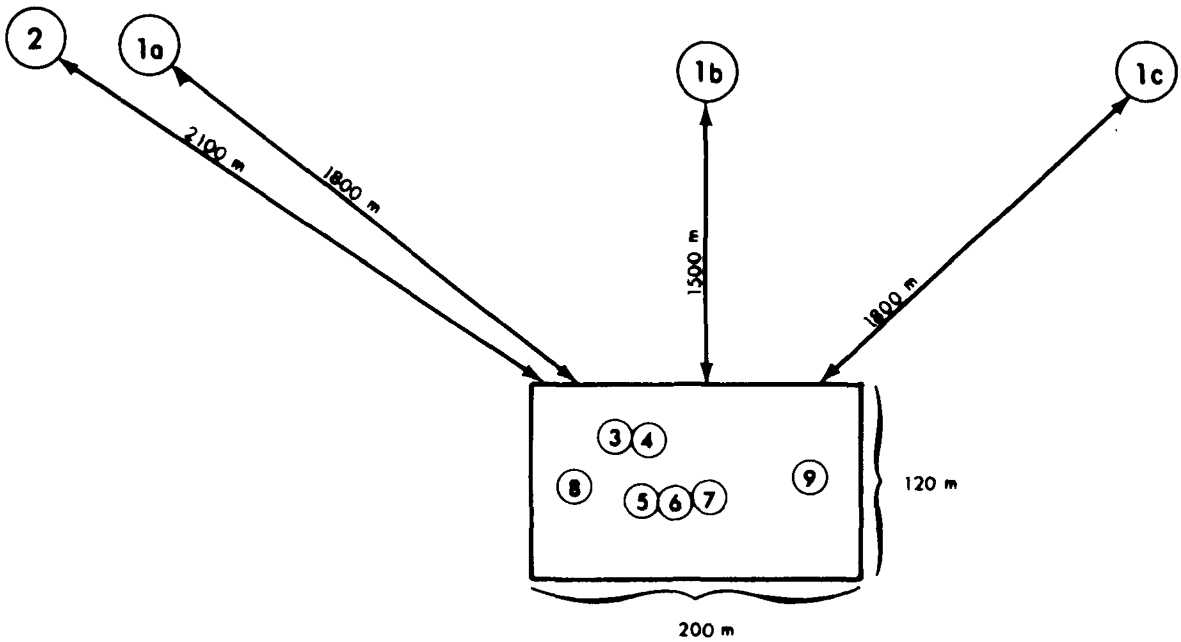


FIGURE 2 TOSCO II PLANT CONFIGURATION

(1,200 barrels) of oil were recovered. At present they are preparing to test a retort 75 m (250 feet) in height and 30 m (100 feet) square. These dimensions are in the range of a commercial development of a shale deposit. Larger retort dimensions, if possible, would result in lower overall costs as well as a greater recovery of the oil (kerogen) in-place in the shale.

Although the mining and retorting costs for in situ recovery are estimated to be lower than for conventional shale oil retorting, there are a great many unknown cost factors that must be established before a commercial venture can be established. Retort and facility design will be dependent upon the geology and hydrology of the particular shale deposit to be developed. Aquifers above or below the shale bed will require water control or extensive dewatering. Fractures or porosity in the shale must be determined and taken into consideration in the retort development plan. A sequence of retort construction and operation must be designed to allow use of mine adits and drifts for shale transport and recycle gas flow under conditions of complete mine safety. These are just a few examples of the difference between a successful field test of one retort and a commercial development that could require the integrated operation of thousands of retorts over the life of a venture. (Figure 3 illustrates this procedure with successive in situ retorts at 1a, 1b, and 1c.)

Table 3 and Figure 3 characterize possible atmospheric emission streams from an in situ retorting plant. The major stream consists of a large quantity of off-gas that must be disposed of by venting to the atmosphere during retort operation. The retort off-gas composition will vary somewhat in accordance with several retorting parameters but will probably contain about 1.8 MJ/m^3 (50 Btu/scf) of combustible hydrocarbons and carbon monoxide as well as some sulfur compounds. The heating value of this gas may be sufficient to allow recovery of some energy by burning the gas in a turbine or steam generating system. In any event, the



NOTE: STACK NUMBERS REFER TO TABLE 3
NOT TO SCALE

FIGURE 3 IN SITU PLANT CONFIGURATION

Table 3

STACK PARAMETERS AND EMISSION RATES FOR A 16,000 m^3/day (100,000 B/D) IN SITU PLANT

Stack Location*	Description of Unit	Flow Rate† (All Stacks) m^3/sec	Temperature °C	Number of Stacks	Stack Height m	Stack Diameter m	Gas Exit Velocity m/sec	Emissions (Total for all Stacks) Particulates g/sec	SO_2 g/sec	HC g/sec	NO_2 g/sec
1	Incinerator Off Gas	1260	93	2	30.5	9.1	9.6	63.0	1260.0	126.0	37.8
2	Shale Transport	24	16	1	15.2	1.5	12.9	6.3	-	-	-
3	Hydrogen Plant	316	260	2	30.5	3.0	21.7	2.8	80.6	-	134.8
4	Hydrogen Plant	94	82	1	36.6	2.1	26.4	-	-	-	-
5	Hydrotreater	7	427	1	24.4	0.9	10.8	0.1	1.3	-	2.3
6	Hydrotreater	36	427	2	24.4	1.8	6.8	0.2	1.8	-	10.8
7	Hydrotreater	31	427	1	24.4	2.1	8.6	0.3	1.5	-	8.8
8	Coker Charge Heater	45	260	1	24.4	1.8	17.2	0.4	11.5	-	18.9
9	Claus Tail Gas	30	38	1	76.2	1.5	16.6	-	16.1	-	-

*Location refers to Figure 3.

†To convert to ACFM multiply by 2120.

carbon monoxide and hydrocarbons will be removed before venting and the sulfur compounds converted to sulfur dioxide. It is estimated that a 16,000 m^3/day (100,000 barrels per day) in situ operation would produce 1300 m^3/sec (2,670,000 ACFM) of effluent gas from an incinerator at a temperature of 95°C (200°F). This effluent stream would contain about 440 kg/hr (16 lb/min) of hydrocarbons and about 4400 kg/hr (160 lb/min) of sulfur dioxide. This is roughly equivalent to the quantity of stack gas emitted from a 1000 MW oil-fired electric generating plant, burning 5500 m^3 (35,000 barrels) per day of 1 percent sulfur residual fuel oil.

Another class of important environmental questions center around the large quantities of burned shale that will be left underground indefinitely. Shale ash disposal will probably not be as great a program for in situ operations as it will be for surface retorting. The major problem in both cases will be to prevent soluble minerals from entering the ground water or the Colorado River.

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3. R. D. Ridley, "In Situ Processing of Oil Shale," Quarterly of the Colorado School of Mines, Vol. 69, No. 2 (April 1974).

4. "The Economics of Commercial Shale Oil Production by the TOSCO II Process," by R. N. Hall and L. H. Yardumian, The 61st meeting of the American Institute of Chemical Engineers, Los Angeles, California (1968).

V PLANS AND PROJECTIONS FOR OIL SHALE DEVELOPMENT

The oil shale industry has been "just about to emerge" for the past 25 years. Predictions concerning the first commercial plant were made more than fifty years ago. However, the discovery of the vast East Texas oil fields in the early 1930s pushed shale out of the picture until recent Middle East problems brought it back to economic viability.

Even at present, not all of the economic and social forces in the United States can be said to be converging in favor of the development of a shale oil industry. In opposition to the high cost of petroleum and the desire for U.S. independence from foreign crude oil are the requirements for a nonpolluting shale industry, for little or no disturbance to the land containing the shale, and for competitive uses for the required water. The above factors, in addition to the fact that 80 percent of the shale reserves are publicly owned and subject to the ebb and flow of the political process, clearly make prediction of industry growth patterns hazardous.

Nevertheless, there is a considerable momentum built up in favor of the development of a shale industry; about 400 million dollars are now committed to that development. The forces for shale oil are stronger than the forces against shale oil. The question which cannot be answered at this time is: Can the theoretical techniques devised to create a nonpolluting shale industry be realized, in actual practice? If they can be realized, or suitable new solutions found, then there will be a long-term shale industry. If suitable solutions to the air and water problems cannot be found, then the American people will have to decide how they wish to proceed.

The present situation can be described by placing the economic groups who have a stake in the shale industry into two categories: (1) those corporations that have large amounts of money invested in shale and will lose much if they do not move quickly, and (2) those corporations that have acquired shale reserves over the years and can afford to wait. These are rather loose definitions and there are corporations who fit both categories at the same time. The important difference is that the first category has made a corporate decision to enter the shale industry.

The corporations in the first category are listed in Table 4. Also listed are six locations in Colorado and Utah where the probable first generation of shale oil ventures will be placed. The geographic locations are shown on the map in Figure 4. Tracts U-a and U-b are shown as one location since they are adjacent and will probably be developed jointly.

Table 4

SHALE OIL PLANT LOCATIONS AND TYPES

Location, as Shown in Figure 3	Group	Probable Retort	Probable Plant Size (m^3/day)*	Estimated Completion Date
C-a	Amoco-Gulf	TOSCO II	16,000	1981
C-b	ARCO-Ashland-Shell-TOSCO	TOSCO II	16,000	1982
U-a U-b	Phillips-Sun Phillips-Sun-Sohio	Paraho TOSCO II	16,000	1983
Colony	ARCO-Ashland-Shell-TOSCO	TOSCO II	8,000	1979†
Union	Union Oil of California	Union-SGR	16,000	1981
Superior	Superior Oil	Not known	8,000	1982

*16,000 m^3/day is a 100,000 barrel-per-day plant.

†In October 1974 Colony announced that the construction of this plant would be postponed indefinitely, thereby making the completion date later than 1979.

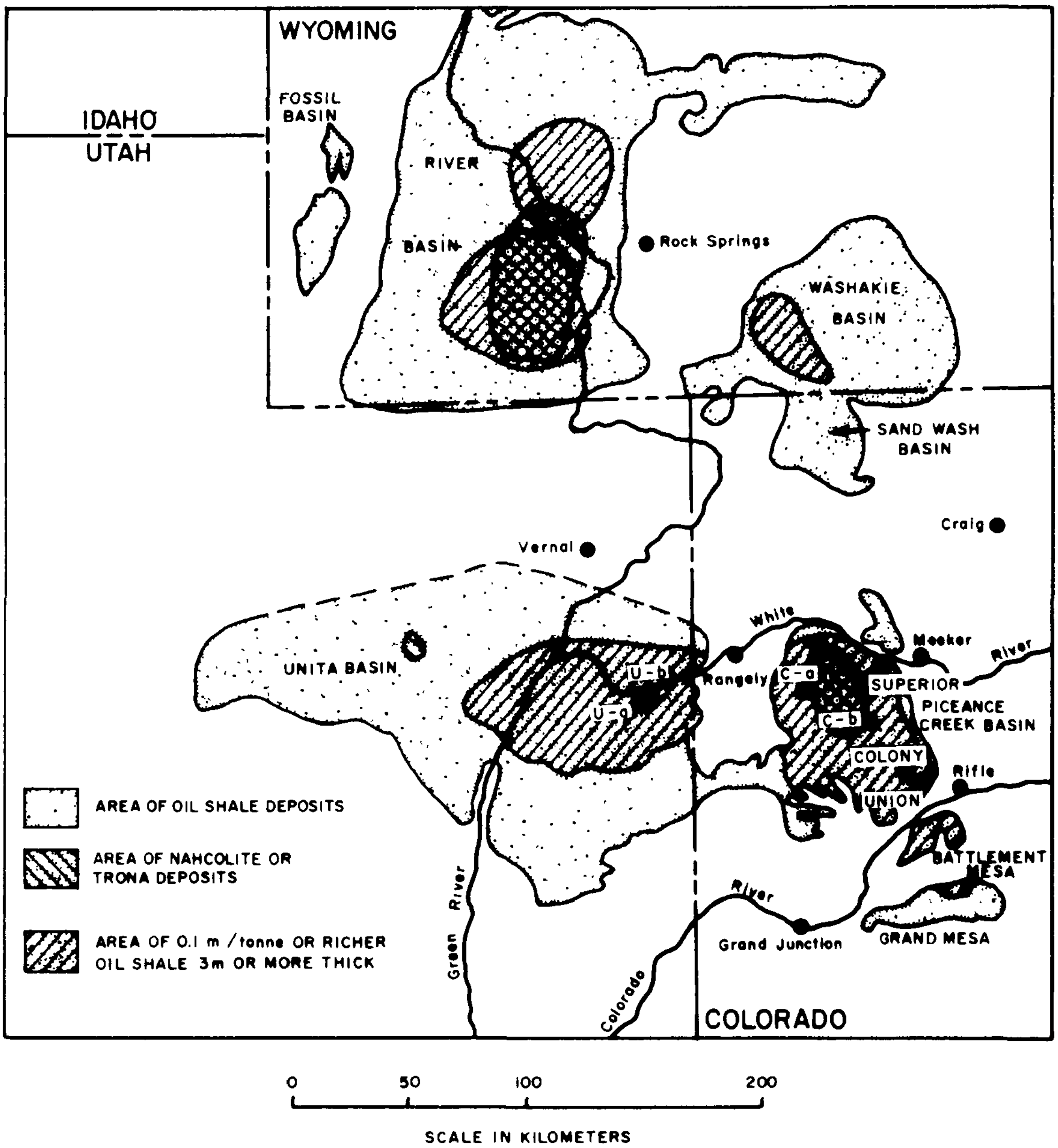

FIGURE 4 MAP OF OIL SHALE PLANT LOCATIONS

The second category of potential participants in a shale industry includes those corporations that own adequate shale reserves to support at least 8,000 m^3/day (50,000 barrels per day) of oil production, but have not announced any plans to develop the reserves. This group could enter the industry; and some of them might, if the overall economic conditions for shale development were made more favorable. This group includes: Cities Service, Exxon, Getty Oil Corp., Mobil Oil Corp., and Standard Oil of California.

A third category of companies can be defined as those companies who own low quality shale reserves or reserves that would require a large amount of "blocking up"* in order to obtain a compact mining plan.

A fourth category would include companies who have no shale reserves, but are developing processes that could be the basis of a joint venture. Occidental Petroleum and the Geokinetics group are in this category. Both have indicated a willingness to enter the shale industry by their unsuccessful bids on the federal shale leases. Such groups may also obtain shale reserves from Utah state lands at some future date.

From a historical point of view, the U.S. Bureau of Mines has long advocated an orderly growth of a domestic shale oil industry and has promoted this concept by supporting research and by the leasing program. The federal leasing program was originally conceived with this orderly growth in mind and is progressing along this course. More recently, however, programs for accelerated oil shale development have been suggested

*"Blocking up" occurs when an owner has a sufficient quantity of shale reserves, i.e., about 2,000 hectares (5,000 acres), but in land too widely dispersed to design an efficient mining plan. Such an owner hopes to exchange some remote land for federal land of equal value close to his principal holding. Superior Oil Co. is trying to do this for its land. Exxon would probably try to block up its holdings before putting up a plant.

as part of Project Independence. Early in the project very rapid oil shale development was contemplated. The original concept[1*] of complete independence from foreign oil supplies by 1980 has been abandoned as impossible--a more realistic goal combining a reduced growth rate for U.S. energy consumption and a longer transition period is now advocated.[2] Table 5 presents the three cases: (1) National Petroleum Council (NPC) prediction made in 1970,[3] (2) original Project Independence[1] and, (3) revised Project Independence,[2] as each relate to the growth of an oil shale industry. The required capital costs for the industry are also shown.

SRI predicts that the growth of a shale industry will be much closer to the 1970 NPC prediction than to the revised 1974 Independence numbers, up to 1985. The announced shale plants, as shown in Table 4, indicate a production rate of about 80,000 m^3/day (500,000 barrels per day) by 1984, allowing one year for a plant to reach full production. In addition to this amount of production from conventional mining and retorting, between 16,000 and 32,000 m^3/day (100,000 and 200,000 barrels per day) in situ production could be obtained by 1984. This total production of 80,000-112,000 m^3/day (500,000-700,000 barrels per day) represents the first generation shale industry.

Growth beyond the first generation will depend upon several factors that are not presently known. These are listed:

- The salinity of the Colorado River as a result of increased use of the pure upper source water, spent shale runoff, and saline water percolation.
- The cost of crude petroleum in the United States and on the world markets.
- The economic and social costs of shale oil production as perceived by the voters of the United States.

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*References are listed at end of section.

Table 5

REQUIRED OIL SHALE INDUSTRY GROWTH RATES
TO MEET SELECTED GOALS

	Year	1970 NPC Task Force*	1973 Original Independence†	1974 Revised Independence‡
Shale oil production Thousands of m^3/day§	1975	0	0	0
	1980	100	500	
	1983	200	1,500	
	1985	400		500
Total capital expenditures required for oil production**	1975	400	400	400
	1980	1,500	6,000	
	1983	3,400	22,000	
	1985	6,400		8,000

*Reference 3.

†Reference 1.

‡Reference 2.

§16,000 m^3/day is equivalent to 100,000 barrels per day.

**Millions of dollars, assuming 6% per year cost escalation.

If all of the above factors are positive in the sense that they will not limit the growth of the shale industry, the industry should continue to grow at a rate of 32,000 m^3/day (200,000 barrels per day) per year until limited by the available water supply. Thus, growth would level off at about 240,000 m^3/day (1,500,000 barrels per day) production by 1990. Beyond 1990, an average of 16,000 m^3/day (100,000 barrels per day) of new plant construction will be required each year to replace old facilities.

The physical characteristics of this predicted development (for the revised Project Independence) are discussed in "U.S. Energy Prospects: An Engineering Viewpoint" (Chapter 6).[2] Among the major efforts are:

- Bringing into production 250 million tonnes per year of shale mines.
- Laying, stabilizing, and restoring 17 square kilometers (5 square miles) of shale ash 13 m (40 feet) deep each year.
- Developing and conveying 100 million cubic meters (80,000 acre-feet) per year of new water supplies.

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2. "U.S. Energy Prospects: An Engineering Viewpoint," Task Force on Energy, National Academy of Engineering, Washington, D.C., Chapter 6 (1974).
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VI ENVIRONMENTAL EFFECTS OF OIL SHALE DEVELOPMENT

Discussion of the environmental effects of oil shale development tends to be controversial and could become especially significant. The controversy is strongest in Colorado, the region of the most promising oil shale resources, and is most concentrated in Denver, which is the center of both general population and that special segment of population of Federal, State, corporate, and environmentalist personalities involved in the controversy. The special significance of this discussion is its role in making the first assessment of environmental impacts of an industry before the industry exists as a commercial operation.

The environmental impacts themselves are unusually significant due to the physical and chemical properties of the oil shale. Oil shale is an alkaline rock containing a relatively small hydrocarbon fraction, the 10 to 15 percent by weight which is the kerogen that can be converted to a fuel. After extraction of the fuel, the vast majority of the mass of the shale remains as a waste material. This waste, known as spent shale, of crushed and retorted rock contains minerals that can be dissolved easily by rain or snowmelt and is therefore a potential source of increased salinity in the Colorado River.

Political issues in this case are tied directly to environmental impacts. The quantity and quality of water in the Colorado River have been the subjects of a number of political and legal arguments. The salinity of the Colorado has been the subject of a recent agreement between the United States and Mexico, thus bringing international political overtones into the environmental impact assessment of oil shale development. Some details are given below in the discussion of water quality.

