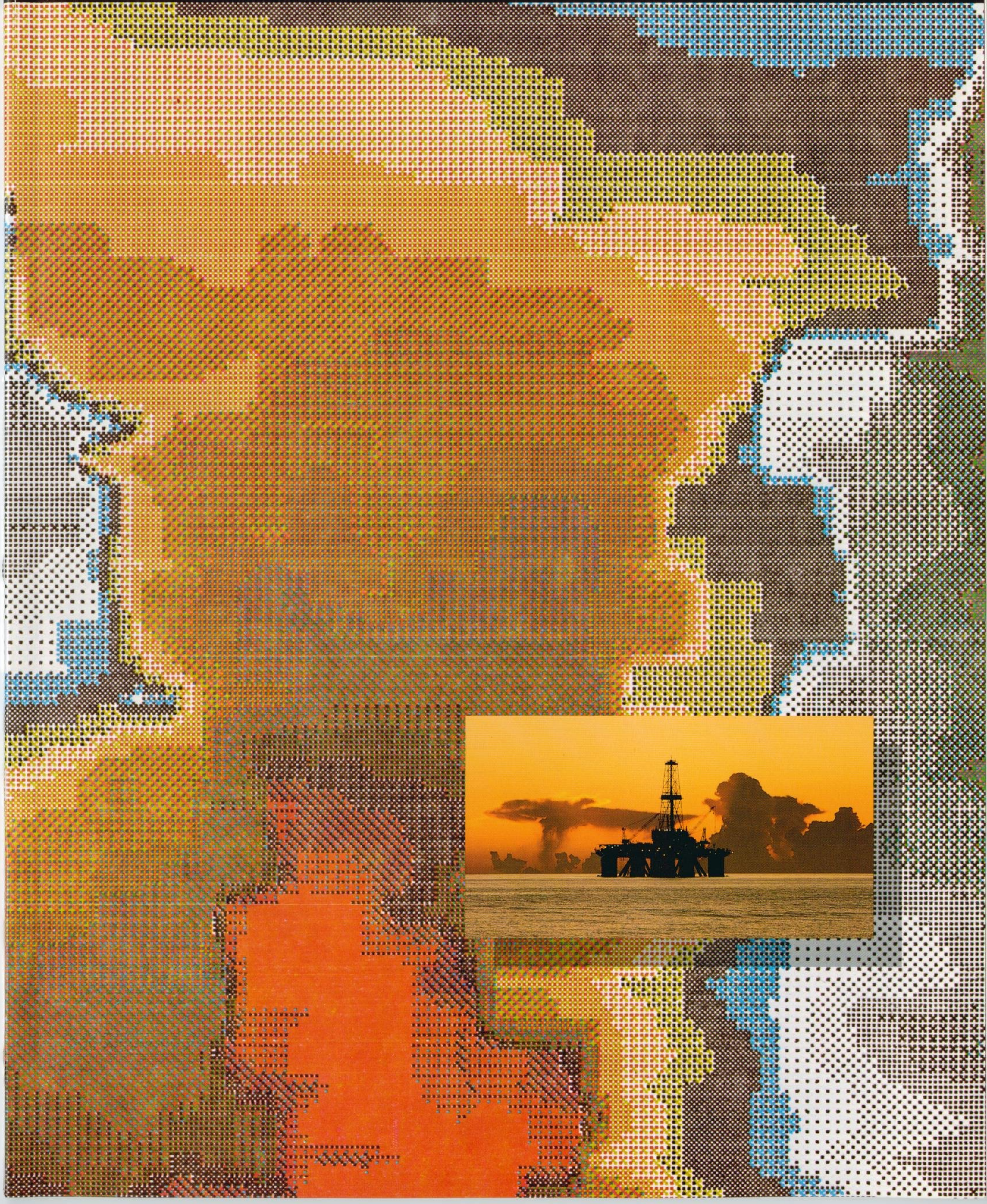
Exhibit A and Appendices 1.1A and 3.4A. Volume V

EXXON

EXXON CORPORATION 1984 ANNUAL REPORT



Exxon Corporation
1251 Avenue of the Americas
New York, New York 10020-1198
Telephone: (212) 333-6900

Divisions and affiliated companies of Exxon Corporation operate in the United States and over 80 other countries. Their principal business is energy, involving exploration for and production of crude oil and natural gas, manufacturing of petroleum products, and transportation and sale of crude oil, natural gas and petroleum products; exploration for and mining and sale of coal, and fabrication of nuclear fuel. Exxon Chemical Company is a major manufacturer and marketer of petrochemicals. Exxon is also engaged in exploration for and mining of minerals other than coal. Reliance Electric Company, an affiliate, manufactures, markets and services a broad line of industrial equipment. Exxon conducts extensive research programs in support of these businesses and provides capital to innovative new ventures, some of which are not related to these businesses.

The terms *corporation, company, Exxon, our,* and *its,* as used in this report, sometimes refer not only to Exxon Corporation or to one of its divisions but collectively to all of the companies affiliated with Exxon Corporation or to any one or more of them. The shorter terms are used merely for convenience and simplicity.

Contents

Reports Available to Shareholders

A financial and statistical supplement to this report, covering a ten-year period

Form 10-K, an annual report for 1984 as filed with the Securities and Exchange Commission

A description of Exxon's employee benefit plans, including pension plans, and a summary annual report of such plans

A summary of Exxon's progress in the employment of minorities and women in its U.S. work force and of its purchases from minority-owned businesses

A summary of Exxon's South African affiliates' employment policies and practices and community-related activities

Dimensions 84, a report on Exxon's 1984 contributions in the public interest

Dividend Reinvestment Plan

A brochure is available on Exxon's Dividend Reinvestment Plan. It explains how shareholders may increase their investment in the stock of the corporation without fees or service charges.

Requests for reports, other publications and information about company operations should be addressed to: *Exxon Corporation*
Shareholder Services
1251 Avenue of the Americas
New York, New York 10020-1198
or telephone collect
(212) 333-6900

Annual Meeting of Shareholders

The annual meeting of shareholders of the corporation will be held at the Scottish Rite Auditorium, 4357 Wilshire Boulevard, Los Angeles, California, on Thursday, May 16, 1985, at 9:30 a.m. Los Angeles time.

Transfer Agents

Stock certificates may be transferred at the following transfer agents' offices:

Bank of America National Trust and Savings Association
201 Mission Street
San Francisco, California 94105

First City National Bank of Houston
1301 Fannin
Houston, Texas 77002

The First National Bank of Boston
50 Morrissey Boulevard
Dorchester, Massachusetts 02125

The First National Bank of Chicago
One First National Plaza
Chicago, Illinois 60670

Morgan Guaranty Trust Company of New York
30 West Broadway
New York, New York 10007-2193

Inquiries regarding the Dividend Reinvestment Plan, dividend payments, stock transfer requirements, address changes and account consolidations should be addressed to: *Morgan Guaranty Trust*
Company of New York
Post Office Box 7600
Church Street Station
New York, New York 10249-7600
Telephone (212) 587-6472

Highlights

Financial	1983	1984
Net income billions of dollars	$ 5.0	**$ 5.5**
Net income per share	$ 5.78	**$ 6.77**
Dividends per share	$ 3.10	**$ 3.35**
Shareholders' equity per share	$34.80	**$36.84**
Return on average shareholders' equity percent	17.2	**19.0**
Return on average capital employed percent*	14.5	**15.4**
Revenue billions of dollars	$ 94.7	**$ 97.3**
Net income to revenue percent	5.3	**5.8**
Capital and exploration expenditures billions of dollars	$ 9.0	**$ 9.8**
Research and development costs millions of dollars	$ 692	**$ 736**

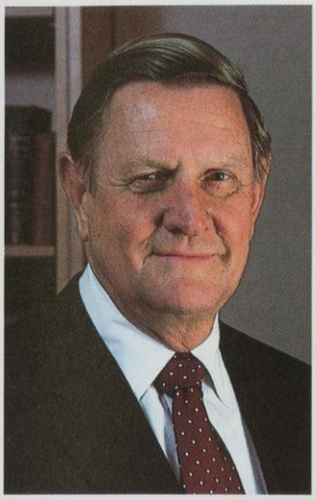
Operating		
Net production and supplies — liquids thousands of barrels daily		
Exxon production	1,582	**1,655**
Purchases under special agreements	1,000	**715**
Refinery crude oil runs thousands of barrels daily	3,266	**3,220**
Petroleum product sales thousands of barrels daily	4,085	**4,204**
Natural gas production available for sale millions of cubic feet daily	5,628	**5,918**
Chemical revenue millions of dollars	$7,689	**$8,372**

*See definitions on page 4.

COVER: *Seismic signals echoed from rock strata and processed by a new computer system developed by Exxon produced this contour map of a structure thousands of feet beneath the earth. The time required for echoes to return from various points on the upper surface of the formation varies with their distance below ground. Colors coded to correlate with time data and plotted on special paper indicate the topography of the underground strata. The red area is the high point of the formation; blue and light gray areas are low points. Such seismic displays can be invaluable in exploratory drilling operations (inset).*

Service station in Wayne, New Jersey (right), is one of 7,500 Exxon stations which now exemplify the new design the company began to install in its worldwide chain in 1981.