This section of the report contains a summary of the environmental effects of oil shale development under the headings of land, air, water, and aesthetics. Two precautions should be stated here, before the specific summaries:

(1) The extent to which the different kinds of environmental impacts can be adequately quantified varies a good deal. Because this report is directed toward the air pollution and control aspects of the oil shale industry, most of the effort at quantification has been made in that area. These findings are presented in greater detail in subsequent sections of the report. In this section, quantitative estimates are made for land, water, and air impacts. Aesthetic impacts tend to defy quantification and no attempt is made here to quantify them.

(2) The actual environmental impacts of oil shale development will be determined by the type of processing that finally passes the economic and regulatory requirements. The form of technology that will prove satisfactory in these respects is not yet determined. Perhaps the most significant example of this uncertainty is the technology for in situ processing of oil shale. This technology is under active study and development. Its use would significantly change the environmental impacts. Water use, for example, will be considerably less with in situ processing.

A. Land Impacts

The amount of rock that must be excavated in order to yield one cubic meter of shale oil is staggering. Oil shale of 0.125 m^3/tonne (30 gal/ton) will require the mining of 3.8 m^3 oil shale per cubic meter of oil produced. This much shale will yield 5.2 m^3 of spent shale; the volume increases after crushing and retorting.

The land disturbance due to the mine, surface facilities, and disposal area has been estimated by three sources. The ARCO source estimates a disturbance of 12.1-12.3 ha per 10^6 cubic meters of oil produced.[1*] The Department of the Interior predicts 12.6-13.7 ha per million cubic meters of oil.[2] SRI has previously estimated the disturbance to be 12.5 ha per million cubic meters of oil.[3] The area most likely to be developed in the next 25 years will be about 2,100 km^2 in Colorado in the Piceance Creek Basin and up to 1,000 km^2 in the east side of Uinta Basin of Utah. The land disturbed will range from 2-8 percent of the total of about 3,000 km^2 of good shale reserve land depending on the processing method used.[3] The production of about 2×10^9 m^3 (12 billion barrels) of oil would be associated with this land disturbance, assuming 8 percent of 3,000 $(km)^2$ and 12.5 ha per 10^6 m^3.

B. Water Impacts

1. Water Use

It is generally believed that available water will limit the ultimate size of an oil shale industry. All good western shale is in the upper Colorado River drainage system, the only replenishable source of water. There is ground water in the shale area, some of it fresh and some containing up to 60,000 ppm dissolved minerals. At present it is estimated that 2.2×10^8 cubic meters (180,000 acre feet) per year of Colorado river water could be made available for shale development. This quantity of river water, plus the use of ground water at the mine sites, would allow an overall industry size ranging from 2.4×10^5 to 4×10^5 cubic meters (1.5 to 2.5 million barrels) per day of shale oil.

The water used per unit of net product will depend upon the type of mining, retorting, and upgrading used. In situ methods are expected to require less water than conventional mining and retorting. Table 6 contains a list of estimated water use per cubic meter of shale oil produced. The values range from two to almost six cubic meters of water per cubic meter of shale oil.

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*References are listed at end of section.

Table 6

ESTIMATES OF WATER USE IN OIL SHALE PRODUCTION

(m^3 of water per m^3 of oil produced)

Impact[1]	Impact Quantity (m^3/m^3)	Reference	Impact Quantity (m^3/m^3)
Underground Mine Water Use	4.1	Colorado River Water Conservation District	3.6[2]
Surface Mine Water Use	4.0	Department of the Interior	2.70[3]-4.27 (underground)
In Situ Water Use	2.1	Cameron and Jones	2.89[4]
		Denver Research Institute	3.23[4]
		ARCO	3.90[5]
		Colorado Water Conservation Board	4.45[4]-5.57

Sources: [1]"Control of Environmental Impacts From Advanced Energy Sources," E. E. Hughes, E. M. Dickson, and R. A. Schmidt, SRI, Menlo Park, California, p. 34 (1974).

[2]Roland C. Fisher, "Colorado Oil Shale and Water," Quarterly of the Colorado School of Mines, Vol. 69, No. 2, pp. 135-6.

[3]Department of Interior, Final Environment Statement for the Prototype Oil Shale Leasing Program, Vol I, (1973).

[4]Felix C. Sparks, "Water Prospects for the Emerging Oil Shale Industry," Quarterly of the Colorado School of Mines, Vol. 69, No. 2 (April 1974).

[5]ARCO, "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado," Vol. I, Colony Development Operation (1974).

2. Water Quality

Current plans call for no effluent from the oil shale plant into surface water. Process water will be piped into the disposal area for wetting of the spent shale pile. Runoff from the pile will be held in a catchment dam below the disposal area. The amount of water piped from the Colorado River will not be returned. It is estimated that this consumptive use of water will increase the salinity of the Colorado River at Hoover Dam by 0.2 mg/l. By 1981, with a projected 40,000 m^3/day (250,000 B/D) industry, this will have caused a salinity increase of 1.0 mg/l.

Secondary water quality impacts which are not readily predicted or measured may be more significant. The Mahogany Zone, which will be the first oil shale layer to be mined, is the barrier or "lid" to the main aquifer in the area called the leached zone. Mining in this zone will encourage greater seepage of brackish water from this aquifer through the Mahogany Zone into the surface waters of the area. Mines to be located at the center of the basin, such as tracts C-a and C-b, will have to be dewatered at rates of at least 50 m^3/hr. In this area, about 70 percent of the water will be of poor quality.[4] This poor quality water will average about 25,000 mg/l in dissolved solids, contain mostly sodium and bicarbonate ions, and have chloride concentrations of 500-2,500 mg/l, according to a USGS source.[5] This water may not be recycled back to the plant for use and must be diverted onto the disposal pile, reinjected into lower aquifers, evaporated, or transported to nearby oil shale operations which need water for disposal and dust control.

The Treaty of 1944 assured Mexico of 1.9 x 10^9 m^3 (1,500,000 acre-feet) annually of irrigation water from the Colorado River. The river has become increasingly saline over the years due to dissolving of rock and the vast irrigation runoff from the southwestern United States. Two revisions have been made to the treaty, one in 1972 and the other in August 1974. The last revision calls for a maximum 115 ppm increase in total dissolved solids between Imperial Dam and Morelos Dam. Since the maximum advisable salinity at Imperial Dam is 1,000 ppm, the United States may not deliver to Mexico any water more saline than 1,115 ppm, TDS. In order to accomplish this, a plant will be built upstream from Morelos Dam to desalinate the Wellton-Mohawk drainage flow which is the main contributor of salinity in the lower part of the river. This drainage flow averages 8.6 m^3/sec (220,000 acre-feet/year) with a salinity of 3,700 ppm.

C. Air Impacts

Industrialization of the Western shale regions will result in a decline of the general air quality. The main sources of air pollution will be vehicular emissions from mining, construction, and transporting equipment; dust from shale-handling operations; and gases from retorting and refining units. Other sources of air degradation will be the increased vehicular traffic, residential heating caused by an increase in population in the area, and emissions from the mine-blasting procedures. The estimated emissions for an oil shale plant are given in Table 7. The first two columns show the numbers listed in the previous EPA report. The third column lists the figures derived from an ARCO primary reference. The fourth column shows the ARCO emissions as listed in a secondary source based on ARCO's data. In the fifth column are listed the emissions predicted by the Department of the Interior. The more recent numbers listed in the third and fourth columns show a ten times increase in NO_x emissions. This is because the older estimates were based on the use of natural gas or clean fuel in the retorting operation. Now the estimates are based on the use of shale oil, which has greater nitrogen content.[6]

Table 7

ESTIMATES OF AIR POLLUTANT EMISSION FACTORS IN OIL SHALE PRODUCTION

Pollutant	Emission Factor in kg per m^3 of Oil Product				
	Table 11[1]	Table 16[2] (uncontrolled Class IV)	Tosco II[3]	Tosco II[4]	Department of Interior[5]
SO_2	11	22.6	2.25	1.91	2.62-3.88
NOx	0.68	0.755	7.45	11.1	0.456-0.685
Particulates	0.054	1.13	1.46	1.43	2.52
H_2S	--	11.3	--	--	--

Sources: [1]"Control of Environmental Impacts from Advanced Energy Sources," E. Hughes, E. Dickson, R. Schmidt, SRI, Menlo Park, California, Table 11 (1974).

[2]ibid., Table 16.

[3]SRI calculations based on "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado," Vol. I, Colony Development Operation (1974).

[4]SRI estimate from other sources.

[5]Cited in "Environmental Considerations in Energy Development," Appendix D, Battelle Memorial Institute (1973).

D. Aesthetic Impacts

The spectrum of changes caused by the development of a new industry ranges from those that are easily quantified, such as size of mine tailing area, to effects that are purely subjective, such as increased monotony of landscape. For convenience, all environmental changes that contain a high proportion of subjective evaluation are placed in the aesthetic category. This category includes changes in land use, plant growth, wildlife, recreational facilities, and cultural and scenic values.

The shale areas have a low population density, on the order of one person per square kilometer (three per square mile) less than half of whom live in towns. The population doubles during the few weeks of the deer-hunting season. Advanced planning of mine and process facility locations would allow the preservation of the few historic Indian culture ruins in the area. The quantity of shale residue accumulating in surface disposal areas will eventually create large plateau areas in a region that consists of rounded hills and deeply cut canyons.

Mining, transportation, and processing operations will produce noises similar to those now being experienced in other related industries. In addition to the usual human discomfort and loss of working efficiency, industrial noises will adversely affect the wildlife in the immediate area. For the most part, noise control methods developed for other industrial and transportation equipment will be satisfactory for the shale industry. There may be instances where long conveyor systems used between processing units create enough noise to prevent normal wildlife migration paths from being used, even though there is no physical barrier.

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1. Atlantic Richfield Company, "An Environmental Impact Analysis for a Shale Oil Complex at Parachute Creek, Colorado," Vol. I, Part I, Colony Development Operation (1974).

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3. R. G. Murray, "Energy from Oil Shale," EPA-600/2-74-002, SRI Project No. 2714, Stanford Research Institute, Menlo Park, California (March 1974).

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6. Private communication with Mr. Robert Smith, Colony Development Operation.

VII AIR POLLUTION: EMISSIONS AND AMBIENT AIR QUALITY

A. Background

Concern over possible environmental degradation has been engendered by the proposed construction of new oil shale processing facilities in the oil shale regions of Colorado and Utah. Federal and State laws require review of the environmental impact of proposed sources of air pollution in view of current air quality standards. If an impact assessment reveals that pollution levels resulting from a new facility will exceed the standards, adequate control measures must be proposed before a building permit will be issued. Since the impact assessment is required during the planning stages of plant development, a rational methodology must be devised that will utilize appropriate emission and meteorological data in the prediction of pollutant concentrations. Simulation modeling provides the necessary link between the collections of meteorological and emission data and the picture of air quality that is required for successful evaluation of control measures. Modeling permits assessment of the ramifications of projected growth patterns and emission control procedures.

Somewhat limited studies of the environmental impact of proposed oil shale recovery schemes have been conducted. One such study was performed by Engineering Science, Incorporated (ESI) and described in the Department of Interior's Final Environmental Statement[1*] on oil shale. ESI used the emission estimates then available, various meteorological data, and a number of assumptions as to stack characteristics and locations in a

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[*] References are given at the end of this section.

mathematical model to predict air quality levels resulting from an oil shale facility.*

B. Model Description

The model used in the present study for calculation of concentrations from oil shale plants is the Climatological Dispersion Model (CDM), which is a revised form of a model first proposed by Martin and Tikyart.[2] The CDM has been described in detail by Calder.[3]

The computerized CDM permits calculation of long-period seasonal or annual average pollutant concentration patterns resulting from stationary point sources and area sources. The fundamental physical assumption of the model is that the steady-state spatial distribution of concentration from a continuously emitting point source is given by the Gaussian plume formula. It is assumed that meteorological conditions over short periods of time (of the order of an hour) can be regarded as steady-state, and that these conditions can be approximated with a constant and spatially uniform wind speed and with a unique horizontal mean wind direction for the entire area.

The Gaussian plume formulae are used when there are no restrictions on diffusion in the vertical direction. When vertical diffusion is restricted to a finite mixing depth, a uniform vertical concentration distribution is assumed at greater downwind distances.

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*Note added in review: Subsequent to the Department of Interior's environmental statement, ESI has extended its work by contributing an air quality analysis to the Federal Energy Administration's Oil Shale Task Force for the Project Independence Blueprint, published at the end of 1974.

Equations for the long-term average concentrations due to point and area sources are weighted according to a frequency function to account for the variability of meteorological conditions. These empirical functions express the observed joint frequency of occurrence of various classes of wind direction, wind speed, and stability. Integration of the formulae over the area and point sources will describe the concentration that would be observed at a selected location for a certain set of meteorological conditions. These concentrations, taken together with the frequency of occurrence of each combination of conditions, produce the required climatologically averaged spatial distribution of concentration.

The CDM program formulation used in this study assumes that the land at the plant site and in the surrounding area is essentially flat. The influences of complex terrain have not yet been incorporated into dispersion models currently in use.

C. Topography of the Oil Shale Region*

The principal oil shale deposits considered in this study are located in the Piceance Creek Basin in Colorado and the Uinta Basin in Utah.

The Colorado Counties of Rio Blanco, Garfield, and Mesa encompass the Piceance Creek Basin. The major oil shale area of the Basin lies on the Roan Plateau, bounded by steep escarpments in all directions. The land surface of the region has been shaped by erosion into valleys and ridges oriented in the north and north-easterly directions. The

*The information contained in this section was extracted from the Final Environmental Statement for the Prototype Oil-Shale Leasing Program, Vol. I, Regional Impacts of Oil Shale Development, U.S. Department of the Interior (1973). This is Reference 1 in the list at the end of this section.

difference in elevation from ridge to valley floor ranges from 62 to 185 m (200 to 600 feet), and for the most part the valleys are narrow and steep sided. The northern part of the oil shale area is drained by tributaries of the White River, while the Colorado River drains the southern part of the oil shale region. Land elevations above mean sea level (MSL) range from about 1600 m (5250 ft.) near the White River to about 2800 m (9000 ft.) on southern ridge crests.

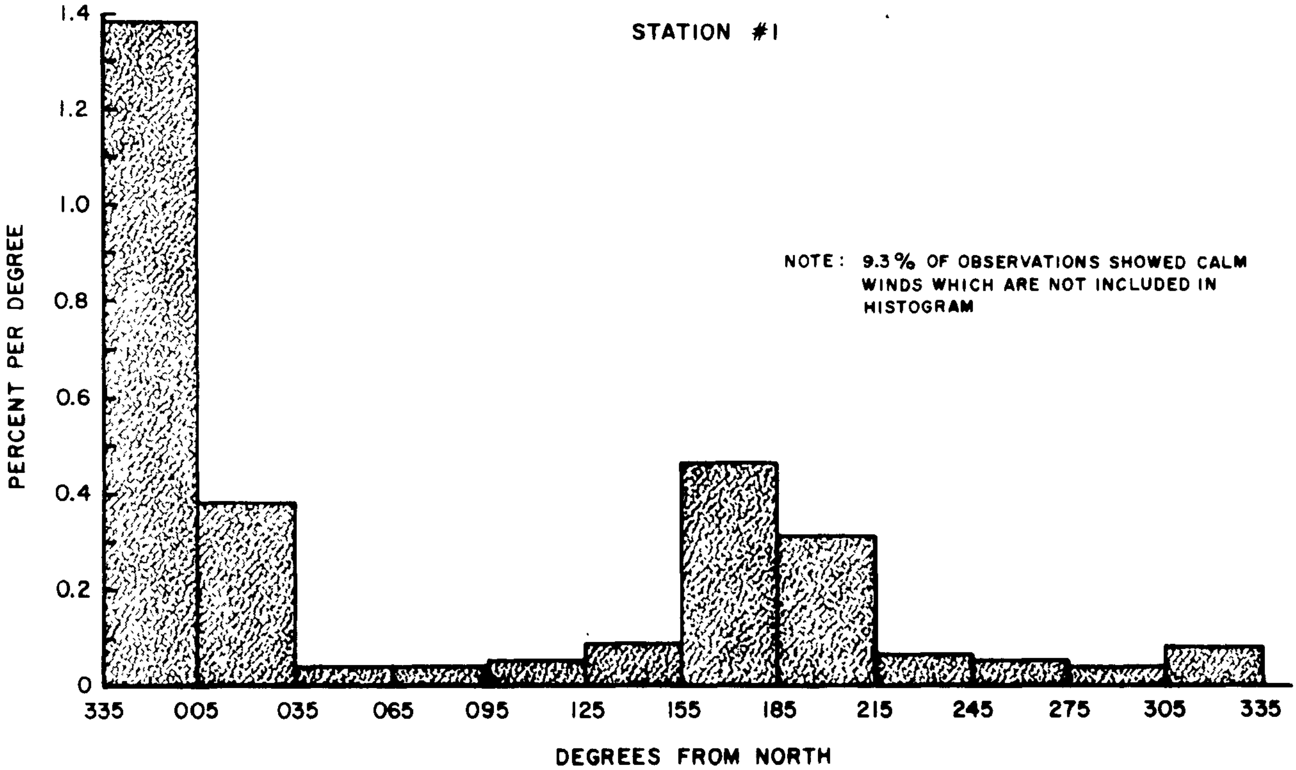
Utah's Uinta Basin is a depression bounded by the Uinta and Wasatch Mountains, the Roan Cliffs and the cliffs west of the Douglas Creek Arch. Land features include rough mountains and flat valleys, with deep gulleys and rock capped ridges. The White and Green Rivers drain the area. Elevations range from 1400 m (4600 ft.) to more than 2500 m (8000 ft.) MSL.

In general, the oil shale regions of Colorado and Utah contain many steep-sided valleys that are unsuitable locations for plant sites. In the past, serious air pollution episodes have occurred in such valley locations as the Meuse Valley, Belgium in 1930 and at Donora, Pennsylvania, in 1948. These episodes were a result of restriction by valley walls of mixing of pollutants into the atmosphere. Conclusions from a study[4] conducted by Battelle, Pacific Northwest Laboratories indicate that oil shale processing facilities should be located on plateau, rather than valley, sites to minimize pollution potential. Concentrations in a valley resulting from a plateau plant site were found to be at least an order of magnitude lower than the concentrations that would result from a valley plant site. Therefore, in view of compelling supportive evidence for the necessity of such location, the diffusion modeling performed in the present study was conducted under the assumption that the oil shale plants will be located on plateau sites.

D. Meteorology of the Oil Shale Region

The Climatological Dispersion Model used to simulate the pollutant pattern resulting from operation of an oil shale facility was formulated assuming flat terrain in the modeling area. If an oil shale plant is located in a narrow valley, the CDM will under-predict pollutant concentrations. However, if the facility is located in a plateau or in a broad valley, as previous studies have strongly recommended and which has been assumed for the modeling, the dispersion model will adequately predict concentration patterns. The wind regimes of plateaus and broad valleys in the oil shale region are undoubtedly influenced by surrounding terrain, but the influence is not of sufficient magnitude, as is that of steep-sided valleys, to justify modification of the CDM to account for it.