To the Shareholders



C. C. Garvin, Jr.

1984 was a year of record earnings for Exxon. Net income rose 11 percent and earnings per share 17 percent. Returns on shareholders' equity and on capital employed in the business were the best since 1980. Once again, the company benefited from efficiency measures and from higher crude oil production which more than offsets a decline in crude oil prices. Although by far the major part of our earnings increase came from upstream activities in oil and gas, other business segments contributed as well. Our chemical affiliate, in particular, had a good year, achieving a 60 percent earnings increase. Sizable profit improvements were also registered by Reliance Electric and our Hong Kong power project.

Financially, we ended the year in excellent shape. With only a modest increase in external debt, our cash flow enabled us to sustain a vigorous investment program, increase the dividend, and repurchase more than 64 million shares of Exxon stock. It is the latter fact that explains the greater percentage increase in earnings per share than in total net income.

It was not, however, a year without problems. Even though oil demand reversed a four-year decline, markets for oil, and for natural gas and chemicals as well, were intensely competitive. Upstream, worldwide industry excess producing capacity led to erosion of crude oil prices. Downstream, surplus capacity in refining and marketing, which has persisted for a number of years, became increasingly troublesome as 1984 wore on. For the oil industry as a whole, these developments added up to a difficult year.

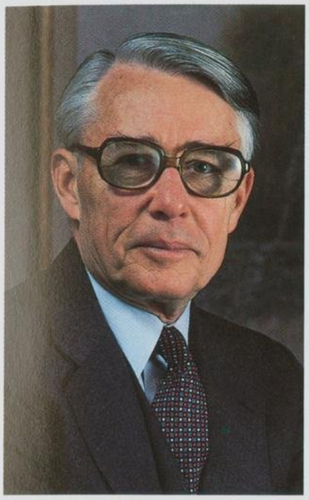
Exxon, too, felt the pressures, especially in the downstream where our earnings were well below those of the preceding year. By year end they were sufficiently weak to overcome favorable performance in other parts of the business, resulting in total corporate earnings for the fourth quarter less than those in the same quarters of either 1982 or 1983. Downstream weakness did not, however, offset the exceptionally good results achieved in the first three quarters. All in all, it was a particularly gratifying year for Exxon, given the widespread problems that confronted the industry.

How long downstream readjustment in the oil industry will continue remains to be seen, but clearly it has further to go. Most analysts are predicting future oil demand growth of only 1 percent or so per year. Without further reductions in capacity, this will not allow the industry to grow out of its problem within the foreseeable future. In our own case, we have reduced refining capacity by about 30 percent since 1979, the most recent action being the closing of our facility on the island of Aruba. In marketing, we have continued to upgrade our retail network by consolidating volume in fewer and larger sites. These steps have resulted in lower unit operating costs throughout our downstream operations. Along with the rest of industry, we have become more efficient, and we expect the process to continue.

Upstream, there are similar problems. The common expectation is that, absent a new supply crisis, excess crude oil producibility will continue to exert downward pressure on crude oil prices for some time to come. Longer run, however, the world still has to face the fact that it is consuming more oil than it is finding. Since that disparity is likely to become greater with the passage of time, we remain convinced that there is good reason to continue the search for new supplies. Success in finding them will be amply rewarded.

Our business plans reflect these considerations, both the immediate pressures and the longer-range supply and demand outlook. We know, first, that we must stress efficiency in everything we do. The difficult decisions that this sometimes requires are not taken lightly. We are mindful of the possible consequences, both for our employees and for the communities in which we have our operations. But the circumstances of the petroleum industry have left us little choice. The fact is that without the better use of personnel and facilities that we have achieved over the past five years, 1984 earnings would have been some half a billion dollars less than they actually were. While it becomes harder and harder at each step to achieve progress at the same rate as before, our goal is clear: to be the most efficient competitor in each of our businesses—in oil and gas, in chemicals, and in every other activity.

Secondly, we continue to reexamine all segments of our business to make sure that their prospects for the longer run are favorable. In some cases, attaining the efficiency or uniqueness sufficient to ensure viability in highly competitive markets is exceedingly difficult. Exxon Office Systems is an example. Because of further losses and the need to substantially broaden the product line if we were to continue participation in the rapidly changing office automation market, we recently decided to divest



H.C. Kauffmann

this part of our business. In January of this year, Olivetti agreed to acquire the non-U. S. assets of Exxon Office Systems. A month later a similar agreement was made with Lanier covering the U.S. operations. Better results were realized in a number of other ventures that lie outside our traditional oil, gas, and chemicals activities. Our coal business continues to progress, the potential for minerals remains substantial, and as mentioned, Reliance Electric showed encouragingly better earnings in 1984.

With respect to the longer run, our most vital decisions concern how best to use our financial strength in the interests of our shareholders. Historically, 80 percent or more of Exxon's investments have been in oil and natural gas, and the rest largely in other forms of energy and in petrochemicals. Our highest priority for the future is the search for new supplies of oil and natural gas. One need only look at the relative contribution of exploration and production to our total earnings to understand why this is so.

In recent years we have intensified our drilling effort with good results. For the third year running we succeeded in increasing our combined booked reserves of oil and natural gas. Moreover, our unit finding costs have been among the lowest in the industry. In the years ahead, we plan both to increase our effort in those areas where historically we have done well and to sustain our activity in frontier areas. How long and how vigorously we pursue such efforts will, of course, depend on the results we achieve.

The continuation of an aggressive exploration program does not rule out the acquisition of reserves from others. Purchases that yield acceptable economic returns, however, are not always available. In our case, the acquisitions that we have found most attractive are those that in one way or another complement our established operations. Pursuing this objective, Exxon USA in 1984 bought over 60 million oil equivalent barrels of good quality proved oil and gas reserves located in several states. These acquisitions, while not large compared to Exxon's total reserves, are a good fit with existing operations and can be expected to result in additional proved reserves as they are further developed. From time to time we have also looked at the possibility of acquiring entire companies rather than just individual properties, but we have not found opportunities that in our judgment were in the best interests of our shareholders.

Another use of a portion of our funds that has made good sense for our shareholders has been the repurchase of Exxon stock. Since July 1983, we have bought back roughly 10 percent of the outstanding shares. The effect has been to increase the amount of oil and gas represented by each share retained by shareholders, to increase earnings per share and to enhance shareholder return. We believe that these repurchases have been a good use of available funds and we are currently making more of them. This is an activity that requires close monitoring, however, since it depends on cash flow, alternative investment needs, and a variety of other factors. As is shown by the continuing high level of our capital and exploration expenditures, we do not regard share repurchases as a substitute for capital outlays that meet the return criteria we have established, but as a supplement to them.