Figures 5 and 6 are illustrations of the influence of topography on wind direction and speed. The data used in these figures were taken from a report[5] prepared by Dames & Moore for the Colony Development Operation and from Grand Junction, Colorado, weather records. Stations 1, 2, and 5 are weather stations that were established in the oil shale area of Colorado to collect data for the above study. Station 1 was located at the confluence of the Middle Fork and the East Middle Fork of Parachute Creek at an elevation of 1850 m (6025 ft.) MSL. Station 2 was part way up the valley side of the Middle Fork of Parachute Creek at an elevation of 1930 m (6270 ft.) MSL. Station 5 was located on top of the Mesa above the Middle Fork of Parachute Creek. The annual frequency distributions of wind direction for each station and for Grand Junction are shown in Figure 5. Since the class intervals of wind direction reported for the experimental stations differ from the class intervals reported for Grand Junction, the percent frequency of occurrence per degree of class interval has been used in the figure. This normalizes



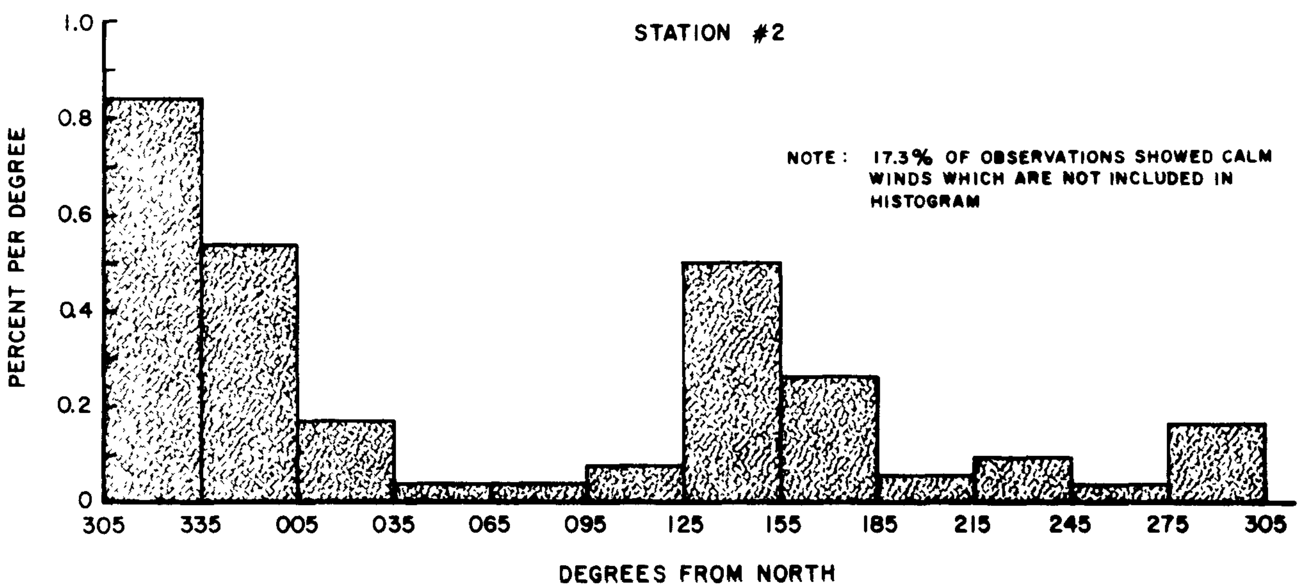
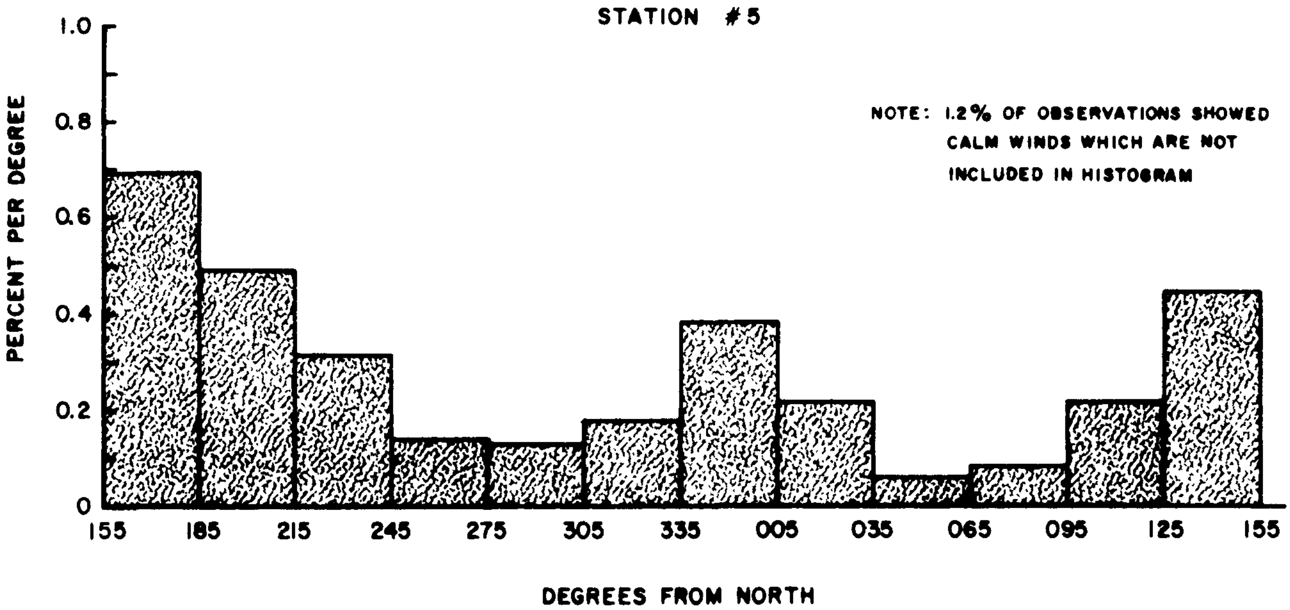


FIGURE 5 ANNUAL FREQUENCY DISTRIBUTIONS OF WIND DIRECTION AT FOUR COLORADO SITES



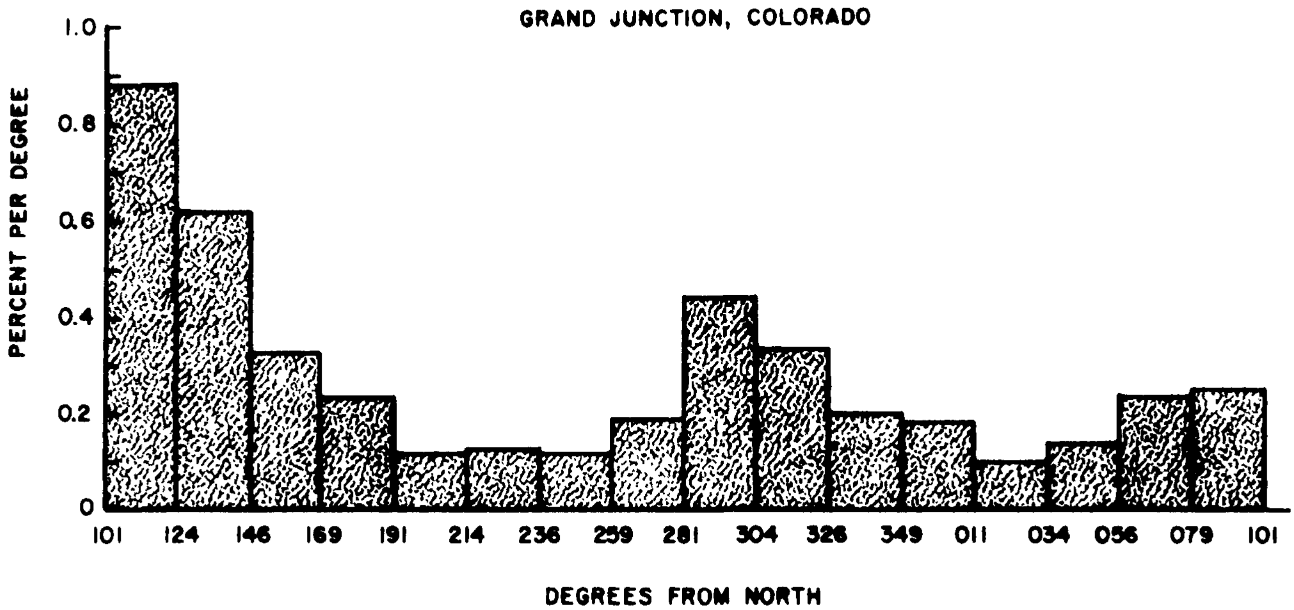
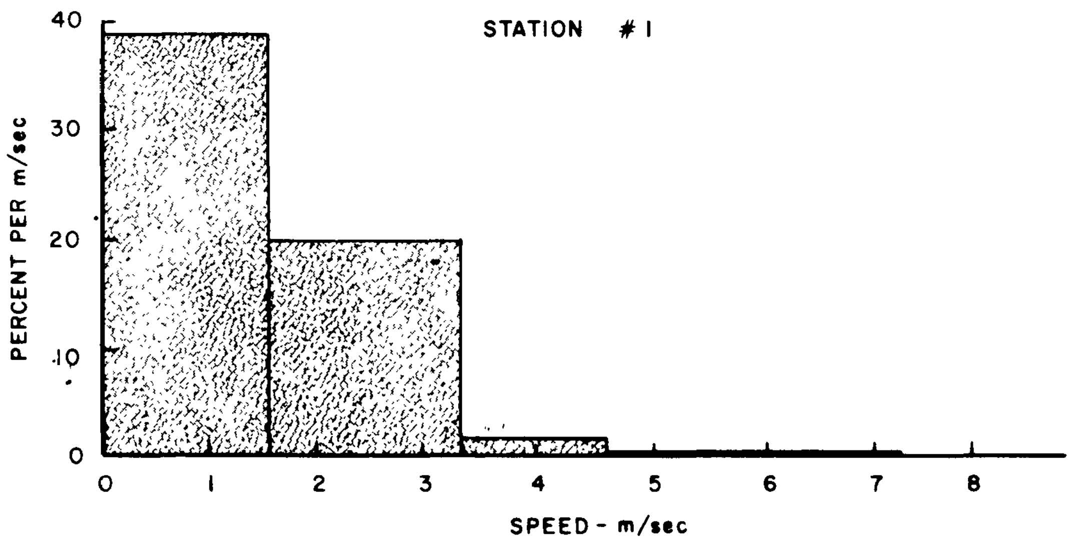


FIGURE 5 (Concluded)



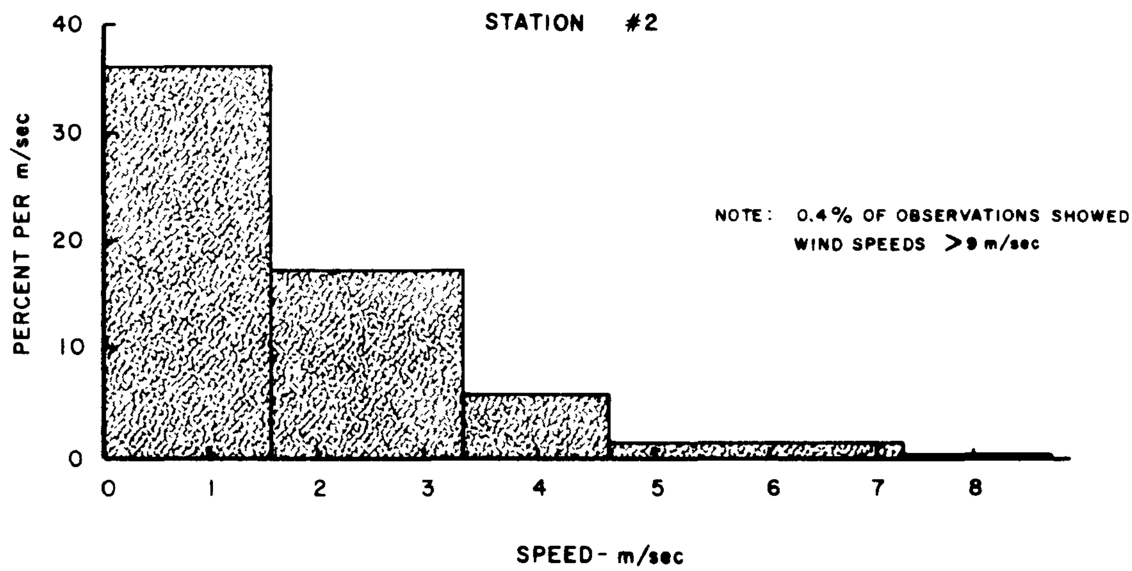
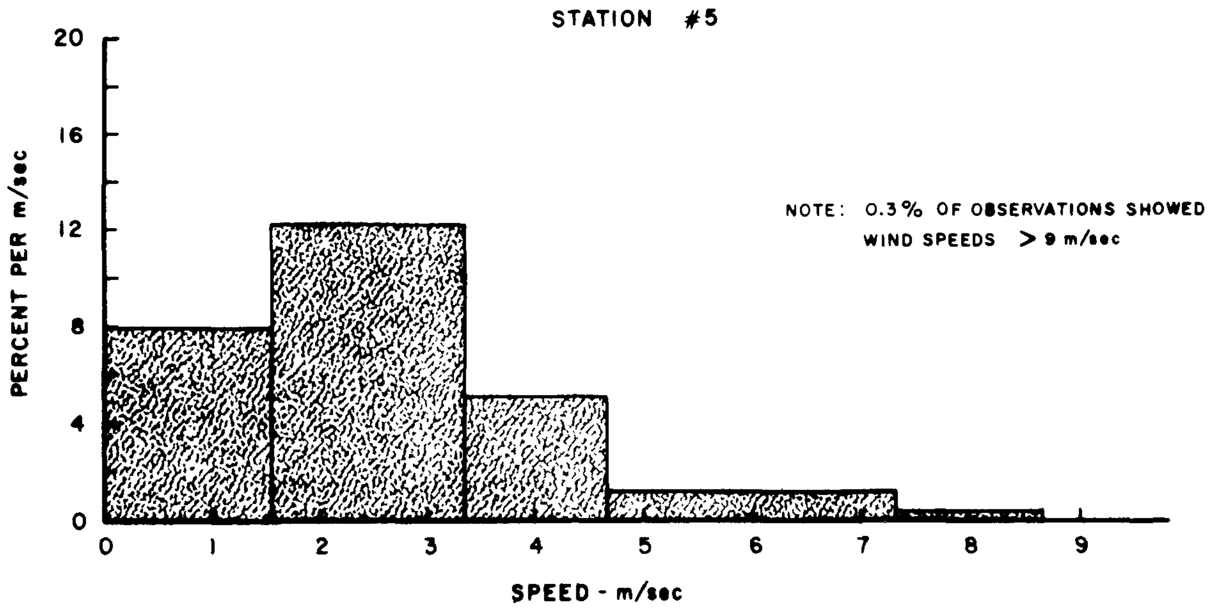


FIGURE 6 ANNUAL FREQUENCY DISTRIBUTIONS OF WIND SPEED AT FOUR COLORADO SITES



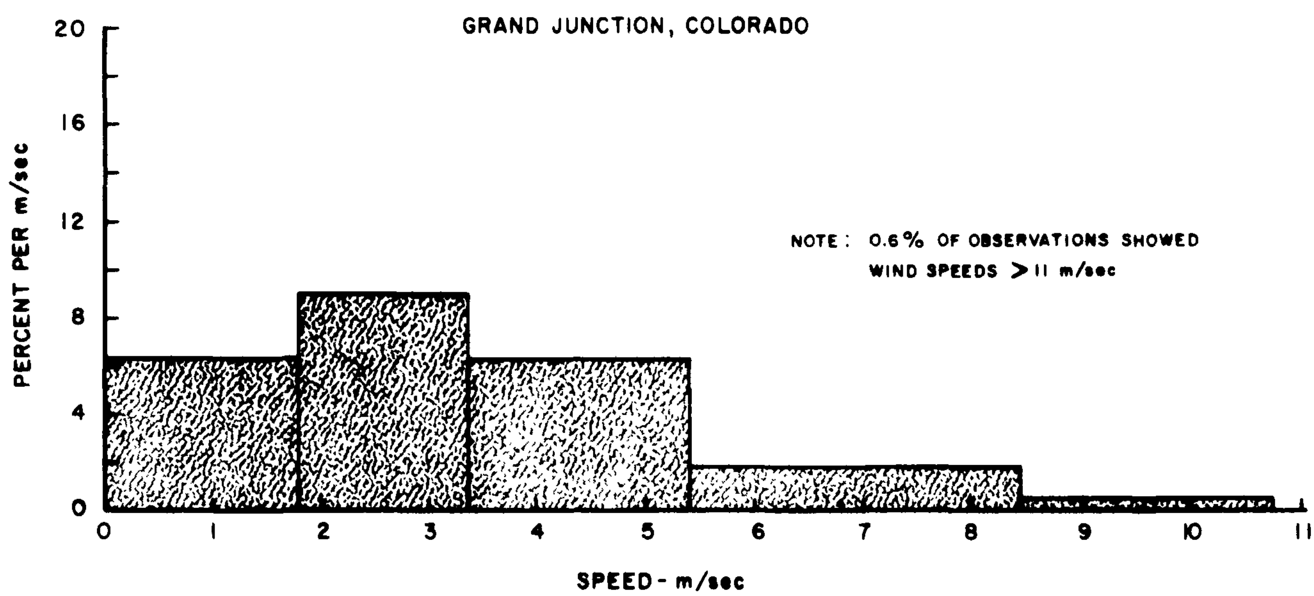


FIGURE 6 (Concluded)

the data so that the vertical scales are comparable. The histograms were drawn so that the class interval with the greatest frequency appears on the left and subsequent class intervals are taken clockwise from it. This was done so that the bimodal nature of the wind direction distribution would be most apparent for comparison purposes. Stations 1 and 2 show strong channeling of the wind by the valleys, with the orientation of the maxima reflecting the orientation of the valley. Station 5, located on the plateau, and Grand Junction, located in a broad valley, have less pronounced maxima and their patterns are rotated 180° from those of Stations 1 and 2. It is evident from examination of Figure 5 that the variability of wind direction from station to station in the oil shale area is at least as great as the variability between Grand Junction and any station. Grand Junction data best approximates the wind direction distribution of the mesa site, and the differences between the two distributions are no greater than those between other sites suitable for oil shale processing facilities.

Figure 6 illustrates the wind speed frequency distributions for the same locations cited above. Here the frequencies have been plotted in percent per unit of speed, since the speed class intervals differed for the two data sets. The valley stations show greater frequencies of occurrence in the low wind speed classes than do Grand Junction and the mesa station. Grand Junction has somewhat more occasions of the higher wind speed classes than Station 5. However, it should be noted that the frequency distributions of Stations 1, 2, and 5 were based on only 14 months of data, while Grand Junction distributions were based on five years of data.

Sufficient meteorological data for application of the CDM is not available for sites within the oil shale region. Atmospheric stability seldom varies abruptly within a geographic area, so the use of the stability at Grand Junction is a good approximation. In view of the previous discussion and since specific sites for the processing facilities and the associated meteorology have not been supplied, the use of Grand Junction meteorology is justified for obtaining order of magnitude estimates of pollutant concentrations. A similar argument can be made for the applicability of Salt Lake City, Utah, data. In order to produce detailed pollutant patterns for an oil shale development, specific meteorological and stack data for a proposed site must be used.

E. Dispersion Modeling

1. Cases Adopted

The CDM has been used to predict air pollutant concentrations resulting from 16,000 m^3/day (100,000 barrel per day) plants using two different retort processes, the TOSCO II process and an in-situ process. Concentrations of particulates, SO_2, HC and NO_x were calculated over the same averaging periods as those for which air quality standards exist. These periods include annual averages for particulates, SO_2 and NO_x; 24-hour averages for particulates and SO_2; and a 3-hour average for HC.