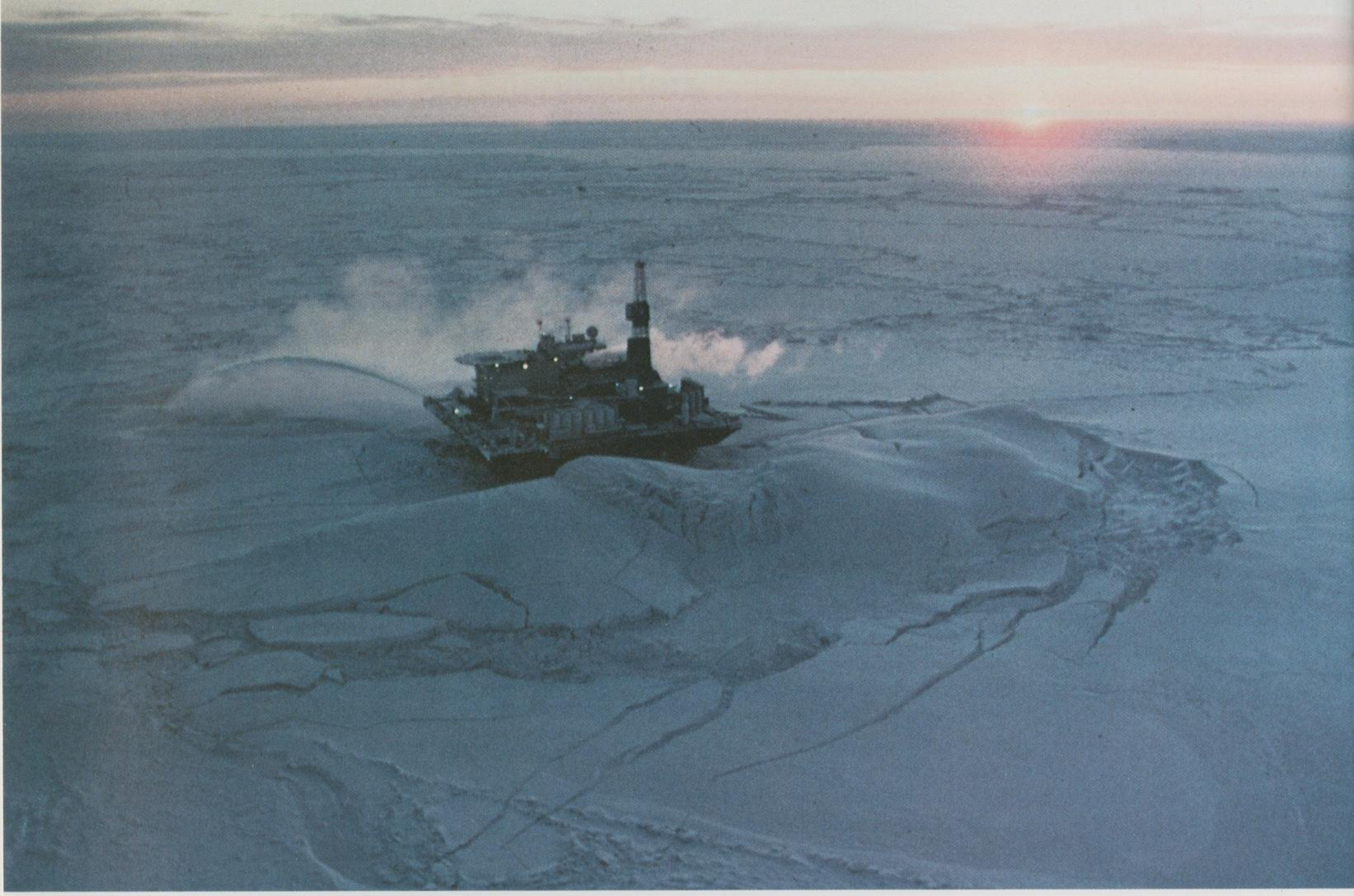
In all these decisions, our guiding principle is to put the shareholder's money to the best use that circumstances and a reasonable regard for the future allow. There will be times when the industry environment keeps us from fully achieving our objectives, but a philosophy of flexibility has served us well in the past and we believe it will do so in the years to come. So, despite the difficult industry outlook, we look to the future with optimism. We have excellent people, excellent technology, an organization that has adapted effectively to changing circumstances, and a strong financial position. And we are selling products that the world will continue to need.

Our employees, in particular, contributed greatly to our success in 1984. They have our special thanks. We are grateful, as well, for the continued support and interest of our shareholders. We look forward to seeing as many as possible of you at the annual meeting in May.

FOR THE BOARD OF DIRECTORS
March 4, 1985

C C Garvin Jr.
C.C. GARVIN, JR., *Chairman*

H.C. KAUFFMANN, *President*



REVIEW OF THE YEAR

Higher oil and gas production paced 11 percent earnings increase.

Functional and geographic analysis of results	Earnings After Income Taxes 1983	1984	Average Capital Employed* 1983	1984
	millions of dollars			
Energy operations				
Petroleum and natural gas				
United States				
Exploration and production	$1,866	$2,012	$11,625	$11,907
Refining and marketing	456	161	2,535	2,380
Foreign				
Exploration and production	2,213	2,777	4,724	4,428
Refining and marketing	674	196	6,151	5,730
International marine	(126)	(117)	1,031	828
Coal mining and development	37	43	792	1,057
Other energy	20	47	1,790	1,855
Total energy operations	5,140	5,119	28,648	28,185
Chemical operations				
United States	118	204	1,890	1,858
Foreign	152	226	1,889	1,875
Reliance Electric operations	(58)	11	1,307	1,230
Minerals mining and development	(57)	(52)	338	352
Other operations	95	53	281	514
Unallocated corporate costs	(322)	(317)	(670)	(694)
Interest (expense)/income — net	(90)	284	2,544	2,460
Net income	$4,978	$5,528	$36,227	$35,780

*Capital employed consists of shareholders' equity and debt, including Exxon's share of amounts applicable to equity companies. Return represents net income before deducting interest expense divided by average capital employed.

Earnings from increased production of crude oil and natural gas and the improved performance in chemicals and Reliance Electric more than offset reduced earnings in refining and marketing. Sales volumes and revenues were higher, buoyed by economic recovery.

Excess industry capacity kept pressure on refining and marketing margins throughout the year. The pressure was particularly severe during the second half, when the industry drew down stocks of crude oil and products accumulated earlier in the year and the economic recovery trend in the United States moderated.

A drilling rig built to work where few can venture, the concrete island drilling system (CIDS) made its debut in 1984 exploring Exxon's Antares prospect in the ice-clogged Beaufort Sea north of Alaska. The steel and concrete structure, with a deck as large as two football fields, was floated to position and sunk in 60 feet of water to provide a stable drilling platform which resists the crushing ice pressures. This view shows seawater being sprayed to build up an ice barrier for added protection. The reusable CIDS is a cost-effective alternative to building gravel islands for oil exploration in these waters.

Business Profile — Exploration and Production	1983	1984
	millions of dollars	
Earnings		
United States	1,866	2,012
Foreign	2,213	2,777
Total	4,079	4,789
Average capital employed		
United States	11,625	11,907
Foreign	4,724	4,428
Total	16,349	16,335
Capital and exploration expenditures		
United States	3,564	4,224
Foreign	2,521	2,715
Total	6,085	6,939
Research and development costs	151	174
	percent	
Return on average capital employed		
United States	16.1	16.9
Foreign	46.8	62.7
Total	24.9	29.3
	thousands of barrels daily	
Net production and supplies — liquids		
Net production		
United States	781	778
Foreign	746	835
Proportional interest in production of equity companies	32	21
Oil sands production — Canada	23	21
	1,582	1,655
Long-term agreements with governments	706	489
Other supplies available under special agreements	294	226
Total	2,582	2,370
	millions of cubic feet daily	
Natural gas production available for sale		
Net production		
United States	2,345	2,485
Foreign	1,327	1,522
Proportional interest in production of equity companies	1,956	1,911
Total	5,628	5,918

Petroleum and Natural Gas
Exploration and Production

Upstream earnings hit record high.

A 17 percent increase in upstream earnings, to $4.8 billion, was due mainly to increased production of crude oil and natural gas liquids from company properties. Total liquids production was up by 5 percent, with most of the gain in the U.K. North Sea, the Far East and the Gulf of Mexico. Gas sales, stimulated by economic recovery and by cold weather early in the year, also increased, reversing a long-term decline.

The company drilled a record 1,725 development wells to maintain or increase field productivity.

Reserves increased again.

The company increased its worldwide reserves on an oil equivalent basis for the third straight year, as additions to oil and gas reserves through discoveries, extensions to existing fields, purchases and revised recovery estimates more than replaced production. U.S. reserves also increased on an oil equivalent basis.

Improved recovery projects in the United States and Canada added 104 million barrels to total crude oil reserves. The company also purchased and booked over 60 million barrels (oil equivalent) of proved U.S. oil and gas reserves. These property purchases are expected to yield further reserves in future years. Discoveries at Mobile Bay, Alabama, and delineation drilling of a past discovery at LaBarge, Wyoming, also contributed to the U.S. reserves increase.

Major gas reserves confirmed in Mobile Bay.

Exploratory drilling in the Mobile Bay area offshore Alabama established the presence of major gas reserves with the potential of being one of the most significant U.S. finds in recent years. Based on results from the first few wells, Exxon booked over 500 billion cubic feet of proved reserves.

The company acquired an additional 62,000 net acres in the area at a cost of $316 million, bringing its total holdings to 135,000 net acres. Exxon completed two wells on its Mobile Bay acreage in 1984 and is operating or participating in four additional wells.

The jack-up rig Prober *(above) is shown drilling one of the wells which confirmed a major deposit of natural gas on Exxon acreage in Mobile Bay, Alabama. Exxon is drilling several additional wells in the area in 1985.*

Manual tracing with colored pencils is no longer adequate to display and interpret the massive amounts of seismic information generated by new data-collecting techniques. A computer-driven system developed by Exxon Production Research for manipulating and displaying such data (demonstrated below by researchers Cliff Petersen and Dianna Green) was installed in Exxon exploration offices worldwide in 1984. The system created the display shown on the cover of this report.

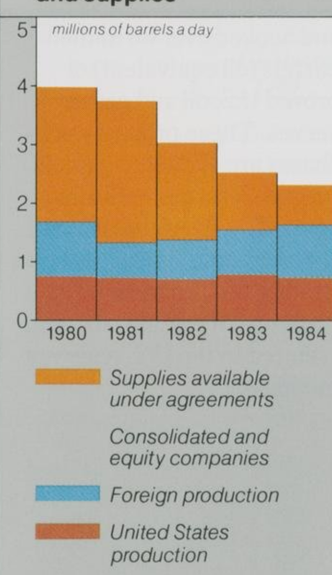
Aerial view of Cold Lake heavy oil project in eastern Alberta (right) shows two "pads" of up to 20 wells each and pipelines which link them to steam generators and oil treatment facilities. A dozen pads are included in the first two phases of Imperial's program to develop its heavy oil reserves by injecting steam into buried oil sands and pumping the heated oil to the surface.