Annual averages were calculated from frequency distributions of meteorological conditions observed at Grand Junction, Colorado, and Salt Lake City, Utah. These distributions are the output of the National Climatic Center's* STAR computer program. Twenty-four hour averages and 3-hour averages were calculated using the assumption that worst-case

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*U.S. Department of Commerce
National Oceanic and Atmospheric Administration
Environmental Data Service
National Climatic Center
Federal Building
Asheville, N.C. 28801

meteorological conditions prevailed. Statistical weather records indicate that neutral atmospheric stability and a light wind of 1.5 m sec^{-1} occur for 24 hours or longer in the oil shale region an average of 15 days per year. These conditions have been shown to be representative of worst-case conditions in the oil shale region and do not involve use of Grand Junction or Salt Lake City meteorological data. The CDM was used to compute the 24-hour and 3-hour averages, for various wind directions, assuming 100 percent frequency of occurrence of neutral stability and 1.5 m sec^{-1} winds. Stack configurations were assumed on the basis of the best available information. Radical changes in the assumed configurations (see Figures 2 and 3 in Section IV) could result in concentrations somewhat different than those presented here.

2. Results for TOSCO II Retorting

Figure 2 (in Section IV) illustrates the configuration of stack locations that have been assumed for a 16,000 m^3/day (100,000 barrel per day) TOSCO II plant. Table 8 gives the stack characteristics and emission rates used in model calculations. Isopleths of concentrations for various pollutants and averaging times are shown in Figures 7-18. Tables 9 and 10 summarize model results for the TOSCO II process and give background concentrations, air quality standards, and the level of control required to meet each standard. Background concentrations were taken from the results[6] of monitoring conducted in the Colorado oil shale region by Colony Development Operation. When computing the required level of control, background concentrations and concentrations resulting from oil shale operations have been considered together for the federal primary and secondary standards and for the Colorado standards. This has been done by subtracting the background concentration from the standard and then computing the level of control needed so that the concentrations resulting from oil shale facilities do not exceed the remaining

Table 8

STACK PARAMETERS AND EMISSION RATES FOR A 16,000 m^3/D (100,000 B/D) TOSCO II PLANT WITH EMISSIONS CONTROLLED*

Location†	Line No.‡	Description of Unit	Flow Rate§ (All Stacks) m^3/sec	Temp. °C	Number of Stacks	Stack Height m	Stack Diameter m	Gas Exit Velocity m/sec	Emissions (Total for all Stacks) Particulates g/sec	SO_2 g/sec	HC g/sec	NO_x g/sec
1	61	Hydrogen Unit	317	260	2	30.5	3.0	21.7	2.7	81.0	-	135.4
2	62	Naphtha Hydrogenation	7	427	1	24.4	0.9	10.8	0.05	1.3	-	2.3
3	62	Gas Oil Hydrogenation: Feed Heater	36	427	2	24.4	1.8	6.8	0.23	1.8	-	10.8
4	62	Gas Oil Hydrogenation: Fired Reboiler	31	427	1	24.4	2.1	8.6	0.20	1.5	-	9.1
5	63	Sulfur Plant	30	38	1	76.2	1.5	16.6	-	16.1	-	-
6	64	Delayed Coker	45	260	1	24.4	1.8	17.2	0.39	11.3	-	18.9
7	66	Steam Superheater—Ball Stack	244	54	12	76.2	1.8	7.8	11.1	5.3	-	33.6
8	65	Raw Shale Preheat	1160	54	12	76.2	4.0	7.8	52.8	257.0	75.6	297.0
9	69	Processed Shale Moisturizer	119	91	12	12.2	1.2	8.4	5.6	-	-	-
10	70	Primary Crusher	236	16	2	15.2	2.4	25.2	10.8	-	-	-
11	70	Final Crusher	283	16	20	15.2	1.2	12.1	13.1	-	-	-
12	70	Fine Ore Storage	76	16	2	15.2	1.5	20.6	3.3	-	-	-
13	66	Utility Boilers	49	260	4	15.2	1.2	10.8	2.5	18.6	-	6.9

*Assumed best available control as specified in Section IX of this report.

†Location refers to Figure 2.

‡Line number refers to Figure 1 and Table 1.

§To convert to ACFM multiply by 2120.

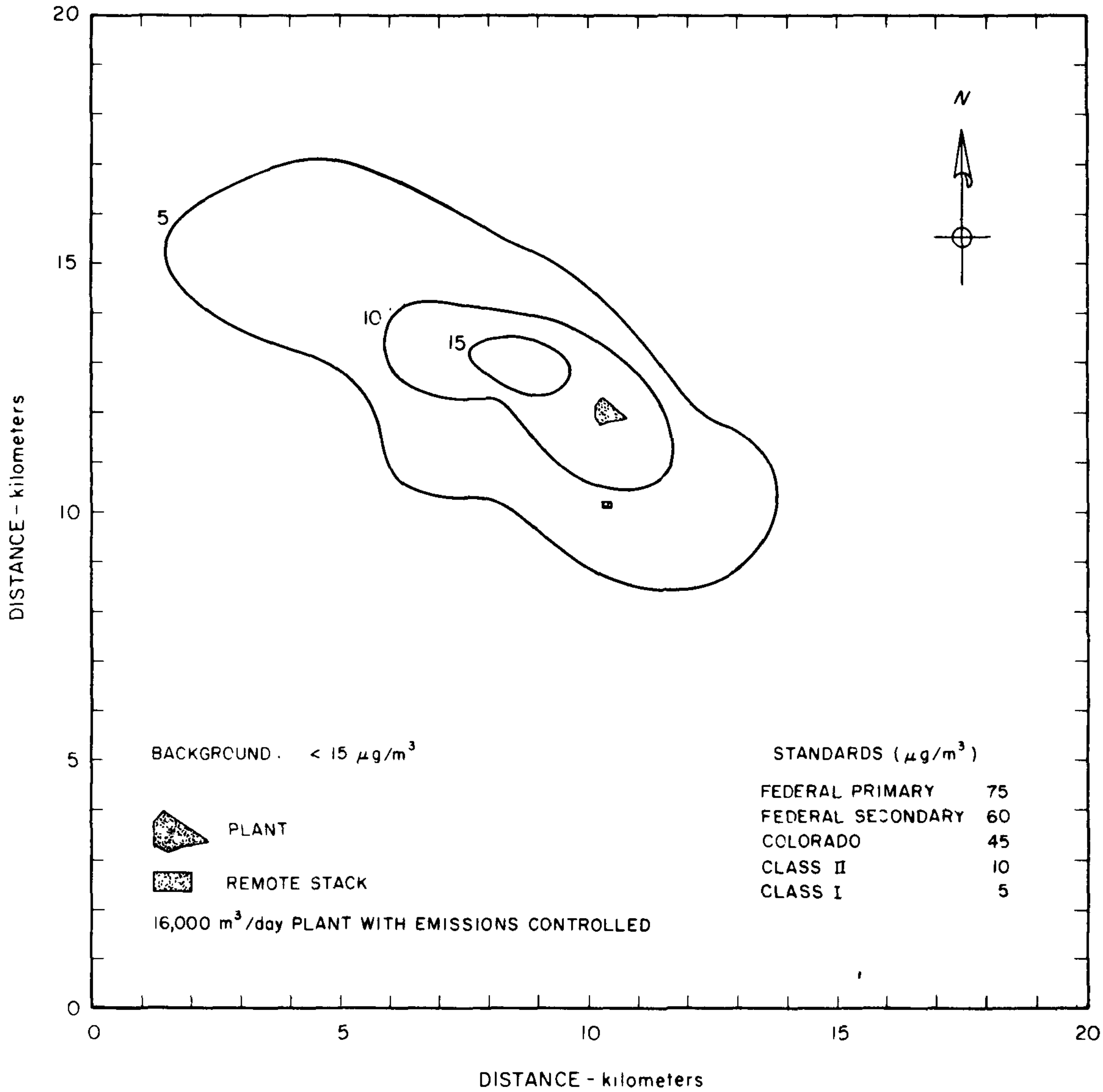

FIGURE 7 ANNUAL AVERAGE PARTICULATE CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING GRAND JUNCTION, COLORADO METEOROLOGY

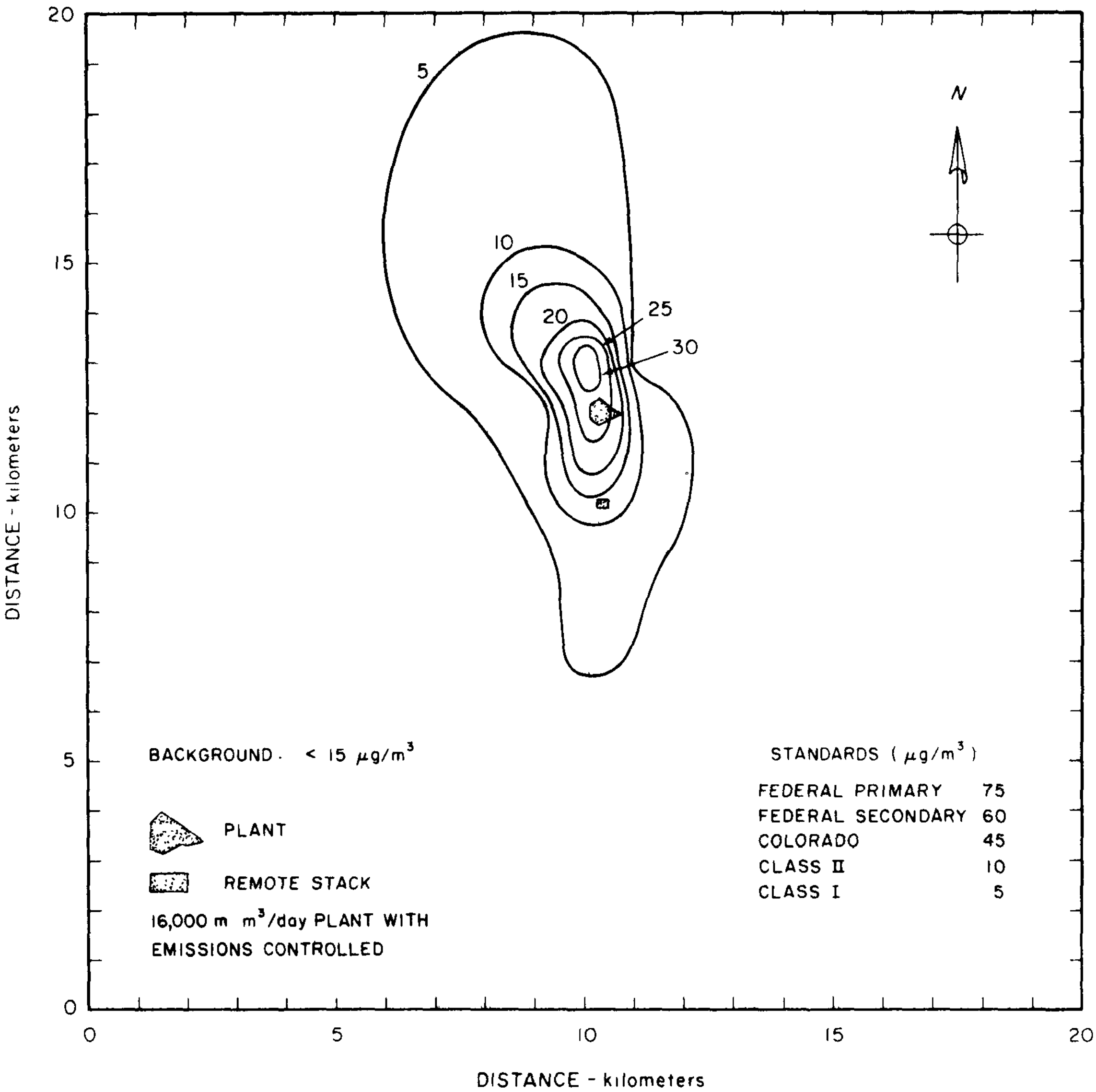

FIGURE 8 ANNUAL AVERAGE PARTICULATE CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING SALT LAKE CITY, UTAH METEOROLOGY

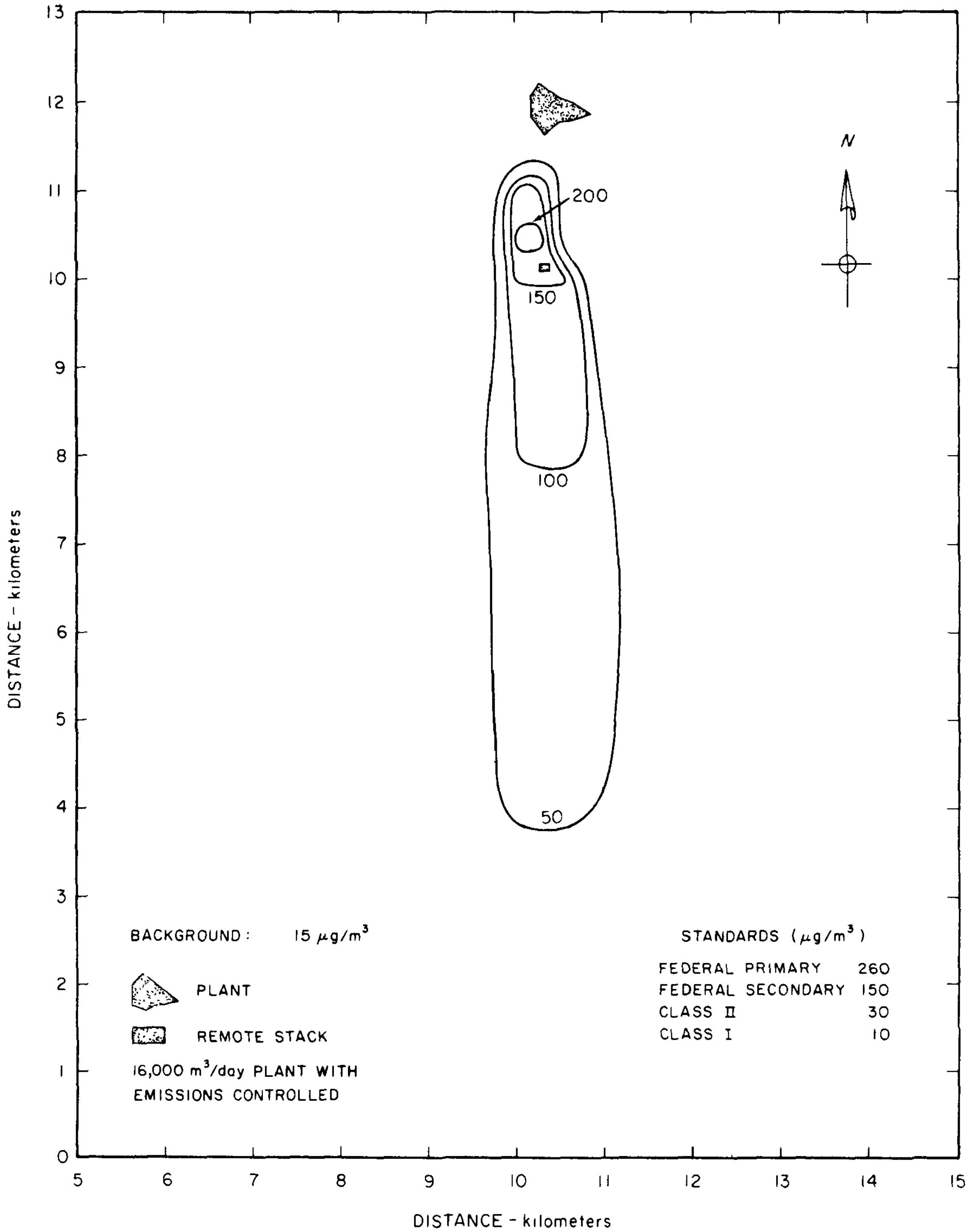

FIGURE 9 24-HOUR WORST CASE AVERAGE PARTICULATE CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A NORTH WIND OF 1.5 $msec^{-1}$

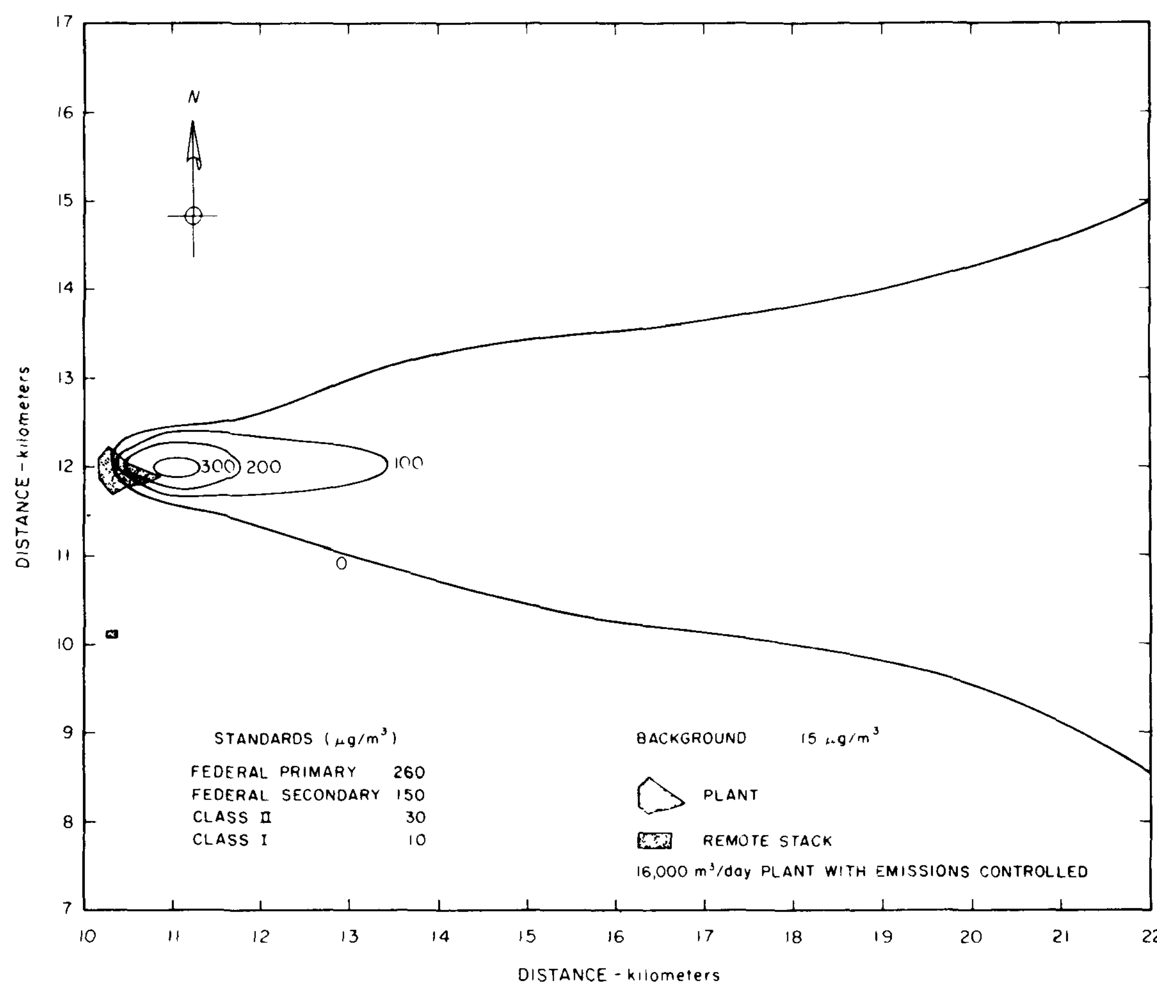

FIGURE 10 24-HOUR WORST CASE AVERAGE PARTICULATE CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A WEST WIND OF 1.5 $msec^{-1}$