Exploration acreage increased in U.S. offshore and abroad.

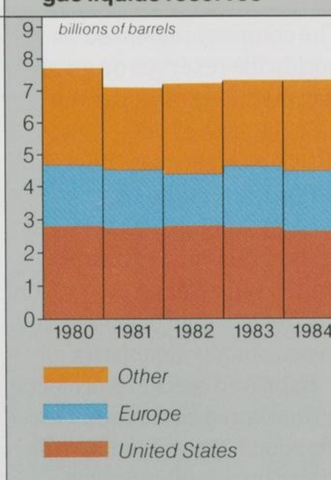
A total of $218 million was spent in three Federal lease sales in the Gulf of Mexico, where Exxon has almost tripled its holdings in the past two years. Offshore Alaska, the company spent $260 million for additional acreage in the Beaufort Sea and in the Navarin basin of the Bering Sea.

Exploration acreage was also acquired in Australia, Colombia, Egypt, Morocco, New Zealand, Norway, Somalia and the United Arab Emirates.

Net liquids production and supplies



Crude oil and natural gas liquids reserves



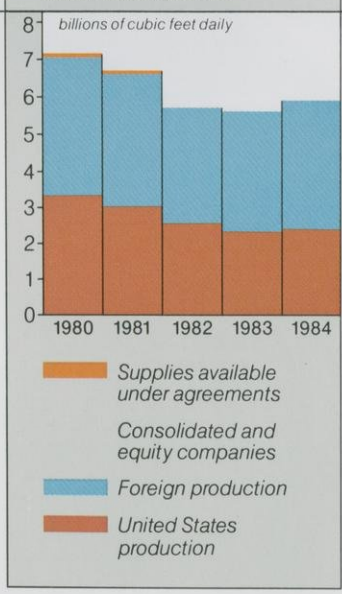
Discoveries made in nine countries.

The company made or participated in over 70 oil and gas discoveries in nine countries. A record number of exploration wells were drilled in the United States, and several significant discoveries were made. Besides Mobile Bay, these included a gas and oil find on Mississippi Canyon block 397 in 1,400 feet of water in the Gulf of Mexico and an onshore gas find near Rowlands, Mississippi. Foreign discoveries included a major oil find in block 34-7 offshore Norway, in which Exxon has an initial 15 percent interest, an oil discovery in Rotterdam, the Netherlands, in which Exxon has a 50 percent interest, and two gas discoveries in

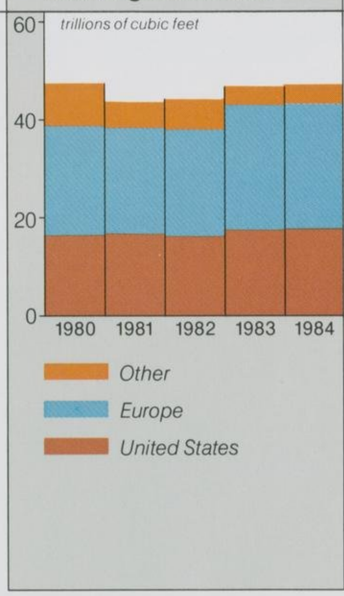
Canada's Mackenzie Delta/ Beaufort Sea region.

Offshore Alaska, initial drilling in the Bering Sea's St. George and Norton basins was unsuccessful. In the western Beaufort Sea, the first well drilled at the Antares prospect was abandoned after testing non-commercial quantities of oil. Another well is being directionally drilled from the same location to evaluate the structure further.

Natural gas production available for sale



Natural gas reserves



Construction started on Wyoming gas project.

Exxon USA began development of the large gas deposit at LaBarge in southwestern Wyoming. The first phase of the project will produce more than 400 million cubic feet a day of raw gas which includes about 22 percent natural gas and 66 percent carbon dioxide. Gas production is scheduled to begin in 1986.

Sales contracts have been signed for daily delivery of about 85 million cubic feet of natural gas and up to 200 million cubic feet of carbon dioxide, which is widely used in improving recovery from petroleum reservoirs.

Development projects launched on Alaskan North Slope.

Owners of the Prudhoe Bay unit approved a drilling program to develop the western end of the giant field and a project to improve oil recovery in part of the field by miscible gas flooding. Drilling is under way to develop reserves in the Lisburne reservoir which underlies the main Prudhoe Bay reservoir. Exxon's 40 percent share in the Lisburne amounts to 115 million barrels.

Development is also proceeding at the Endicott field 15 miles northeast of Prudhoe Bay. Exxon's 21 percent participation at Endicott amounts to 70 million barrels of reserves.

Bicyclists on a suburban road near Rotterdam (right) pass a rig drilling an exploratory well for Exxon. The company made a 1984 oil discovery in the Rotterdam area, a great oil port and refining center but not—until now—a place known for its petroleum resources.

Distant thunderheads make a dramatic backdrop in this sunset view of the floating rig Jim Cunningham *drilling an exploratory well for Exxon in the Pearl River Mouth basin offshore the People's Republic of China. Drilling operations in PRC waters began in early 1984 and are continuing in 1985.*

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New contract prices to boost U.S. gas revenues.

Exxon negotiated sales of natural gas in Texas markets to replace long-term sales contracts which expired at year-end 1984. The volumes to be sold under the new agreements represent about 15 percent of Exxon's current U.S. production.

The expiring contracts, signed in the 1960s when gas prices were at low levels, committed Exxon to selling prices which were far below 1984 market values. Prices in the new contracts reflect current market values.

North Sea crude oil production reached new high.

Exxon's net share of liquids production from United Kingdom fields increased by 10 percent to 344,000 barrels a day, with most of the buildup occurring in the Brent, Cormorant and Fulmar fields.

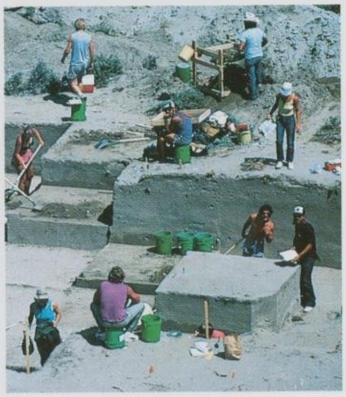
Also in U.K. waters, a project was approved to develop the estimated 100 million barrels (Exxon share) of oil in the Tern field. In Norway, a third platform was placed on the big Statfjord field (Exxon share: 8.4 percent), and the Odin field (Exxon share: 100 percent) produced its first gas.

New gas liquids plant on stream in Scotland.

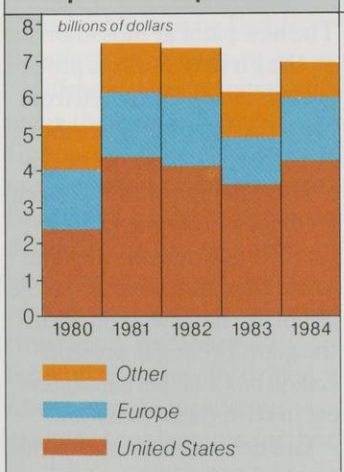
The new plant at Mossmorran on the Firth of Forth is processing liquids extracted from North Sea gas brought ashore at St. Fergus. Most of the liquids are being sold as chemical feedstocks pending completion of a petrochemical plant at Mossmorran which, like the gas plant, is associated with the giant Brent gas project. Exxon has a 50 percent interest in all of these facilities.

Gas deliveries at St. Fergus reached 700 million cubic feet a day, as production from U.K. fields was supplemented by gas from the Odin field in Norwegian waters.

Rig (left) near LaBarge, Wyoming, drills one of the wells planned to develop Exxon's substantial reserves of natural gas and carbon dioxide here in the foothills of the Rockies. Shute Creek location of the gas processing plant included in the project is an important archaeological site, with Stone Age relics dating back 5,000 years. Some 50 excavators (below) are examining the site to recover all objects of interest before construction starts.



Producing capital and exploration expenditures



New platforms boost Malaysian oil production. Gas sales began.

Production started from three new platforms off the east coast of peninsular Malaysia. Crude oil production increased by 27 percent to 225,000 barrels a day (Exxon net share: 96,000 barrels).

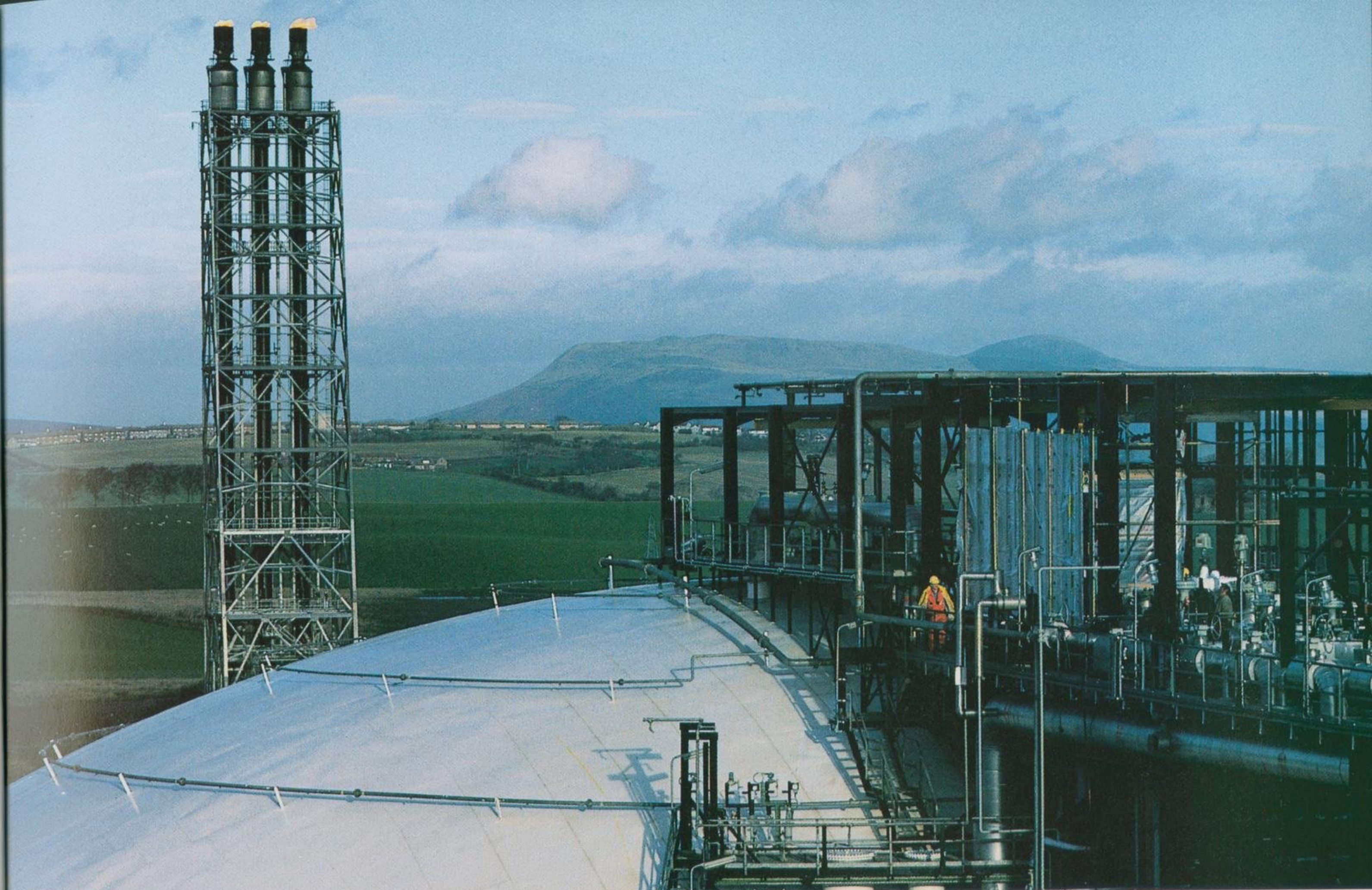
The sale of natural gas from these offshore properties began with the first deliveries to the government oil company.

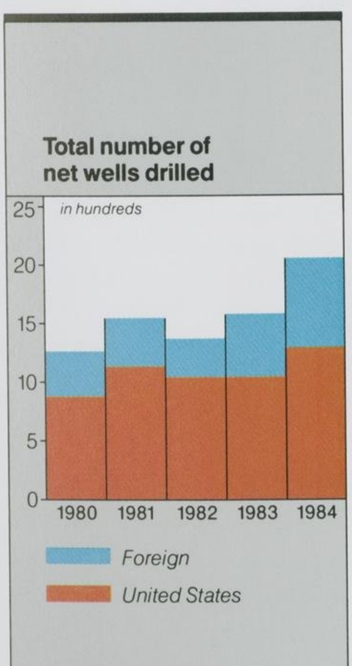
Australian production also at new high.

Exxon's share of liquids production in the Bass Strait rose 14 percent to a record 214,000 barrels a day. A platform installed on the Flounder field began producing late in 1984. Plans are under way for a platform to be installed on the Bream field in 1987.

Japanese gas project on stream.

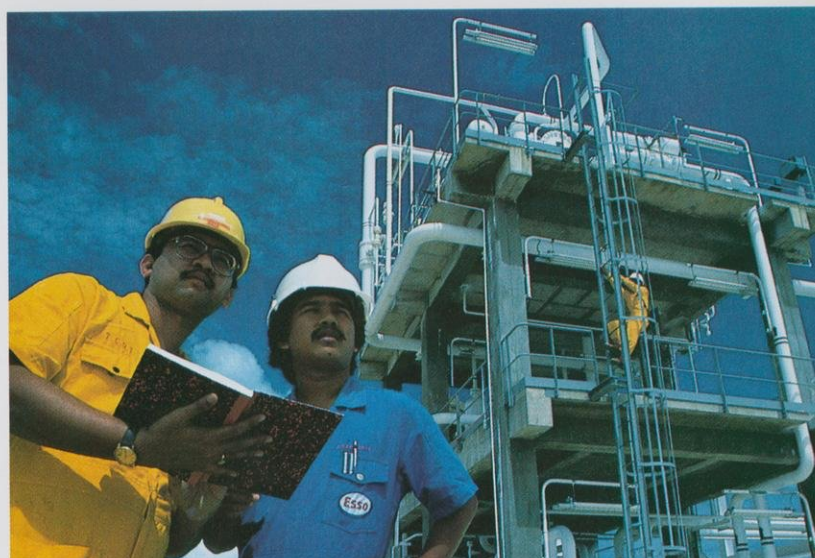
Production at the Iwaki field off the east coast of Honshu began at midyear and averaged 32 million cubic feet a day after startup. Exxon has a 40 percent share in the project, which produces gas for sale to the Tokyo Electric Power Company.

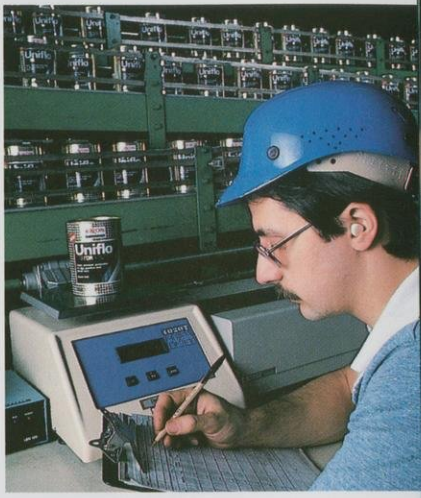




Exxon has a half interest in a new fractionation plant at Mossmorran, Scotland (above), which processes natural gas liquids from the North Sea to make LPG and petrochemical feedstocks. Liquids separated from gas brought ashore at St. Fergus are moved south to Mossmorran through a 138-mile pipeline.

Esso Production Malaysia employees Mohd. Zahir Zakaria and Anuar Buang check onshore facilities which Exxon opened in Malaysia to process natural gas from offshore platforms for sale to the government oil company.





Specialties group leader Anthony Lanni checks weight and label of a random sample as cans of new EXXON UNIFLO 10W-30 motor oil move off the canning line at Exxon's specialties packaging plant in Bayonne, New Jersey.

Business Profile — Refining and Marketing	1983	1984
	millions of dollars	
Earnings		
United States	456	161
Foreign	674	196
Total	1,130	357
Average capital employed		
United States	2,535	2,380
Foreign	6,151	5,730
Total	8,686	8,110
Capital expenditures		
United States	363	380
Foreign	818	1,003
Total	1,181	1,383
Research and development costs	113	111
	percent	
Return on average capital employed		
United States	18.0	6.8
Foreign	11.0	3.4
Total	13.0	4.4
	thousands of barrels daily	
Petroleum product sales		
United States	1,146	1,149
Foreign	2,939	3,055
Total	4,085	4,204
Refinery crude oil runs		
United States	958	1,021
Foreign	2,308	2,199
Total	3,266	3,220

Refining and Marketing

Depressed margins affect downstream earnings.

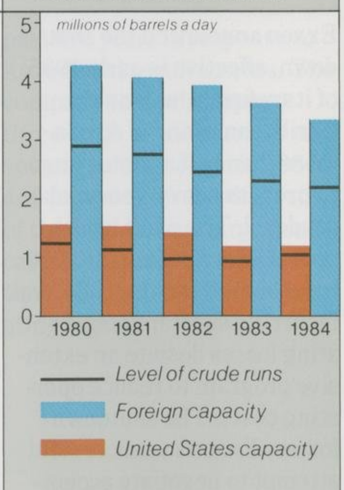
A delayed coker (center background) at Exxon's refinery in Karlsruhe, West Germany, went into operation in 1984. The unit converts some 15,000 barrels of heavy fuel oil a day into lighter petroleum products and a by-product of high-quality coke. The coke, which accumulates in huge reactor drums as a solid mass, is sold as an industrial fuel.