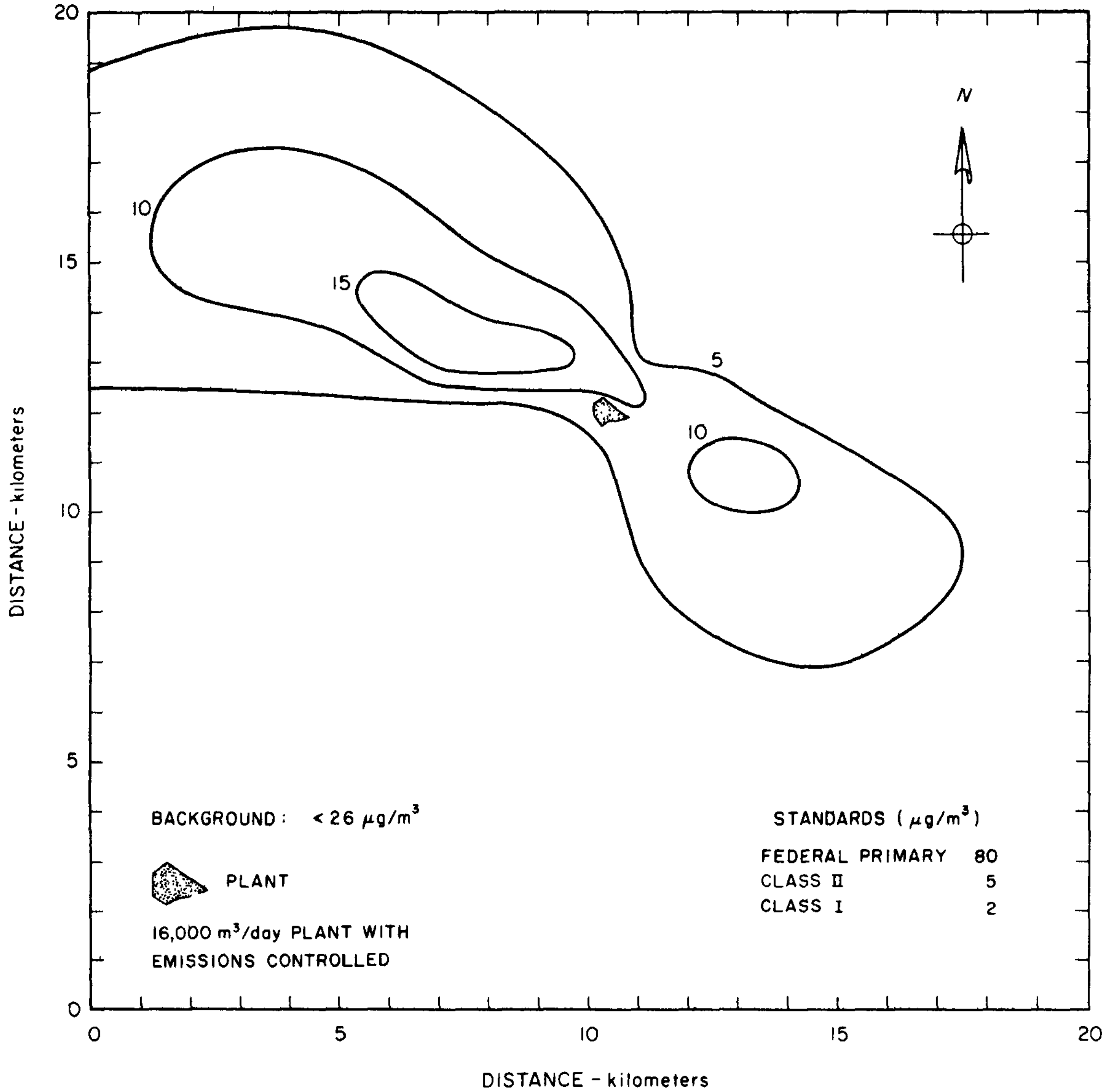

FIGURE 11 ANNUAL AVERAGE SO_2 CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING GRAND JUNCTION, COLORADO METEOROLOGY

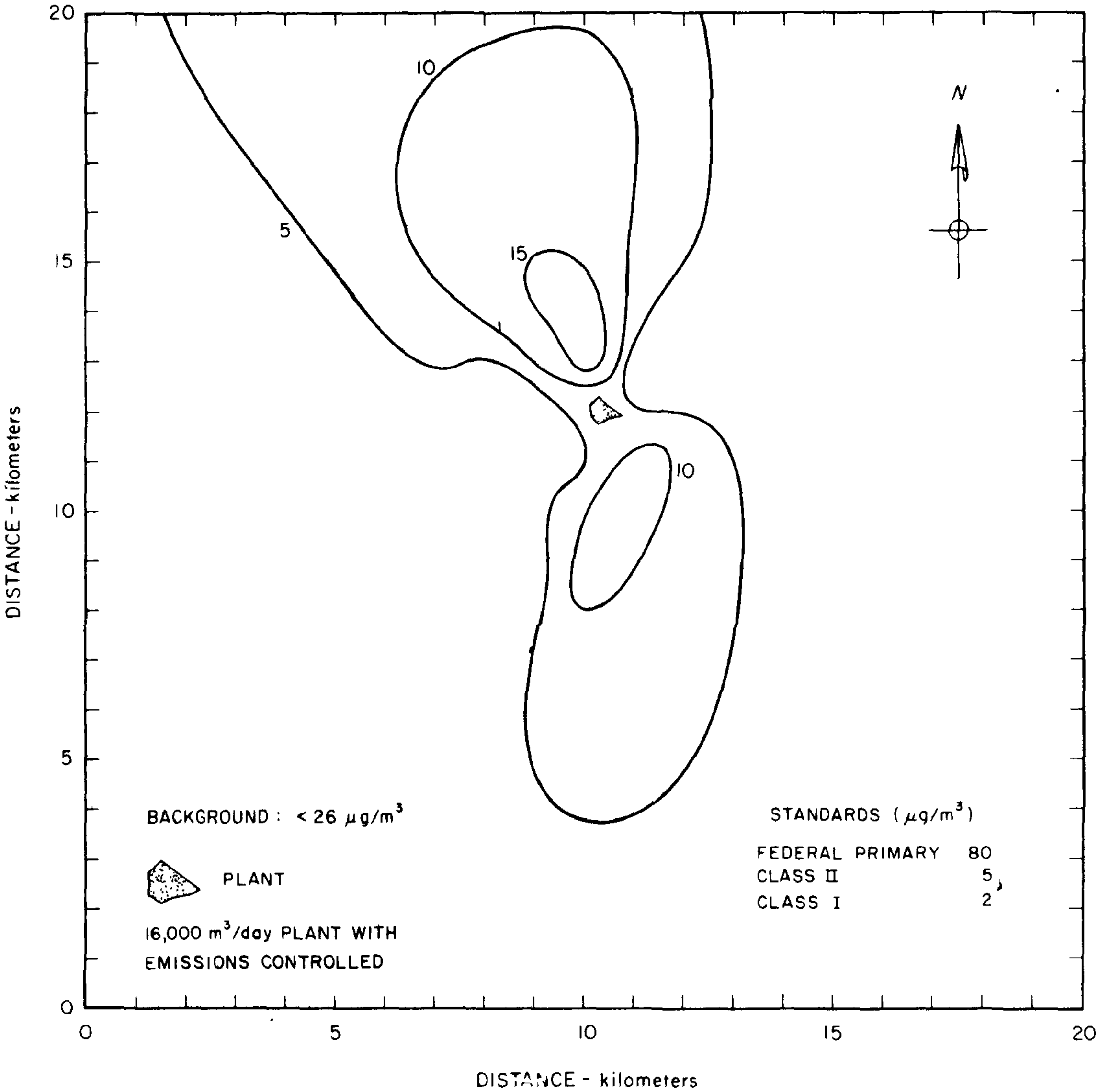

FIGURE 12 ANNUAL AVERAGE SO_2 CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING SALT LAKE CITY, UTAH METEOROLOGY

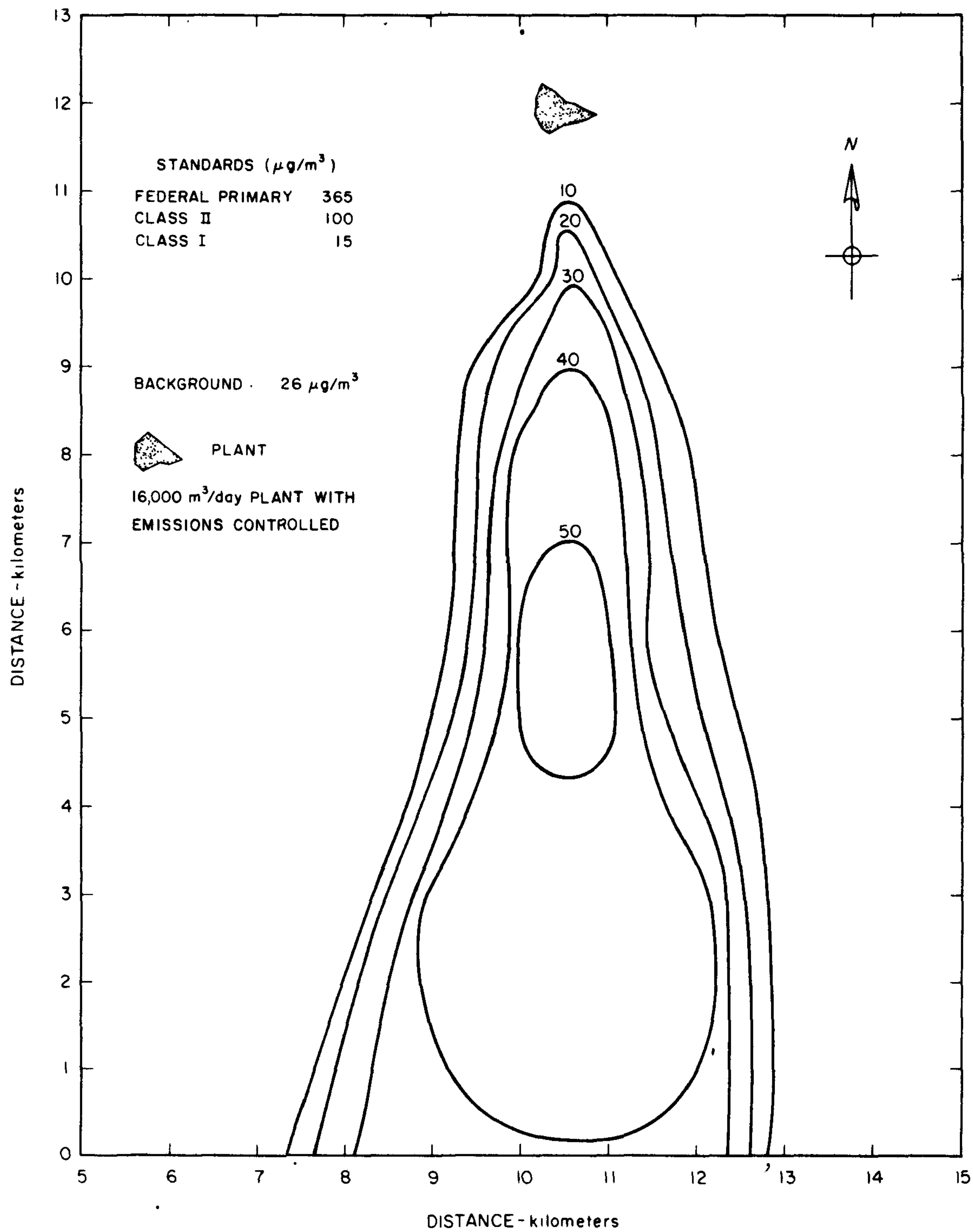

FIGURE 13 24-HOUR WORST CASE AVERAGE SO_2 CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A NORTH WIND OF 1.5 $msec^{-1}$

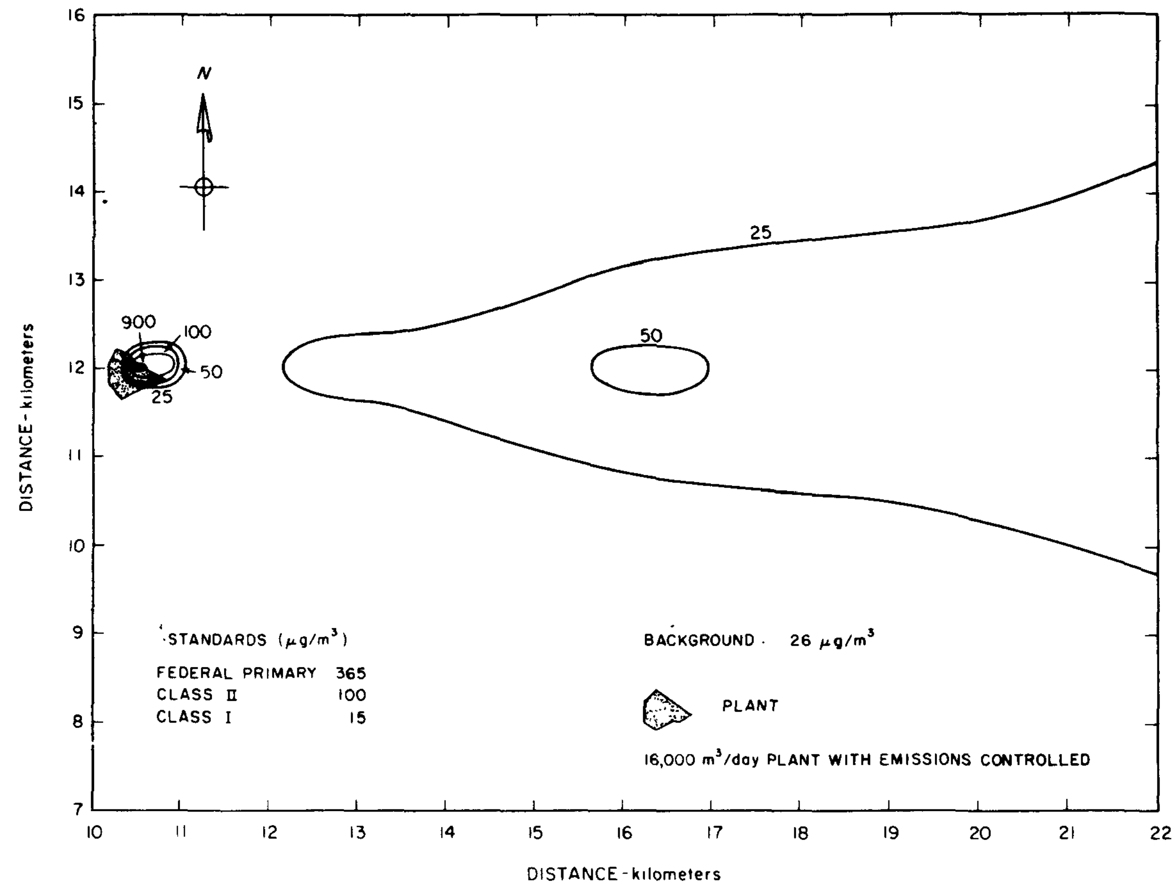

FIGURE 14 24-HOUR WORST CASE AVERAGE SO_2 CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A WEST WIND OF 1.5 $msec^{-1}$

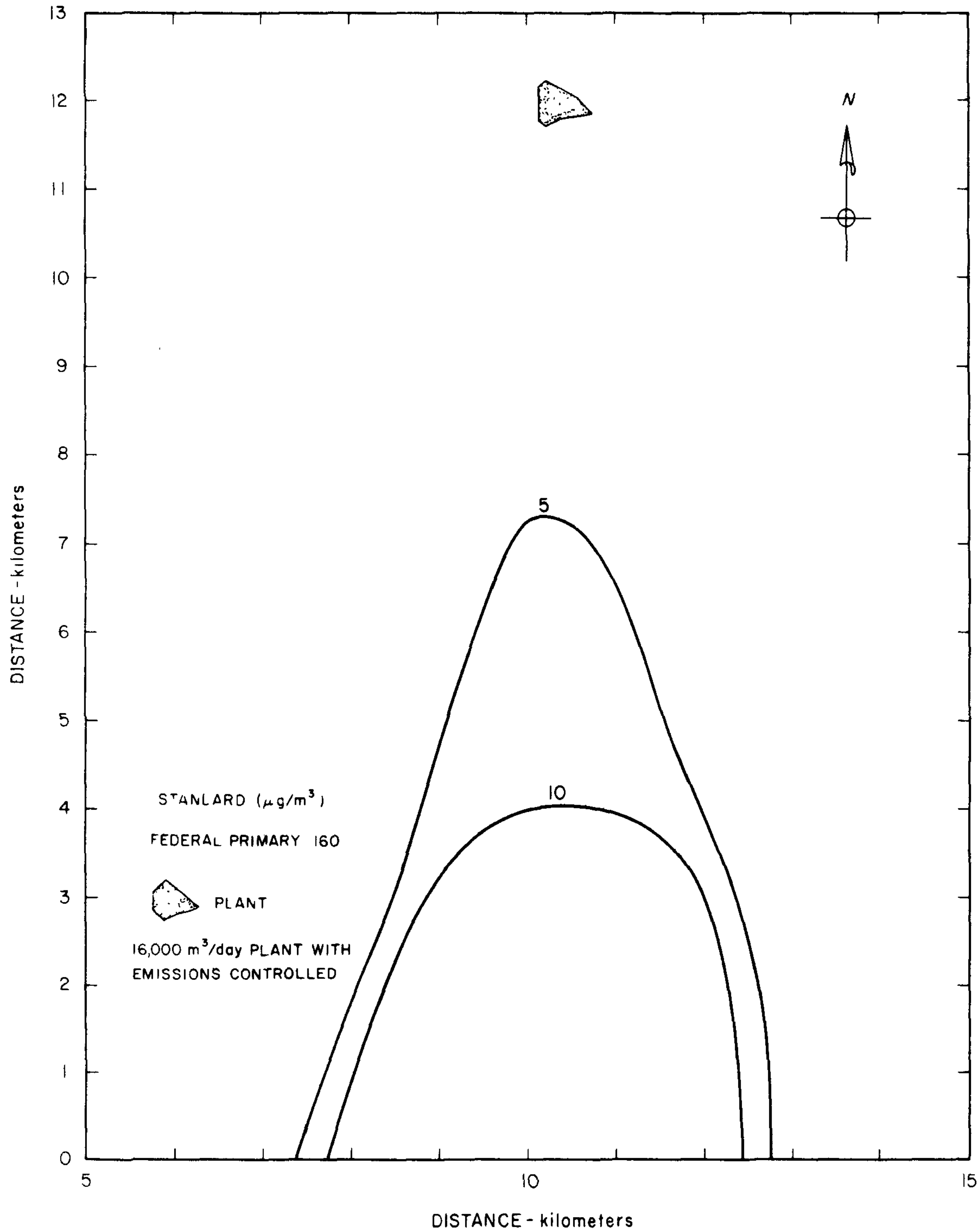

FIGURE 15 3-HOUR WORST CASE AVERAGE HC CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A NORTH WIND OF 1.5 $msec^{-1}$