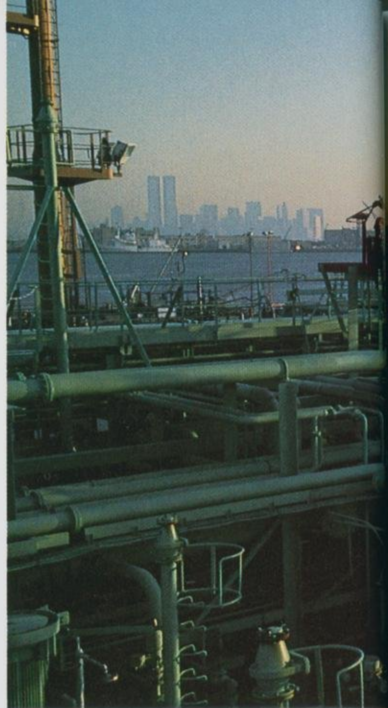
Despite higher product sales volumes and continued progress in reducing operating costs, earnings in this segment were 68 percent below 1983 levels. Intense competition due to ample crude oil supplies and surplus refining capacity severely depressed profit margins. In this weak market environment, the continued strengthening of the U.S. dollar hurt the results of foreign affiliates, especially in Europe, which pay for crude oil in dollars but sell in local currencies.

Fears that attacks on shipping arising from the Iran-Iraq war might cut off supplies of Middle East oil caused a rapid buildup of industry crude oil and product inventories in the spring of 1984. The drawdown of surplus inventories after oil supply worries eased, combined with the availability of more than adequate supplies, led to lower product prices later in the year.

In addition, the price differential between lighter products and heavy fuel oil narrowed in 1984, due in part to an increase in fuel oil demand spurred by the U.K. coal miners' strike. This reduced the profitability of high-intensity refiners like Exxon who upgrade a relatively large proportion of fuel oil to light products, which are normally more valuable.

Refining capacity and level of crude runs





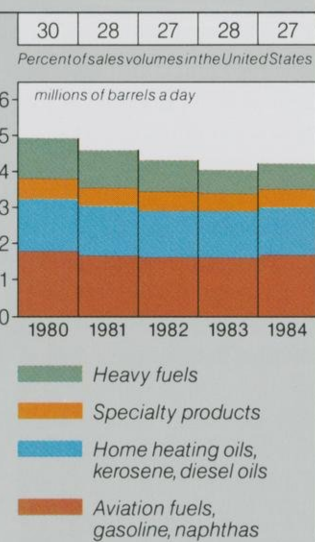
Workers at left are preparing the foundation for the FLEXICOKING unit which is part of a $560 million upgrading project at the Rotterdam refinery. The unit, which uses an Exxon-developed process to convert heavy fuel to light products and fuel gas, is scheduled to start up in 1986 at a rate of 32,000 barrels a day. A similar installation under construction at Baytown, Texas, will go on stream in 1987.

Aruba refinery shutdown announced.

Exxon announced the shutdown, effective in early 1985, of its refinery built on the Caribbean island of Aruba more than half a century ago to process heavy Venezuelan crude oil. The plant, which operated at a rate of 200,000 barrels a day during 1984, was incurring substantial operating losses despite an extensive program to reduce operating costs. The shutdown follows Exxon's unsuccessful attempt to negotiate acceptable supply terms with the Venezuelan government oil company, which was the refinery's principal source of crude oil.

In a long-term program to reduce refining costs, Exxon has idled less efficient equipment and sold or shut down a total of 14 refineries since 1979, substantially reducing basic crude distillation capacity. Meanwhile, it has continued to increase capacity to convert heavy fuel oil into lighter products. Conversion projects include a delayed coker which went on stream in 1984 at Karlsruhe, West Germany, and a fluid catalytic cracking unit which went into service at Sakai, Japan, in early 1985.

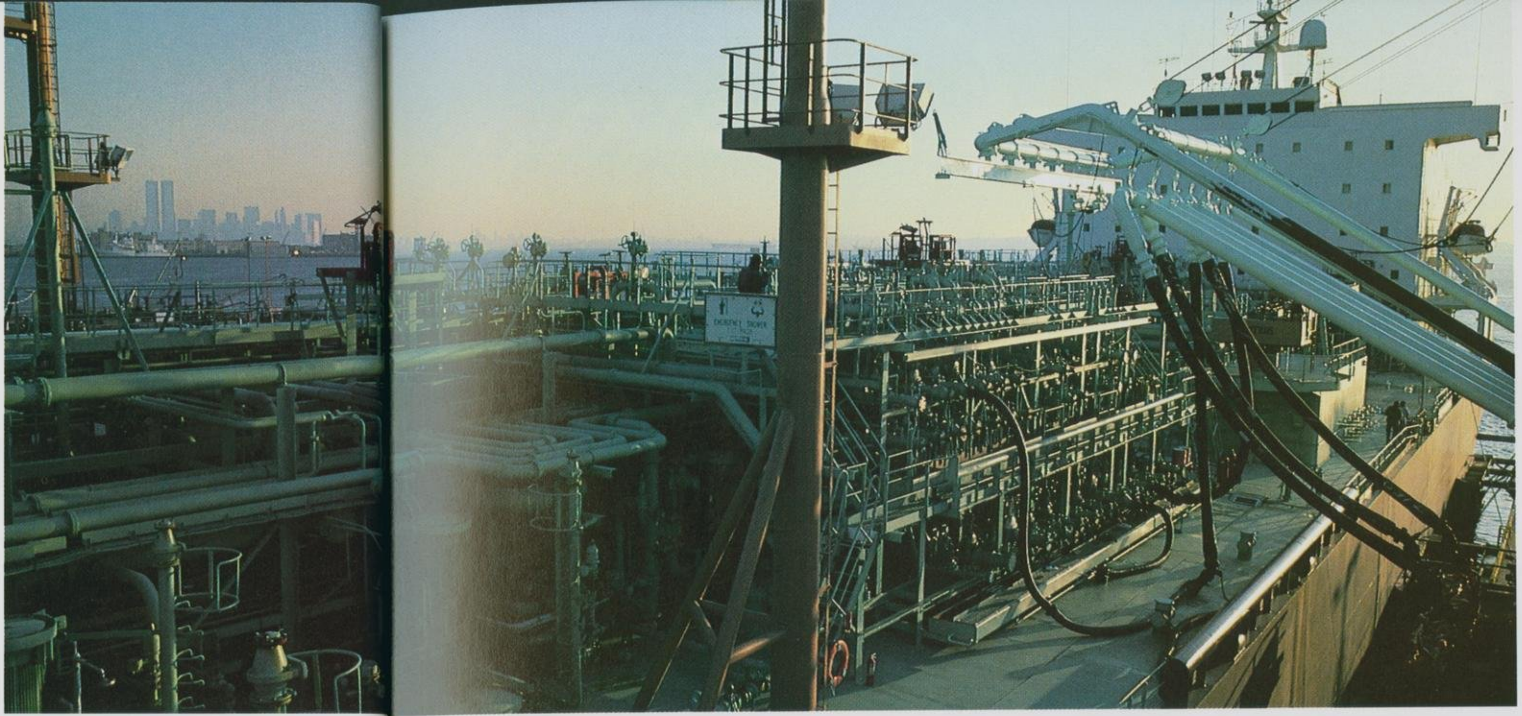
Petroleum product sales volumes



Specialties sales scored big gains.

Exxon sales volumes of lubricants and lube-related specialty products increased by 7 percent, primarily reflecting the improved economy. While these high-value products accounted for only about 2 percent of total product volumes, they contributed a substantial proportion of refining and marketing earnings.

The company maintained its position as the largest supplier of blend stocks to lubricant manufacturers, at the same time increasing its sales of finished oils.



The Exxon Wilmington *is one of two 42,000 dwt specialty tankers commissioned by the company in 1984 to replace older, less efficient vessels in U.S. specialty service. Capable of carrying 43 different products in separate cargo tanks, the ship is shown unloading petroleum products at the Bayonne, New Jersey, terminal, which was modernized to accommodate the new vessels.*

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New high-performance motor oil meets requirements of all vehicles.

Super-premium EXXON UNIFLO 10W-30, introduced in the United States, meets the requirements of all gasoline, diesel and turbo-charged engines on both domestic and imported cars and light trucks. Compared to a leading competitive motor oil in tests using a group of New York taxicabs, Exxon's new oil cut engine wear nearly in half and sharply reduced engine deposits.

Service station chain upgraded.

The number of stations in the company's worldwide chain was reduced by 2,000, as Exxon continued to phase out relatively low-volume, less efficient outlets. Since 1979, Exxon has reduced its chain by about 25 percent, while the throughput of its average station has increased by nearly 30 percent.

Exxon continued to install the new design for station architecture and signs which it introduced in 1981. More than 7,500 stations now reflect the attractive new design.

Business Profile — International Marine	1983	1984
	millions of dollars	
Earnings/(loss)	(126)	(117)
Average capital employed	1,031	828
Capital expenditures	14	5
Research and development costs	3	2
	millions of deadweight tons	
Average capacity, worldwide		
Owned vessels	13.3	12.0
Chartered vessels	2.5	1.5
Total	15.8	13.5

International Marine

Lower transport needs led to fleet reductions.

Losses in this segment were due to reduced shipping requirements, continued depressed freight rates and vessel write-offs. Ship utilization was down because Exxon obtained a smaller share of its crude oil supplies from Middle East sources which require long-haul ocean transport.

Exxon has reduced the size of its owned and term-chartered international and coastal fleets by 40 percent over the past five years in response to its reduced requirements. The company sold or scrapped three large crude carriers and several smaller ships in 1984, and provided for the disposal of three additional large crude carriers. These fleet reductions will result in lower operating costs.


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At the Cerrejón project in Colombia, a power shovel loads coal (opposite) on a 170-ton truck for removal to a nearby stockpile. As coal mining progresses, trucks will fill excavated area with overburden and topsoil for reclamation. Three-year training cycle for project workers includes classroom instruction at a training center in Barranquilla (above) run by Exxon's Intercor affiliate, where trainees Oscar Martinez and Jose Churio review an equipment list.

Business Profile — Coal Mining and Development	1983	1984
	millions of dollars	
Earnings		
Operating mines and sales of reserves	60	65
New business and mine development costs	(23)	(22)
	37	43
Average capital employed	792	1,057
Capital and exploration expenditures	336	318
Research and development costs	7	8
Revenue	272	327
	millions of short tons	
Recoverable reserves	10,566	11,070
Production	20.5	25.1
Design capacity		
Existing operations	37.9	37.9
Under construction	8.3	8.3
Mines		
In operation	5	5
Under development	1	1

Coal Mining and Development

Earnings set record on higher output.

Earnings from coal operations reached record levels, as production from Exxon's four active U.S. mines increased 20 percent to 23.2 million short tons, reflecting higher demand. Continued gains in productivity also contributed to the improved results.

The company's total coal output was boosted by initial production from the Cerrejón project in Colombia and by higher production from Imperial's Byron Creek surface mine in British Columbia.

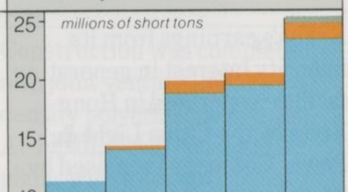
Imperial announced plans to build a new coal-washing plant which will increase saleable reserves at Byron Creek from 16 million to 77 million short tons. The plant is scheduled for start up in 1986.

Mining under way at Colombia project.

More than 800,000 short tons of coal were mined for stockpiling at the big Cerrejón project which Exxon operates in a 50/50 partnership with the Colombian government coal company. The first shipment to a customer from the new coal port, Puerto Bolívar, was made in early 1985. Sales contracts for Cerrejón coal have been signed with a number of customers, primarily in Europe, and all available coal is committed for 1985.

A 90-mile railroad was completed connecting the mine in the interior of the Guajira peninsula with Puerto Bolívar. Mine and port facilities were still under construction at year end.

Coal production



Research technicians Don Messerschmidt and Jean Palmer take samples of combusted shale at the pilot plant started up in Baytown, Texas, in 1984 to test Exxon technology for the recovery of shale oil. The plant can process five tons of shale per day, producing a hydrocarbon which can be upgraded to a synthetic crude oil.

Business Profile — Other Energy	1983	1984
	millions of dollars	
Earnings		
Hong Kong power generation	71	88
Uranium mining and nuclear fuel fabrication	23	20
Other	(74)	(61)
	20	47
Average capital employed	1,790	1,855
Capital and exploration expenditures	430	344
Research and development costs	80	74
	thousands of metric tons	
Uranium		
Recoverable reserves — contained U_3O_8	13	13
Ore milled	805	376
Production of U_3O_8 — millions of pounds	1.5	.4
Uranium mines		
In operation	1	—

Other Energy

Expansion increased earnings from Hong Kong power plant.

Exxon's earnings from its majority interest in generating facilities operated in Hong Kong by the China Light & Power Company increased by 24 percent, reflecting the phased expansion program now under way. The last of four 350-megawatt, coal-fired generators at the Castle Peak "A" station started up ahead of schedule. Construction continued on three of four 660-megawatt units planned for the "B" station.

The projected dollar cost of the expansion project has been reduced from $3.5 billion to $3 billion to reflect cost efficiencies and the rising value of the U.S. dollar relative to the other currencies involved.

Exxon Nuclear earnings rose despite lower volumes.

The company maintained a strong earnings performance despite reduced product shipments due to reactor deferrals.

Orders increased in the European market, due in part to the full commercialization of an advanced fuel design for boiling water reactors. In the United States, Exxon Nuclear signed a contract with a utility customer for the demonstration of an advanced fuel design for pressurized water reactors.

Uranium mining ends.

The Highland surface mine and mill in Wyoming were closed down by midyear, and post-mining land reclamation was started at the site. The shutdown ended Exxon's participation in uranium mining, where prospective returns have been dimmed by lower-than-expected demand and depressed prices. Imperial still holds undeveloped uranium reserves in Canada.

Pilot plant tests new shale oil technology.

A $14 million pilot plant to test the recovery of oil from shale began operation at Baytown, Texas. The pilot program follows several years of research aimed at developing a more efficient, lower-cost method of retorting shale. It uses fluidized bed technology, building on Exxon's long experience with the use of fluidized beds in petroleum refining. With a capacity of five tons of shale per day, the plant is testing Exxon's retorting process on different shales under a wide range of conditions.

A new line of solvents introduced in 1984 by Exxon Chemical reduce vapor emissions and have slow-drying properties which result in a high-gloss finish. Paints and finishes made with EXXATE solvents, like the coating being applied in this automobile plant, are particularly well suited for robot spraying.

Business Profile — Chemicals	1983	1984
	millions of dollars	
Earnings		
United States	118	204
Foreign	152	226
Total	270	430
Average capital employed		
United States	1,890	1,858
Foreign	1,889	1,875
Total	3,779	3,733
Capital expenditures		
United States	207	109
Foreign	338	194
Total	545	303
Research and development costs	105	124
	percent	
Return on average capital employed		
United States	6.3	11.0
Foreign	8.1	12.1
Total	7.2	11.5

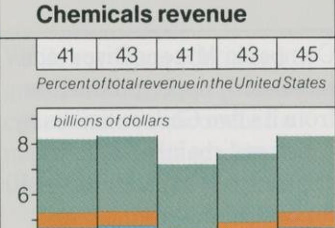
Chemicals

Strong first half boosted revenues and earnings.

Earnings were up 60 percent, as the recovery trend in chemical markets which started in 1983 extended through the first half of 1984. Exxon Chemical continued to achieve earnings growth and good returns in its business lines with large components of specialty products. While returns in the commodity-oriented business lines remained inadequate, earnings improved significantly over 1983.

Chemical industry production slowed after midyear, when inventory rebuilding peaked and economic growth moderated in the United States. Exxon Chemical's margins were under increasing pressure in the second half.

Chemicals revenue



New plants improved manufacturing efficiency.

Exxon Chemical completed the modernization and expansion of its paraxylene plant at Baytown, Texas, another step in a program to reduce costs by improvements in its manufacturing facilities. Also at Baytown, the startup of new polypropylene facilities based on proprietary catalyst systems helped results in this business line.

Saudi Arabian plant started up.

Construction was completed on a joint venture linear low-density polyethylene plant in Al-Jubail, Saudi Arabia. The plant, with a design capacity of 270,000 metric tons per year, started up three months ahead of schedule and well under budget. Its product will be marketed in the Middle East, Europe and the Far East.

The Distributed Digital Control System introduced by Reliance employs computer technology to control manufacturing systems in continuous process industries such as paper, textiles, steel strip and plastic film. Reliance technical service engineers Randy Bowers (left) and Tom Stewart (right) and sales engineer Dalton Wright monitor startup of a system in the plant of a major producer of woven fiber.

Business Profile — Reliance Electric	1983	1984
	millions of dollars	
Earnings/(loss)		
Operating results	(51)	15
Business development costs	(7)	(4)
	(58)	11
Average capital employed	1,307	1,230
Capital expenditures	55	51
Research and development costs	30	25
Revenue	1,397	1,538

Business Profile — Minerals Mining and Development	1983	1984
	millions of dollars	
Earnings/(loss)		
Operating results	(24)	(16)
Mine pre-development and development costs	(10)	(17)
Exploration costs	(23)	(19)
	(57)	(52)
Average capital employed	338	352
Capital and exploration expenditures	59	71
Research and development costs	5	4
Revenue	115	97
	thousands of metric tons	
Recoverable reserves — contained metal		
Copper	12,530	12,819
Zinc	4,212	4,212
Lead	353	353
Molybdenum	212	214
Gold—thousands of troy ounces	389	354
Production		
Copper	74	67
Copper mines		
In operation	3	2

Reliance Electric Company

Reliance returned to profitability as revenues rebounded.