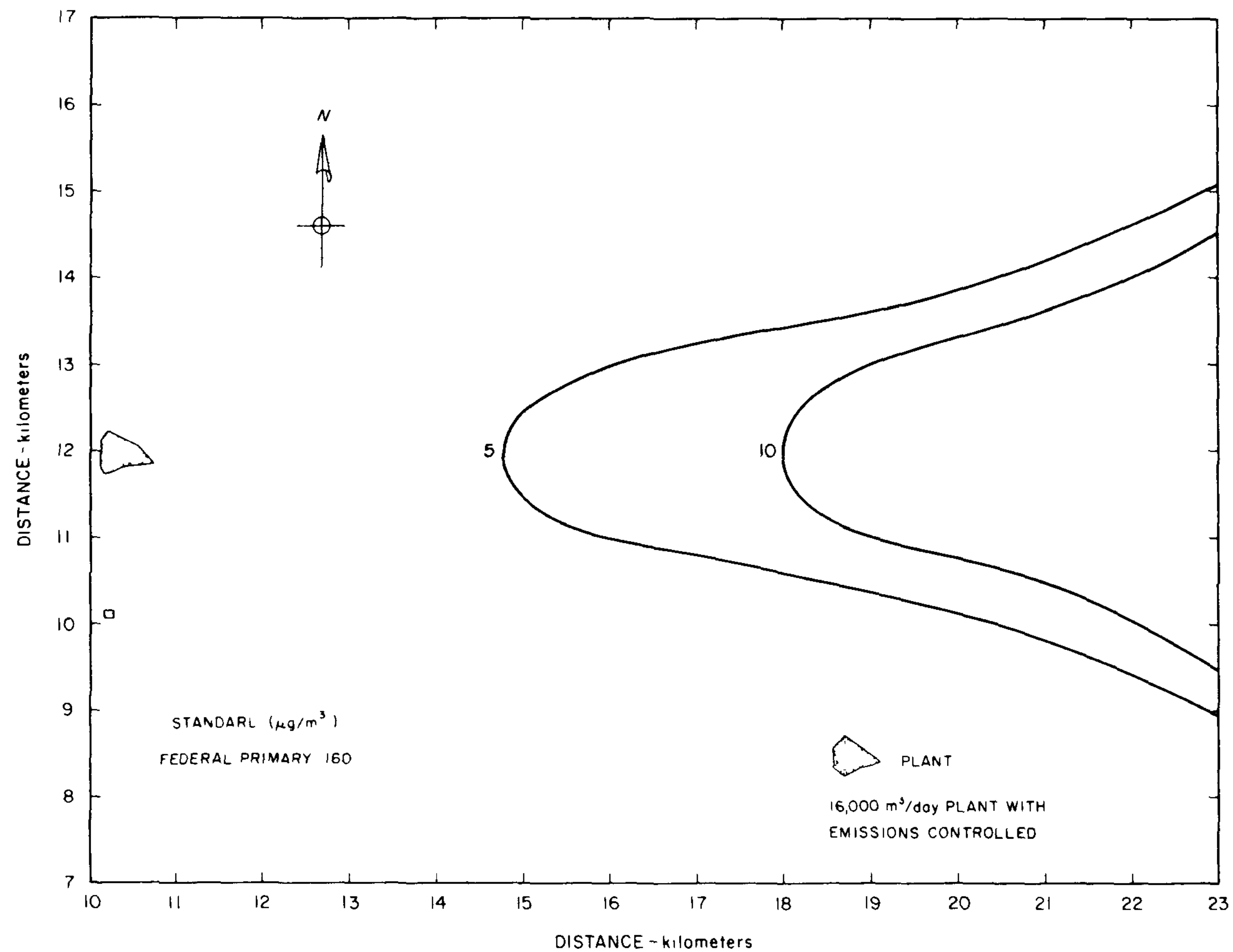

FIGURE 16 3-HOUR WORST CASE AVERAGE HC CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT UNDER CONDITIONS OF NEUTRAL STABILITY AND A WEST WIND OF 1.5 $msec^{-1}$

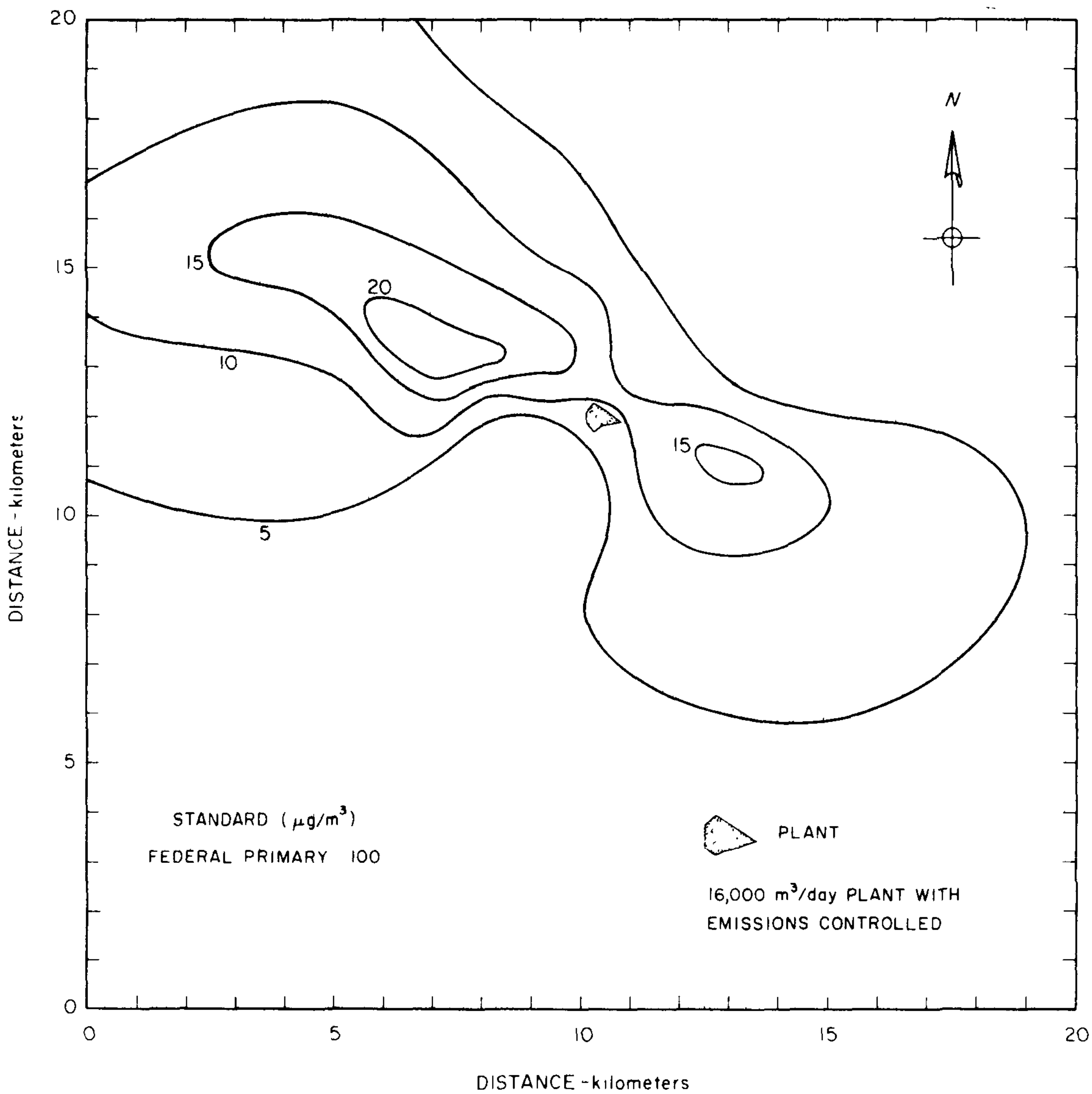

FIGURE 17 ANNUAL AVERAGE NO_x CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING GRAND JUNCTION, COLORADO METEOROLOGY

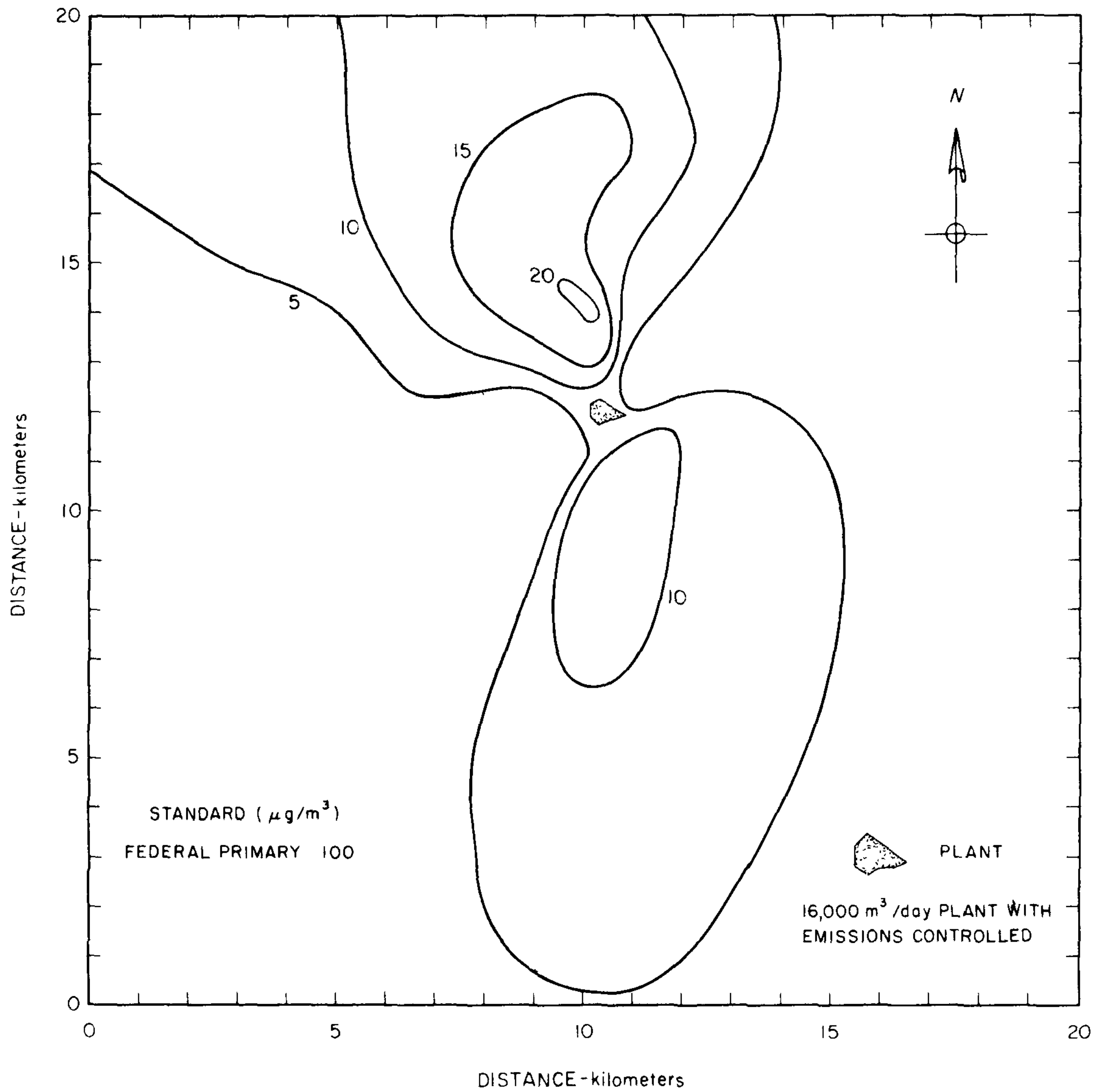

FIGURE 18 ANNUAL AVERAGE NO_X CONCENTRATION ($\mu g/m^3$) FOR A TOSCO II OIL SHALE PLANT USING SALT LAKE CITY, UTAH METEOROLOGY

Table 9

CONTROL REQUIREMENTS BASED ON FEDERAL PRIMARY AND COLORADO AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000 m^3/day (100,000 B/D) TOSCO II PLANT, CONTROLLED

Pollutant	Averaging Period	Maximum Calculated $\mu g/m^3$	Background* $\mu g/m^3$	Standard $\mu g/m^3$ Federal Primary	Standard $\mu g/m^3$ Colorado‡	Control Required† Federal Primary	Control Required† Colorado
Particulates	1 year	<34	<15	75	45	none	12%
	24 hours	377	15	260	-	35%	-
SO_2	1 year	18	<26	80	-	none	-
	24 hours	51	26	365	15	none	99+§
HC	3 hours (6-9am)	11	-	160	-	none	-
NO_x	1 year	23	-	100	-	none	-

*Based on preliminary Colony Development Operation data. Ongoing measurements suggest the 26$\mu g/m^3$ value is too high.

†Control required in addition to the best available as specified in Section IX.

‡Standards for non-designated areas of Colorado. The 24-hour standard is not to be exceeded more than one day per year.

§Background concentrations alone may exceed standard.

Table 10

CONTROL REQUIREMENTS BASED ON FEDERAL SECONDARY, CLASS I AND CLASS II AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000 m^3/day (100,000 B/D) TOSCO II PLANT, CONTROLLED

Pollutant	Averaging Period	Maximum Calculated	Background*	Standard: Federal Class I	Standard: Federal Class II	Standard: Federal Secondary	Control Required†: Federal Class I	Control Required†: Federal Class II	Control Required†: Federal Secondary
Particulates	1 year	34 $\mu g/m^3$	<15 $\mu g/m^3$	5 $\mu g/m^3$	10 g/m^3	60 $\mu g/m^3$	85%	71%	none
	24 hours	377	15	10	30	150	97	92	64%
SO_2	1 year	18	<26	2	5	-	89	72	-
	24 hours	51	26	15	100	-	71	none	-

*Based on preliminary Colony Development Operation data. Ongoing measurements suggest the 26 $\mu g/m^3$ value is too high.

†Control required in addition to the best available as specified in Section IX.

portion of the standard. When background concentrations equal or exceed a standard, the level of control has been specified as 99+ percent. The Federal Class I and Class II standards are the so-called "non-degradation" standards; they refer to increases in concentrations and do not involve background concentrations.

For particulates of the TOSCO II process, uncontrolled emissions will produce concentrations that exceed all standards listed in Tables 9 and 10, except the federal primary and secondary air quality standards. Background concentrations for particulates and SO_2 were measured in the Parachute Creek area of the Colorado oil shale region by the Colony Development Operation and analyzed in a report[6] by Dames & Moore. The median of the 24-hour averages of background concentration of particulates was found to be about 15 $\mu g/m^3$. The average annual background concentration is expected to be less than 15 $\mu g/m^3$. The combination of background concentrations with plant-produced concentrations for those standards for which this is applicable reveals the necessity for controls slightly in excess of 35 percent in order to meet the federal primary 24-hour standard. The Colorado annual standard requires 12 percent control. The federal 24-hour secondary standard can be met with approximately 64 percent control of plant emissions. Approximately 97 percent control will be needed to meet the Class I 24-hour standard and 85 percent will be needed to comply with the Class I annual standard. The Class II 24-hour and annual standards require 92 percent and 71 percent controls, respectively.

Projected concentrations of SO_2 do not exceed the federal primary air quality standards nor the Class II 24-hour standards. Dames & Moore found the 24-hour average background concentration of SO_2 to be 26 $\mu g/m^3$. The annual average is expected to be less than this amount. The addition of background concentrations to the calculated concentrations resulting from the plant is not sufficient to exceed the federal primary air quality standards. However, SO_2 concentrations from the plant exceed the stringent Colorado annual air quality standard, where 99+ percent control is required, since background concentrations alone may exceed the standard. The Federal Class I annual and 24-hour standards can be met with 89 percent and 71 percent control, respectively. The Class II annual standard requires 72 percent control.

No controls are required for HC and NO_x, since the concentrations of these pollutants are well below all applicable standards.

3. <u>In-situ Process</u>

Figure 3 (in Section IV) shows the stack configuration of a 16,000 m^3/day (100,000 barrel per day) in situ plant. The incinerator off gas release point shifts location from 1a to 1b to 1c during the 20-year life of the plant. Table 3 (in Section IV) lists the stack characteristics and emission rates used in concentration computations.

The results of modeling the air quality levels of an in situ oil shale plant are summarized in Tables 11 and 12 from production of 16,000 B/D and 100,000 B/D respectively. Projected annual and 24-hour average particulate levels do not exceed federal primary and secondary standards nor Colorado standards; therefore, no controls are required. The radical reduction of particulate levels for the in situ process, as compared to the TOSCO II process, can be attributed to the nature of subsurface retorting techniques. However, the Class I annual standard requires 29 percent control and the Class I 24-hour standard requires 76 percent control. The Class II annual standard requires no control and the Class II 24-hour standard can be met with 27 percent control.

Sulfur dioxide concentrations do not exceed the federal primary annual and 24-hour standards, regardless of the location of the incinerator. However, 99+ percent control is required to meet Colorado annual standards due to background concentrations, 78 percent

Table 11

CONTROL REQUIREMENTS BASED ON FEDERAL PRIMARY AND COLORADO AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000 m^3/day (100,000 B/D) IN SITU PLANT

Pollutant	Averaging Period	Maximum Calculated	Background	Standard: Federal Primary	Standard: Colorado	Control Required*: Federal Primary	Control Required*: Colorado
Particulates	1 year	7 $\mu g/m^3$	<15† $\mu g/m^3$	75 $\mu g/m^3$	45‡ $\mu g/m^3$	none	none
	24 hours	41	15†	260	-	none	
SO_2	1 year	9	<26†	80		none	
	24 hours	13	26†	365	15‡	none	99+§

*Control required beyond the relatively uncontrolled levels of emission estimated in Table 3.

†Based on preliminary Colony Development Operation data. Ongoing measurements suggest the 26 $\mu g/m^3$ value is too high.

‡Standards for non-designated areas of Colorado. The 24-hour standard is not to be exceeded more than one day per year.

§Background concentration alone may exceed standard.

Table 12

CONTROL REQUIREMENTS BASED ON FEDERAL SECONDARY, CLASS I AND CLASS II AIR QUALITY STANDARDS AND EMISSIONS FROM A 16,000 m^3/day (100,000 B/D) IN SITU PLANT

				Standard			Control Required*		
Pollutant	Averaging Period	Maximum Calculated	Background	Federal Class I	Federal Class II	Federal Secondary	Federal Class I	Federal Class II	Federal Secondary
Particulates	1 year	7 $\mu g/m^3$	<15 $\mu g/m^3$†	5 $\mu g/m^3$	10 $\mu g/m^3$	60 $\mu g/m^3$	29%	none	none
	24 hours	41	15†	10	30	150	76%	27%	none
SO_2	1 year	9	<26†	2	5	-	78%	45%	-
	24 hours	13	26†	15	100	-	none	none	-

*Control required beyond the relatively uncontrolled levels of emission estimated in Table 3.

†Based on preliminary Colony Development Operation data. Ongoing measurements suggest the 26 $\mu g/m^3$ value is too high.

control is needed to avoid violation of the Federal Class I annual standard and 45 percent control is required to meet the Class II annual standard. No controls are required for maintenance of the Federal Class I and Class II 24-hour standards. Concentrations of HC and NO_x from the in situ plant are well below the federal and Colorado standards, regardless of the noted changes in plant configuration.

It should be stressed that a stack's diameter, temperature and exit velocity have a great deal of influence on the concentrations resulting from the stack's emissions. A comparison of TOSCO II process and in situ process emissions and concentrations exemplify this influence. An inspection of Tables 2 and 3 (in Section IV) reveals that the total SO_2 emissions from the in situ plant are approximately three times the total SO_2 emissions from the TOSCO II plant, while the in situ concentrations are one-third to one-half of the TOSCO II concentrations. It was found that most of the in situ plant's SO_2 emissions are released from one stack, and the large diameter and temperature of that stack allow the pollutant to be mixed in a layer of sufficient depth so as to result in negligible ground-level concentrations. Since little contribution to ambient concentrations resulted from this stack, the concentrations appearing in Table 11 were produced by the remaining stacks. It should be noted, however, that changes in the stack characteristics of this source could drastically change SO_2 concentrations.

4. Complex of Plants

The preceding discussions of control levels applies to a single plant using a particular retort process. If more than one plant is present, the interaction of pollutant dispersion between the plants must be considered. To evaluate this interaction, the complex of plants, each with its own production level, stack characteristics and emission rates, should be modeled together. At the present time, sufficient information on the different oil shale recovery schemes and the planned configuration of plants is not available for a proper assessment of resulting pollutant patterns. The information available does not seem to warrant modeling a plant complex with the fine mesh of receptors necessary to resolve the pollutant distributions. However, on the basis of the modeling results for the TOSCO II and in situ plants, some recommendations can be made. The distances of maximum concentration for each pollutant and the rate at which the concentrations change with distance are the determining factors for effective plant placement. It is evident from an examination of the pollutant patterns shown in Figures 7 through 18 that plants situated in fairly close proximity can produce significantly higher concentrations than those arising from a single plant, particularly when one plant is directly downwind of another plant. A separation of 20 to 25 kilometers between plants should be sufficient to minimize any adverse effects arising from the interaction of each plant's pollutants.

The concentrations discussed above were computed assuming a 16,000 m^3/day (100,000 barrel per day) level of production. For other production levels, the concentrations should be multiplied by the appropriate factor and the required control adjusted accordingly. For example, concentrations should be reduced by one-half to obtain values for a 8,000 m^3/day (50,000 barrel per day) plant.

F. Recommendations

The above results for the oil shale region were obtained using a number of assumptions involving plant emission rates and configurations as given in Tables 2 and 3 and Figures 2 and 3 and the meteorology of Grand Junction, Colorado, and Salt Lake City, Utah. Changes in any of these variables could produce important differences in the predicted concentrations and, therefore, control requirements. Before definitive results can be obtained for a specific oil shale facility, the actual stack parameters and their emission rates for the proposed or existing plant should be obtained and sufficient meteorological information on the actual plant site should be gathered.

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VIII CONTROL REQUIREMENTS FOR AIR POLLUTANTS

In order to determine whether the emissions of air pollutants from the oil shale industry are likely to be excessive and, therefore, to require more control than appears available with the best current technology, we have compared the anticipated emissions with two different types of standards. The first is the ambient air quality standard. Comparisons with this type of standard have been presented in the preceding section (Section VII), where emissions from TOSCO II and in situ retorts were used to calculate ambient concentrations at ground level in the vicinity of a 16,000 m^3/day (100,000 barrels per day) plant. The second type of standard that can be used in an estimate of the need for air pollution control is the emission standard. This section of the report summarizes the findings of the previous section on ambient air quality and presents some relevant comparisons of emission standards.

Throughout this section control requirements are expressed in percent, meaning the percent of the emission that must be removed in order to achieve an ambient concentration or an emission level lower than the comparison standard. The control requirement derived here refers to the degree of control needed in addition to that achievable with best available control. The following section (Section IX) presents our findings as to what constitutes best available control applied to the TOSCO II retorting system proposed and described by the Colony Development Operation.[1]* As defined in Section IX, best available controls lead to emission streams with particulate loadings less than 46 mg/m^3 (0.02 gr/SCF) and emissions of combustion gases that meet the new source performance standards for fossil fuel fired boilers. The proposed Colony plant is the basis for

*Numbers refer to references given at the end of this section.

the discussion of control requirements in this report, the only exception being use of an in situ plant for some of the work reported in the preceding section (Section VII).

The control requirements derived from dispersion modeling and comparison with ambient air quality standards are summarized in Table 13. The multiplicity of possible standards leads to the multiple estimates of control requirements. The implication of Table 13 and the supporting work in Section VII is that significant additional control may be needed to prevent the violation of some of the very strict ambient air quality standards for particulates and SO_2 in the vicinity of a 16,000 m^3/day (100,000 barrels per day) oil shale plant using the TOSCO II process.

It should be pointed out that the maximum requirements for additional control summarized in Table 13 are not necessarily requirements for improved technology for removing pollutants from emission streams. Some of the maximum values given in Table 13 are based on maximum concentrations calculated to occur quite close to some of the relatively low stacks of the proposed plant. While details of this phenomena are apparent only through an examination of a number of calculations using different stacks, stack locations, and stack heights as inputs, the effect is clearly displayed in some of the figures presenting results of the dispersion modeling in Section VII. Figures 10 and 14 are significant examples of this effect and the implications for deriving control requirements. In both of these cases, a high concentration of the pollutant occurs next to a low (only 15 meters high) stack because winds will bring some of the pollutant to the ground right at the stack. Because this problem can be solved by use of moderate height stacks (about 50 meters), it should not be made the basis of a requirement for additional emission stream clean-up.

The same logic does not apply, however, to avoiding excessive ground level concentrations associated with taller stacks. The implication of

Table 13

ESTIMATES OF ADDITIONAL CONTROL REQUIREMENTS FOR A 16,000 m^3/day (100,000 B/D) TOSCO II PLANT BASED ON DISPERSION MODELING AND VARIOUS AMBIENT AIR QUALITY STANDARDS

Pollutant	Maximum Control Requirement for Standard Indicated*				
	Federal Primary	Federal Secondary†	Colorado	"Non-degradation Standards" Class II	Class I
Particulate	35%	64%	12%	92%	97%
SO_2	none	NA	99+%‡	72%	89%
HC	none	NA	NA	NA	NA
NO_x	none	NA	NA	NA	NA

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* More detail is presented in Tables 9 and 10 and their accompanying text in Section VII. See also the text in this section.

† The Federal Secondary standards apply in Class III regions under the "non-degradation" rules proposed by EPA.

‡ Background concentration alone could exceed the standard in some locations.

NA indicates that an estimate is not applicable because the appropriate comparison standard does not exist.

the EPA position limiting the use of tall stacks to control air pollution from electric power plants would suggest that stacks more than 100 meters (very approximately) should not be considered acceptable means of air pollution control for an oil shale plant. The stacks in question here could be made considerably higher without exceeding likely EPA restrictions on stack heights deemed suitable for inclusion in an air pollution control system for such a facility. Further clarification concerning the use of tall stacks will depend upon the generation of definitive data regarding sulfates and chemical transformations in the atmosphere.

A comparison of Figure 14 with Tables 9 and 10 will show that the concentration chosen for calculating the SO_2 control requirements is the $51 \mu g/m^3$ level that occurs over 5 km from the plant rather than the very much higher level (perhaps $900 \mu g/m^3$) that is calculated for a small area within the plant itself. On the other hand, the maximum particulate concentration of $377 \mu g/m^3$ shown in Figure 10 is used as a basis for deriving control requirements in Tables 9 and 10, despite the fact that it occurs very close (about 0.5 km) to the plant and must reflect a significant contribution that could be removed by increasing the height of the lowest stacks. In this latter case, there is no obvious alternative level of concentration on which to base a control requirement. The summary table that concludes this section presents control requirements that reflect our judgment on this matter.

The estimation of control requirements on the basis of emission standards must be carried out under the assumption that emission standards set for other industries can be applied to the oil shale industry. The sources of significant quantities of emissions from oil shale processing will be new plants. Therefore, it is appropriate that the emission standards applied be new source performance standards. In the absence of such standards for the oil shale industry itself, we have sought analogies elsewhere. It appears that the developers of oil shale tend to make comparison to the standards for emissions from utility boilers, and that these comparisons are made on the basis of weight of pollutant per unit of energy consumed in the process. Such a comparison is presented in Table 14.

Not all the emissions of the three pollutants are included in Table 14. Only those emissions that are produced in combustion processes are included, because only these are logically comparable to the fossil fuel boiler case. This point is especially significant with respect to the particulate emission because less than a tenth of the total particulate emissions from a TOSCO II plant having "best controls" are included in the category of emissions from the combustion process itself. Over 90 percent of the particulate emissions are from processes other than pure combustion, namely, from the shale handling, shale heating, and ball cleaning operations shown in Figure 21 and Tables 16 and 19 of Section IX. The pure combustion processes are those listed in Table 20 as associated with product upgrading. Therefore, the implication of Table 14 that no additional control of particulate emissions is required is not inconsistent with the results of the air quality modeling of Section VII.

The conclusions to be drawn from the comparison of combustion emission factors in Table 14 are as follows: (1) no additional control is required on particulate emissions due directly to the combustion of fuel to fire the retort; (2) about 20 percent additional control is required in the combustion process to bring the SO_2 emissions into compliance with analogous emission standards for oil fired fossil fuel boilers; (3) nearly 95 percent control of NO_x is required to bring the combustion of fuel oil into compliance with analogous emission standards for oil fired fossil fuel boilers. The table also suggests that much, but certainly not all, of this additional control requirement for NO_x can be met by making maximum use of gas and butane (C_4 liquids) fuels produced along with the shale oil.

Table 14

EMISSIONS FROM COMBUSTION IN THE TOSCO II PROCESS COMPARED WITH FEDERAL STANDARDS FOR UTILITY BOILERS

Pollutant (and fuel burned*)	Emission Factors in Weight per Energy Consumed			
	Emission Factor (kg/GJ)		Emission Factor (lb/10^6 Btu)	
	TOSCO II†	Standard‡	TOSCO II†	Standard‡
Particulates (gas)	0.007	0.0043	0.017	0.1
Particulates (C_4)	0.009	0.043	0.02	0.1
Particulates (oil)	0.045	0.043	0.11	0.1
SO_2 (gas)	0.22		0.51	
SO_2 (C_4)	0.06	0.35	0.14	0.8
SO_2 (oil)	0.43	0.35	1.00	0.8
NO_x (gas)	0.37	0.087	0.85	0.2
NO_x (C_4)	0.39	0.130	0.91	0.3
NO_x (oil)	2.09	0.130	4.85	0.3

* The TOSCO II plant can burn any one of three fuels produced from the oil shale: a fuel gas, a butane fuel (C_4 compounds), or a fuel oil.

† Source: Colony Development Operation, Reference 1.

‡ Source: EPA new source performance standards for fossil fuel boilers, The Federal Register, 23 December 1971.

The findings presented in this section and the preceding one, Section VII, indicate a wide range of quantitative estimates of control requirements, depending primarily on the choice of comparison standard. The table just presented, Table 14, provided an emission standard comparison for estimating requirements for controls beyond those planned for Colony's TOSCO II plant. Our estimates for control required beyond the best available control case presented in the following section, Section IX, are given in Table 15. These control requirements are derived from the dispersion modeling (Section VII) applied to the emissions of the "best available control" case presented in Section IX. No need for additional control beyond the best available is indicated for hydrocarbons and oxides of nitrogen. A range of control requirements is indicated in Table 15 for both particulates and sulfur dioxide. These are the ranges we consider to be reasonable, as explained below.

The range of estimated control requirements has been narrowed from the extremes that can be found in the preceding tables of this section and Section VII by making the following assumptions, which we take to be reasonable: (1) because the oil shale region now enjoys a minimum of air pollution, it is unlikely that air quality there will be allowed to be degraded to the most lenient standard. Hence, the federal primary ambient air quality standards are ruled out; (2) if a significant oil shale industry is allowed to come into being in western Colorado, the region will not be classified as one where the most strict non-degradation standards will be applied. Hence, the Class I federal and the most strict Colorado (i.e., the $15 \mu g/m^3$ 24-hr. SO_2) air quality standards are ruled out; and (3) to compensate for local effects of unnecessarily low (about 15 m) stacks only concentrations applicable over areas more than one square kilometer in size and more than one km in distance from the plant are used for quantifying control requirements. Hence, the calculated maximum concentration of particulates for the 24-hour worst case is taken as $200 \mu g/m^3$ rather than the $377 \mu g/m^3$ peak used in Tables 9, 10 and 13.

Table 15

RANGE OF REASONABLE REQUIREMENTS FOR CONTROL BEYOND BEST AVAILABLE FOR A 16,000 m^3/day (100,000 B/D) TOSCO II OIL SHALE PLANT

Pollutant	Extreme	Control Requirement Percent	Basis for the Control Requirement: Calculated Concentration $\mu g/m^3$	Averaging Time	Standard: Level $\mu g/m^3$	Type
Part.	Max.	85	200	24 hours	30	Class II
	Min.	33	200	24 hours	135*	Fed. Sec.
SO_2	Max.	72	18	1 year	5	Class II
	Min.	none	50	24 hours	100	Class II
HC	-	none	11	3 hours	160	Fed. Pri.†
NO_x‡	-	none	23	1 year	100	Fed. Pri.†

*Reduced by 15$\mu g/m^3$ for background concentration.

†Federal Primary is the only comparison air quality standard.

‡Emission factor may exceed the best available, i.e., the new source performance standard for oil fired boilers.

The conclusions in Section I regarding requirements for control of oil shale air pollution beyond the best available control case are drawn from Table 15 and the discussion presented in this section to explain and justify the values adopted in Table 15.

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IX ASSESSMENT OF AIR POLLUTION CONTROL METHODS

A. Introduction

As described in Sections IV and V of this report, the TOSCO II retorting process seems likely to dominate the oil shale industry at least in the early stages of industry growth. This process is the only one for which emissions figures are available on a unit operation basis. These considerations have led SRI to adopt this process as representative of the industry for purposes of estimating emissions. It will be seen that certain elements of the process will be common to other above-ground retorting methods, while other elements are unique to TOSCO II. These distinctions will be discussed so that an appreciation for the degree to which conclusions depend on this choice may be gained.

The data on the TOSCO II process are taken from the Environmental Impact Analysis[1*] published by the Colony Development Operation. The Atlantic Richfield company (ARCO) is the operator for the group of companies that comprise Colony. The shale oil complex planned by Colony incorporates certain control devices and methods that are considered by the operator to be adequate to ensure that appropriate federal and state standards are met. No claim is made by the operator that "best control" is achieved, or that a complex of plants like the Colony operation in the same vicinity would not violate appropriate standards. The objective in this section of the study is to ascertain how effective the applied controls are, and to estimate what degree of control may reasonably be expected in an effort to apply best available control to the system described by Colony. The estimate of these limits will help in the assessment of the impact of a developing industry, and will help define the need for improved control technology.

*References are listed at end of section.

A definitive, detailed engineering analysis of all process streams and potential control methods comparable to the effort extended by the operator and his contractors responsible for designing controls systems is far beyond the scope of this study. In any event, important details of various process steps are considered proprietary and not available for our examination. In spite of these facts, the available data are adequate for a model and several useful conclusions may be drawn concerning emissions control. The selection of control methods is intimately bound to process economics, a particularly proprietary matter. Hence, it is assumed that the kind of device selected for a particular application is the appropriate choice, but not necessarily that it is operated at maximum effectiveness. Where control remains inadequate at maximum effectiveness, further development would be necessary. Where alternative controls were considered by the operator, these are discussed. In other words, redesign of the TOSCO II process as implemented by Colony is not attempted.

For each of the major process steps in the Colony design the emissions are estimated assuming "best control" is applied. These judgments are based on familiarity with the types of control equipment specified by Colony and with the performance that can be expected at what is judged a reasonable cost. Specific, quantitative estimates of best control are given in this section for each unit of the process. Control performance is conservatively estimated in that better performance has been achieved in limiting cases. Where improved control is achieved with cleaner fuels, the assumptions underlying the "best control" case are clearly stated. However, it must be emphasized that the plans for the fuels to be used are only tentative in any case.

In addition to the data in the Environmental Impact Analysis, some data gained in personal communication with representatives[2] of

Colony were useful in the study. This assistance is gratefully acknowledged.

B. Description of Process

A detailed description of process streams for the TOSCO II process is given in Section IV. A modular description is presented here so that elements common to other retorting methods can be identified and the emissions for each module can be characterized. A simplified process diagram for any above-ground retorting plant is given in Figure 19.

In the ore-preparation module shown in Figure 19 the run-of-mine ore is reduced to a maximum size compatible with the retorting method. A sufficient quantity of ore in the various stages of preparation is placed in storage to guard against interruptions in mine output or crushing equipment failures. The only emission of consequence here is dust--fugitive dust from the transport and storage of the ore and dust generated in the crushing operation. The magnitude of these emissions depends in part on the fineness of the feed required by.the oil shale plant, but may be unprecedented in magnitude because of the vast quantity of material to be handled.

In the retorting module shown in Figure 19 the ore is converted to a useful hydrocarbon product plus a shale ash to be discarded. The emissions to the atmosphere from this module vary greatly in kind depending on the retorting method. Products of combustion are always present, and these may be mixed with process constituents in some retorts. Control problems in this module may be unique to oil shale processing or to specific retorts. In the TOSCO II process, for example, flue gases are loaded with dust and hydrocarbons from direct contact with the shale. Control problems are compounded by the large quantities of effluent to be treated. Most of the fuel consumed in a

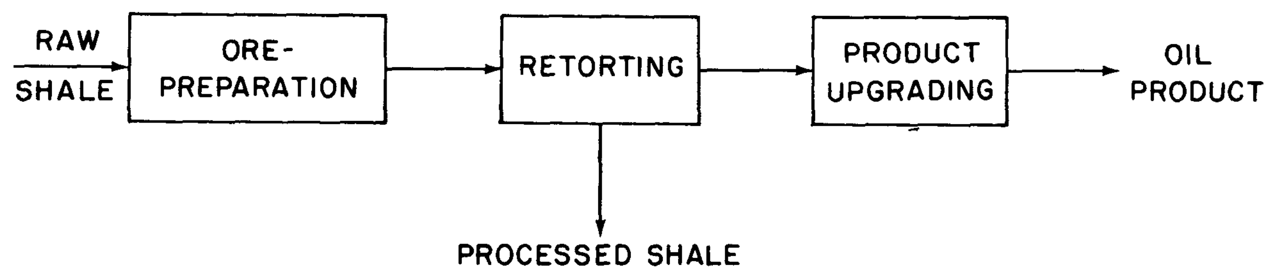


FIGURE 19 SIMPLIFIED PROCESS DIAGRAM — —
ABOVE-GROUND RETORTING PLANT

plant is consumed in this module. Finally, shale ash disposal presents dust control problems for any retort.

In the product-upgrading module shown in Figure 19, the hydrocarbon product from the retort is further processed into a more useful form. Emissions in this module consist of combustion products plus sulfur dioxide resulting from removal of sulfur compounds from the process streams. None of these emissions is unique to oil shale processing.

C. Emissions and Controls

The emissions estimated and controls planned by the Colony Development Operation[1] for a TOSCO II plant are now considered in some detail. The Colony plant would produce 8,000 m^3/day (50,000 barrels/day) of product. The present estimates are made for a hypothetical plant twice that size.

The ore-preparation system is indicated schematically in Figure 20. The primary crusher reduces the ore to a maximum size of about 23 cm (9 in), and this is further reduced in the final crusher to less than 1.25 cm (1/2 in). Dust control at these sites and at the fine ore storage facility is maintained with a baghouse. Estimates of emissions and control performance are given in Table 16.

The estimates of "Emissions Without Control Devices" were not given directly by Colony, but were deduced by SRI from the values given for disposal of dust from these control points and from the stated flow rates. The "Emissions Remaining With Planned Control" shown are as given by Colony. From these values the "Device Efficiency" shown is calculated. SRI estimates that a dust loading not exceeding 46 mg/m^3 (.02 gr/ACF) is an achievement reasonable to expect in a well maintained baghouse. Higher performance might be achieved, but this conservative estimate serves as a base to calculate the "Emissions Remaining With Best Control"

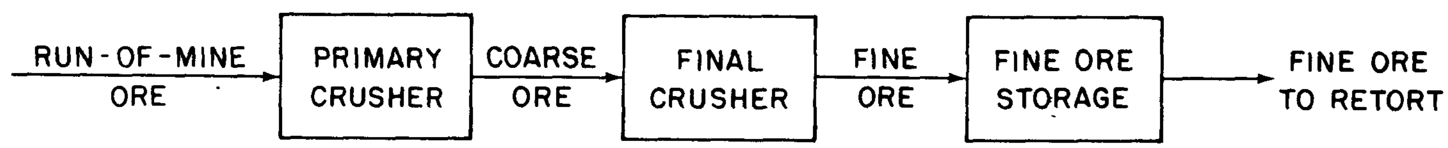


FIGURE 20 ORE- PREPARATION SYSTEM FOR TOSCO II PLANT

Table 16

ORE-PREPARATION SYSTEM EMISSIONS FOR TOSCO II PLANT (16,000 m^3/day)

	Estimated Emissions Without Control Devices			Control Methods		Emissions Remaining With Planned Control		Efficiency With Best Control	Emissions Remaining With Best Control	
Subsystem	Type	(mg/m^3)	(kg/hr)	Device or Other Method	Device Efficiency (percent)	(mg/m^3)	(kg/hr)	(percent)	(mg/m^3)	(kg/hr)
Primary Crusher	Part.	2,290	1,944	Baghouse	97.22	64	54	97.99	46	39
Final Crusher	Part.	26,100	26,730	Baghouse	98.98	268	272	99.82	46	47
Fine Ore Storage	Part.	21,100	5,724	Baghouse	99.06	202	54	99.79	46	12

and "Efficiency With Best Control." The resulting values for efficiency appear quite reasonable.

Various sources of fugitive dust remain in the ore-preparation system planned by Colony, even after the provision for enclosures surrounding transport and processing equipment. The most important potential source is the stockpile of coarse ore from the primary crusher. Control is maintained with water sprays, and the planned site is selected to minimize the surface area exposed to the wind. The magnitude of this problem will depend directly on the detailed topography of the stockpile, which is constantly changing in normal operation, and the persistence in applying a water spray. In the absence of detailed assumptions, estimates have little meaning. However, it seems reasonable to assert that sufficient spraying can be applied to effectively suppress dust levels below those resulting from the sources listed in Table 16.

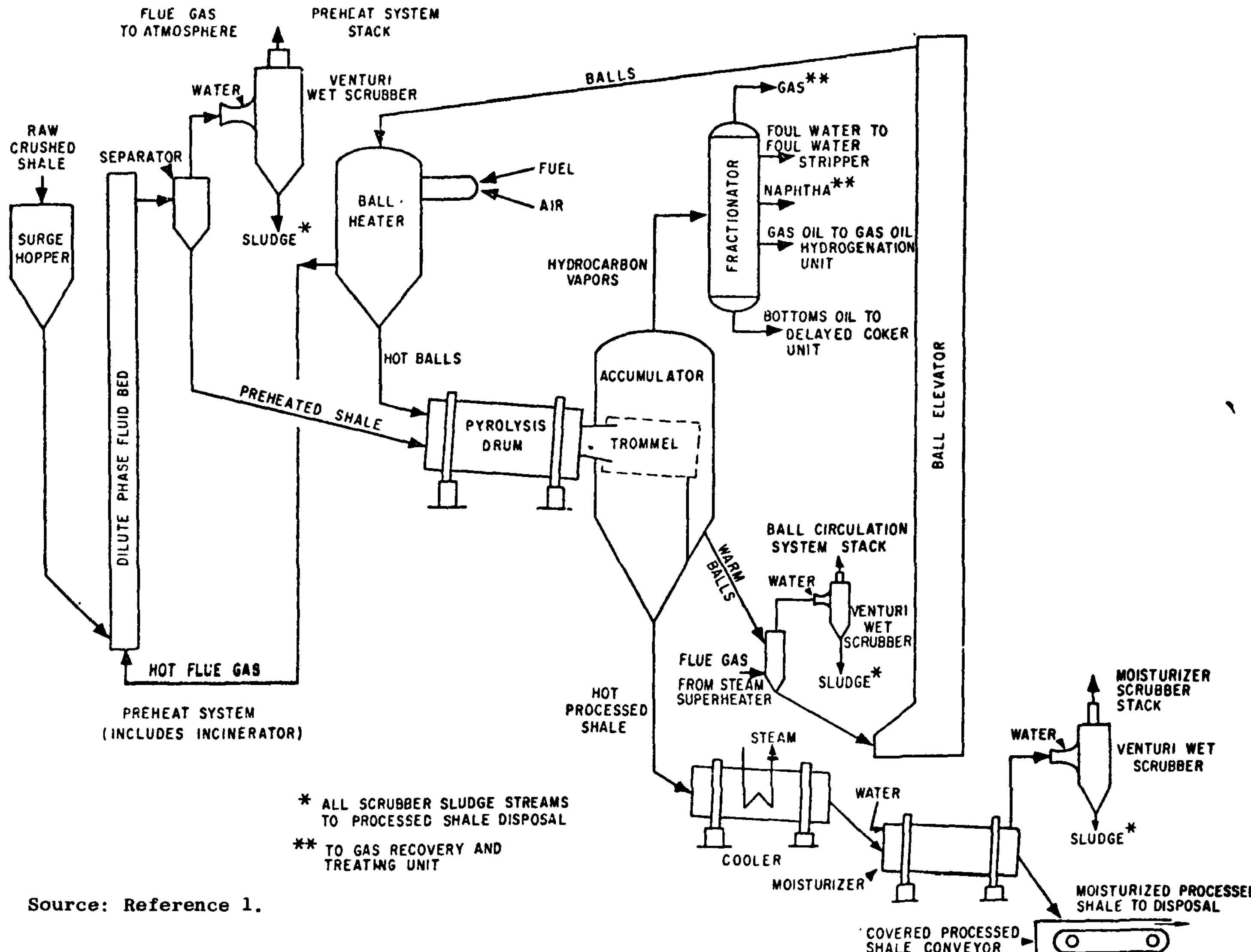
The pyrolysis and oil recovery unit for the TOSCO II process is shown schematically in Figure 21. This unit is analogous to the retorting module in Figure 19. The majority of each type of pollutant emitted from a TOSCO II plant is emitted from this unit. About two-thirds of all combustion takes place here, and the shale is further crushed very finely in the pyrolysis drum.

Colony plans to use only process fuels for combustion. Three distinct fuels will be used--fuel gas, C_4 liquids (butanes and butenes), and a distillate fuel oil. All the fuel gas and C_4 liquids produced will be consumed. The remaining needs will be made up with the fuel oil. A complicated fuel system provides various combinations of fuels to furnaces equipped with multiple burners. The proportions will be highly variable during normal plant operation. A typical consumption schedule for the plant is given in Table 17 and is the basis for emission rates presented below in Tables 19, 20, and 21.

The fuel gas and C_4 liquids are treated in the gas recovery and treating unit to remove hydrogen sulfide. The fuel oil could be gas oil or naptha (see Fractionator in Figure 21) or a blend of the two. Colony plans to use gas oil before upgrading and removal of moderate sulfur and high nitrogen content. The maximum emission rates for these three fuels as specified by Colony are given in Table 18, along with the federal performance standards for new power plants for comparison.

Estimates of emissions from the pyrolysis and oil recovery unit using these fuels are given in Table 19. The raw shale preheat system consumes nearly all the fuel supplied to this unit. Hot flue gases from the ball heater contact the raw crushed shale directly in a fluidized bed, adding particulate and hydrocarbon loads to the combustion products. An incinerator reheats the flue gases and reduces the hydrocarbons volatilized in the fluidized bed. The bail circulation system uses flue gases from the steam super-heater to remove residual, processed-shale dust. Dust removal is accomplished with dry cyclones followed by venturi wet scrubbers. The processed-shale moisturizing system emits only particulates in the form of processed-shale dust, controlled with a venturi wet scrubber.

The values given for particulate emission in Table 19 were deduced or calculated as in Table 16. An exception is the Emissions Remaining With Planned Control of particulates in the raw shale preheat system. The emission rate and loading values given by Colony seemed to be inconsistent. The loading value, consistent with SRI estimates of performance reasonably to be expected, was accepted and used to calculate an emission rate nearly double the Colony value. This same loading value, 46 mg/m^3 (.02 gr/ACF), is the basis for the SRI estimate of Emissions Remaining With Best Control for the other scrubbers in this unit.



Source: Reference 1.

Figure 21. PYROLYSIS AND OIL RECOVERY UNIT FOR TOSCO II PLANT

Table 17

TYPICAL FUEL CONSUMPTION SCHEDULE FOR TOSCO II PLANT* (16,000 m^3/day)

Source	Fuel Gas $10^9 J/hr$	C_4 Liquid $10^9 J/hr$	Fuel Oil $10^9 J/hr$
Pyrolysis and oil recovery unit			
Raw shale preheat	1494	810	1593
Steam superheater--ball stack		304	
Hydrogen unit	1334		
Naphtha hydrogenation unit	21		
Gas oil hydrogenation unit			
Feed heater		99	
Fired reboiler		84	
Delayed coker unit	186		
Utility boilers			196
Sulfur plant	21		
TOTALS	3056	1297	1789

*It should be emphasized that while estimates of total fuel consumption are subject to only minor revisions, the allocation of fuels to various sources is quite preliminary, and is not only subject to substantial revision, but will be variable during plant operations.

Source: Reference 1.

Table 18

EMISSION FACTORS FOR TOSCO II PLANT PLANNED FUELS

Pollutant	Fuel	TOSCO II (Colony) $(kg/10^{10}J)$	TOSCO II (Colony) $(lb/10^6Btu)$	Comparison Federal Performance Standard (New power plants)* $(kg/10^{10}J)$	Comparison Federal Performance Standard (New power plants)* $(lb/10^6Btu)$
Particulates	Fuel gas	.073	.017	.43	0.1
	C_4 liquid	.086	.02		
	Fuel oil	.452	.105	.43	0.1
SO_2	Fuel gas	2.2	.51		
	C_4 liquid	.60	.14		
	Fuel oil	4.3	1.0	3.4	0.8
NO_x	Fuel gas	3.7	.85	.86	0.2
	C_4 liquid	3.9	.91		
	Fuel Oil	20.9	4.85	1.3	1.3

*Comparison values for natural gas are used for the fuel gas.

Source for TOSCO II factors: Reference 1.

Table 19

PYROLYSIS AND OIL RECOVERY UNIT EMISSIONS FOR TOSCO II PLANT (16,000 m^3/day)

Subsystem	Type	Emissions Without Control Devices: Amount (1)	Emissions Without Control Devices: Amount (kg/hr)	Control Methods: Device or Other Method	Control Methods: Device Efficiency (percent)	Emissions Remaining With Planned Control (1)	Emissions Remaining With Planned Control (kg/hr)	Efficiency With Best Control (percent)	Emissions Remaining With Best Control (1)	Emissions Remaining With Best Control (kg/hr)
Raw shale preheat	Part.	15,600	65,000	Scrubber	99.71	46	190	99.71	46	190
	SO_2	2.7(140)	1,060	(2)	(2)	2.7(140)	1,060	(3)	2.4(122)	925
	NO_x	10.7	4,180	-	-	10.7	4,180	(3)	2.8	1,070
	HC	-	-	Incinerator	-	90	272	-	90	272
Steam super-heater--ball stack	Part.	5,860	5,118	Cyclone/scrub.	95.74	250	218	99.18	46	40
	SO_2	.60(11)	19	(2)	(2)	.60(11)	19	-	.60(11)	19
	NO_x	3.9	119	-	-	3.9	119	-	3.9	119
Processed shale moisturizer	Part.	8,180	3,495	Scrubber	92.99	570	245	99.38	46	20

(1) Units: Particulates, mg/m^3; SO_2, kg/10^{10}J(ppm by vol); NO_x, kg/10^{10}J; HC, ppm by weight.

(2) Control obtained with treated fuels; see Tables 17 and 18.

(3) Increased control obtained by substitution of fuel oil meeting minimum emission standards for new power plants in place of planned fuel oil; see Tables 17 and 18.

Table 20

PRODUCT-UPGRADING SYSTEM EMISSIONS FOR TOSCO II PLANT (16,000 m^3/day)

Subsystem	Type	Emissions Without Control Devices Amount (1)	Emissions Without Control Devices Amount (kg/hr)	Control Methods: Device or Other Method	Control Methods: Device Efficiency (percent)	Emissions Remaining With Planned Control (1)	Emissions Remaining With Planned Control (kg/hr)	Efficiency With Best Control (percent)	Emissions Remaining With Best Control (1)	Emissions Remaining With Best Control (kg/hr)
Hydrogen	Part.	9	9.7	-	-	9	9.7	-	9	9.7
unit	SO_2	2.2(240)	291	(2)	(2)	2.2(240)	291	-	2.2(240)	291
	NO_x	3.7	487	-	-	3.7	487	-	3.7	487
Naphtha	Part	7	.18	-	-	7	.18	-	7	.18
hydrog.	SO_2	2.2(200)	4.5	(2)	(2)	2.2(200)	4.5	-	2.2(200)	4.5
	NO_x	3.7	8.2	-	-	3.7	8.2	-	3.7	8.2
Gas oil	Part.	7	.82	-	-	7	.82	-	7	.82
hydrog: feed	SO_2	.60(55)	6.4	(2)	(2)	.60(55)	6.4	-	.60(55)	6.4
heater	NO_x	3.9	39	-	-	3.9	39	-	3.9	39
Fired	Part.	7	.73	-	-	7	.73	-	7	.73
reboiler	SO_2	.60(60)	5.4	(2)	(2)	.60(60)	5.4	-	.60(60)	5.4
	NO_x	3.9	33	-	-	3.9	33	-	3.9	33
Delayed	Part.	9	1.4	-	-	9	1.4	-	9	1.4
coker	SO_2	2.2(230)	41	(2)	(2)	2.2(230)	41	-	2.2(230)	41
	NO_x	3.7	68	-	-	3.7	68	-	3.7	68
Utility	Part.	50	8.9	-	-	50	8.9	-	50	8.9
boilers	SO_2	4.3(450)	84	(2)	(2)	4.3(450)	84	(3)	3.4(360)	67
	NO_x	20.9	409	-	-	20.9	409	(3)	1.3	25
Sulfur plant	SO_2	(4-5,000)	1,160	Beavon or Cleanair	95.0	(250)	58	-	(250)	58

(1) Units: Particulates, mg/m^3; SO_2, $kg/10^{10}J$ (ppm by vol); NO_x, $kg/10^{10}J$

(2) Control obtained with treated fuels; see Tables 17 and 18.

(3) Increased control obtained by substitution of fuel oil meeting minimum emission standards for new power plants in place of planned fuel oil; see Tables 17 and 18.

Table 21

TOTALS OF EMISSIONS FOR TOSCO II PLANT (16,000 m^3/day)

Emissions Without Control Devices		Control Methods		Emissions Remaining With Planned Control	Efficiency With Best Control	Emissions Remaining With Best Control	Ambient Air Quality Comparisons*		Additional Control Requirement
Type	Amount (kg/hr)	Device or Other Method	Device Efficiency (percent)	(kg/hr)	(percent)	(kg/hr)	Calculated from Best Control Case ($\mu g/m^3$)	Class II Standard ($\mu g/m^3$)	(percent)
Part.	107,700	Baghouse, Cyclone, Scrubber	99.02	1055	99.66	370	200	30	85
SO_2	2,671	Treated fuels, Tail-gas	41.26	1569	46.95	1417	18	5	72
NO_x	5,343	-	-	5343	65.39	1849	23	100**	none
HC	-	Incinerator	-	272	-	272	11	160**	none

*Based on Table 15 and its accompanying text in Section VIII.

**Federal Primary Standard. No Class II standard exists.

The basic control method for SO_2 planned by Colony consists of the use of treated fuels. Flue-gas desulfurization was considered by Colony and judged to be more expensive and less reliable. Colony has indicated that if the emissions of SO_2 must be reduced for the plant, a treated fuel would be used to replace the planned fuel oil in the proportion necessary to meet requirements. The cost for this was estimated at "approximately one-eighth of a barrel of low sulfur fuel oil product . . . per barrel of 'treated' fuel oil burned."[1] The characteristics of such a treated fuel oil were not specified; however, both SO_2 and NO_x emissions could be reduced by additional hydrogenation of the fuel oil. This hydrogenation would remove sulfur as H_2S and nitrogen as NH_3. In practice the nitrogen is harder to remove than the sulfur, so that reducing the relatively high nitrogen content in the fuel oil to lower levels would result in even greater reduction of the sulfur level. However, for purposes of defining best available control, SRI has assumed that the treated fuel oil could meet the federal performance standards for oil fired boilers shown in Table 18. The substitution of this treated fuel oil results in the SO_2 and NO_x Emissions Remaining With Best Control shown in Table 19. It is seen that the NO_x emission is substantially reduced with this substitution. The SO_2 emission must be regarded as an upper limit, since hydrotreatment is more effective on sulfur as described above.

A major cost consideration for Colony regarding flue-gas desulfurization is related to the large (125 to 150 percent) excess-air firing in the shale preheat system where nearly all the fuel oil is combusted. This practice, done for process reasons, results in much larger quantities of effluent to be treated and correspondingly larger capital and operating costs. Nonetheless, should greater control of SO_2 emissions be required to meet a standard, flue-gas desulfurization is certainly an option to be considered and compared in cost with additional hydrotreatment. Flue-gas desulfurization equipment appears to be capable of meeting the additional control requirement shown in Section VIII and in Table 21 above.[3]

Estimates of emissions from the remainder of a TOSCO II plant are given in Table 20. These units comprise the product-upgrading module shown in Figure 19, and would be similar for any retort producing a similar product. Emissions result from the combustion of treated fuels, as examined above, and from the operation of the sulfur plant. The performance of the specified tail-gas treating plants is considered to be a reasonable estimate.

Finally, Table 21 shows the totals of emissions of each type listed in Tables 16, 19, and 20. This table is intended to be an indication of overall performance showing planned controls and, with reasonable assumptions, limits of best available control using the same basic scheme.

D. Estimates for Other Retorting Schemes

The emissions estimates for ore-preparation modules would be similar to those given in Table 16 for any retorting method requiring a maximum size of 1.25 cm (1/2 in). Furthermore, it is seen that the emission rates, for both primary and final crusher are approximately the same in spite of the size difference. A reasonable estimate for any retort accepting a large-size feed of about 20 cm (8 in) would be that for the primary crusher, and for a retort requiring a substantially smaller size the total for both crushers would be a reasonable estimate. The estimate for ore storage could be used for either case.

Emissions from a retorting module could differ significantly from the estimates in Table 19. Particulate and hydrocarbon emissions from the raw shale preheat system and ball stack system result from the specific design of TOSCO II. These could be absent in other retorts, except for relatively insignificant particulate emissions from the combustion. The estimate for the processed-shale moisturizer should serve as an upper limit for other retorts where the shale has not been so finely crushed.

Estimates of SO_2 and NO_x emissions in the retorting and product-upgrading modules depend primarily on the sulfur and bound-nitrogen content in the process fuels and the total quantities combusted. Under present conditions, hydrotreating the process fuels is the likely control method due to the nature of the plant and respective costs. Again, if further reduction of SO_2 emissions is required after hydrotreatment, flue-gas desulfurization could be applied. Unlike the operation planned by Colony, process restrictions may not exist to make flue-gas desulfurization more difficult. Even other TOSCO II installations could differ with regard to the fuels planned, especially for the shale-preheat system.

The emission of SO_2 from the sulfur plant depends primarily on the total output of low-sulfur product, but is small relative to combustion emissions.

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3. Proceedings: Flue-Gas Desulfurization Symposium--1973, EPA-650/ 2-73-038, December 1973.

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Colony. Requirements for additional control are estimated by comparing calculated ambient air quality with standards. Options for supplying the additional control indicated for particulates and sulfur dioxide are identified.

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

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20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

This study evaluates the air pollution potential of emissions of particulates, sulfur dioxide, oxides of nitrogen, and hydrocarbons from the anticipated development of an oil shale industry. The analysis is based primarily on the published description of a TOSCO II retorting process as planned for commercial use by the Colony Development Operation. The technology, processes, plans, projections, and environmental impacts of oil shale development are reviewed. The results of dispersion model calculations of concentrations of pollutants in ambient air near oil shale plants employing TOSCO II and in situ processes are presented. These calculations for the TOSCO II plant assume that best available controls are applied to the process planned by

(continued under No. 18)

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