Sales revenues increased by 10 percent, buoyed by the recovery trend in metals, machine tools and other key markets. New orders were up from 1983, and the year-end backlog substantially increased. Strong sales growth continued in the company's telecommunications business, which posted record profits.

Reliance continued its restructuring program to cut operating costs and improve productivity. Company investments focused on cost reduction projects, advanced manufacturing processes and product development.

New DC motors, telephone products introduced.

Reliance introduced a new generation of DC motors which combine a significant size reduction with advantages in performance and serviceability to reduce the total cost of operation.

Other new products included advanced connection, testing, diagnostic and power conversion equipment for the unregulated telecommunications industry, as well as a complete telephone system for small businesses and a credit card pay telephone which will accept bank credit cards and telephone calling cards.

Minerals Mining and Development

Productivity gains offset by lower copper prices.

Compañia Minera Disputada increased copper production from its two Chilean mines by 4 percent, mainly due to the expansion of capacity at the El Soldado underground mine. Productivity improvements reduced unit costs at both mines and at the smelter. But the favorable impact was offset by lost production due to severe winter conditions at the Los Bronces surface mine and by continued price weakness in world copper markets.

Canadian copper mine closed.

Production at the Granduc mine near Stewart, British Columbia, was stopped in April due to depressed copper prices and lack of success in delineating additional ore reserves. The assets were written down in earlier years, when prospects for the copper market weakened.

Quality control specialists check new automated fueling equipment at Gilbarco plant in Greensboro, North Carolina, operating each component individually and in combination with other units before release. From left, Fannie Zachary inspects a credit authorization terminal, Barbara Sanders checks cash register/pump controller displays, and Ronnie Whitsett verifies data exchanged between the system controller, self-service island card reader and cash register.

Business Profile — Other Operations	1983	1984
	millions of dollars	
Earnings		
Operating results	102	65
Business development costs	(7)	(12)
	95	53
Average capital employed	281	514
Capital expenditures	68	115
Research and development costs	83	87

Other Operations

Zilog posted sales gains, completed plant expansion.

While revenues continued to grow for Zilog, Inc., prices declined in its semiconductor markets as demand slowed in the second half of the year.

Completion of an expansion project at the plant in Nampa, Idaho, permits Zilog to apply advanced manufacturing technology both to existing products and to the 32-bit microprocessor which the company has announced. Zilog introduced an advanced version of its System 8000 multiuser super microcomputer which doubles the speed and accommodates more users.

Gilbarco introduced new service station control system.

The world's leading supplier of service station dispensing equipment, Gilbarco augmented its line of automation products with a powerful computer system which provides complete management control of all service station activities. The affiliate plans to market a new electronic cash register/card authorization terminal developed by Imperial Oil Limited.

Exxon sold office systems business.

Exxon decided late in the year to seek a buyer for Exxon Office Systems Company's business operations. The decision was prompted by further losses and the need to substantially broaden the product line in order to continue to participate in the highly competitive and rapidly changing office automation market.

Early in 1985, agreement was reached with Ing. C. Olivetti & C., S.p.A. to acquire the non-U.S. assets of Exxon Office Systems. A similar agreement was made with Lanier Business Products, Inc. covering the U.S. operations.

"American Foreign Policy—Where Do We Go From Here?" was the question at the second annual conference of former U.S. Secretaries of State sponsored by the Exxon Education Foundation in 1984. A one-hour public television program based on the proceedings at Atlanta's Woodruff Arts Center, underwritten by Exxon Corporation and others, was broadcast on January 8, 1985. Participants were (clockwise from top left) Dean Rusk, William P. Rogers, Cyrus Vance and Edmund Muskie.

Public Service Programs

Public service contributions totaled $58 million in U.S.

Exxon contributed $58 million to support public service activities in the United States, including $31 million in grant payments by the Exxon Education Foundation. This was a 10 percent increase over 1983. Contributions were to education (56 percent); health, welfare and community services (19 percent); public information and policy research (9 percent); and arts and public television programming (16 percent).

In addition, Exxon affiliates abroad contributed $11 million in their countries.

Foundation grants help universities attract and keep young scientists.

The Exxon Education Foundation announced a five-year program to distribute up to $1 million in matching grants among scientists and engineers selected by the National Science Foundation to receive Presidential Young Investigator Awards. The awards are given in recognition of research and teaching potential and are intended to help universities retain outstanding young Ph.D.'s who might otherwise pursue non-teaching careers.

Exxon grants aid inner city housing, youth employment.

A $500,000 grant went to the Enterprise Foundation, which makes grants and loans to community groups to develop housing for low-income families.

An Exxon grant of $625,000 to the New York Community Trust increased the company's support for their programs which prepare urban youth for entry into the labor force.

In its continuing program to improve energy conservation by U. S. institutions, the company made major grants to the Hospital Research & Educational Trust and to the United Way of America.

Equal Employment Opportunity

Minorities and women continued to make employment gains.

The percentage of minorities among Exxon's U. S. employees increased from 18.5 to 19.5 percent, and the percentage of women from 26.7 to 27.1 percent. These gains came in spite of a reduction in the company's U. S. work force.

At year end, women held 8.2 percent of managerial jobs, up from 8.0 percent in 1983. Minorities' share of these jobs fell slightly, from 7.9 to 7.8 percent. Minority representation in professional jobs was up from 10.6 to 10.8 percent, and the share held by women rose from 16.5 to 17.4 percent.

U. S.-based divisions hired 4,956 people in 1984. Of these, 44.5 percent were women and 22.6 percent minorities.

FINANCIAL SECTION

PAGE

Financial Review

Financial Summary

	1980	1981	1982	1983	1984
	(millions of dollars)				
Sales and other operating revenue					
Petroleum and natural gas	$ 98,238	102,418	92,570	83,622	85,415
Coal mining and development	159	204	288	272	327
Chemicals	6,928	7,116	6,049	6,392	6,870
Reliance Electric	1,595	1,673	1,561	1,397	1,538
Minerals mining and development	71	83	80	115	97
Other and eliminations	1,421	1,726	1,511	1,649	1,626
Total sales and other operating revenue	$ 108,412	113,220	102,059	93,447	**95,873**
Earnings					
Petroleum and natural gas					
Exploration and production	$ 3,797	4,117	3,431	4,079	4,789
Refining and marketing	1,784	1,108	1,125	1,130	357
International marine	41	29	(100)	(126)	(117)
Total	5,622	5,254	4,456	5,083	5,029
Coal mining and development	4	13	23	37	43
Other energy	(30)	(29)	(102)	20	47
Chemicals	345	238	93	270	430
Reliance Electric	(9)	29	(50)	(58)	11
Minerals mining and development	(40)	(97)	(114)	(57)	(52)
Other operations	(2)	(43)	37	95	53
Unallocated corporate costs	(468)	(316)	(291)	(322)	(317)
Interest (expense)/income-net	(72)	(223)	134	(90)	284
Net income	$ 5,350	4,826	4,186	4,978	**5,528**
Net income per share*	$ 6.15	5.58	4.82	5.78	6.77
Cash dividends per share*	$ 2.70	3.00	3.00	3.10	3.35
Net income to average shareholders' equity *(percent)*	21.0	17.8	14.9	17.2	19.0
Net income to total revenue *(percent)*	4.9	4.2	4.0	5.3	5.8
Working capital	$ 6,644	5,500	3,328	3,556	1,974
Ratio of current assets to current liabilities	1.39	1.31	1.20	1.24	1.13
Property, plant and equipment, less reserves	$ 31,181	35,286	38,982	40,868	42,776
Total additions to property, plant and equipment	$ 6,465	9,003	9,040	7,124	7,842
Exploration expenses, including dry holes	$ 1,153	1,650	1,773	1,408	1,365
Research and development costs	$ 489	630	707	692	736
Total assets	$ 57,854	61,575	62,289	62,963	63,278
Long-term debt	$ 4,717	5,153	4,556	4,669	5,105
Fixed charge coverage ratio (SEC definition)	11.5	7.5	6.5	9.5	9.7
Shareholders' equity	$ 26,627	27,743	28,440	29,443	28,851
Shareholders' equity per share*	$ 30.81	31.95	32.84	34.80	36.84
Average number of shares outstanding *(thousands)**	869,943	864,926	867,959	861,399	816,169
Number of shareholders at year-end *(thousands)*	697	776	865	889	839
Wages, salaries, and employee benefits	$ 5,553	5,832	5,993	5,849	5,550
Average number of employees *(thousands)*	177	180	173	156	150

*Data for 1980 reflect the May 1981 two-for-one stock split.

Review of 1984 Results

Net income of $5,528 million in 1984 was $550 million or 11 percent higher than 1983. On a per share basis, earnings were $6.77, up 17.1 percent from $5.78 per share. During 1984, 64.3 million shares were purchased for the treasury, and this contributed to the per share increase in earnings.

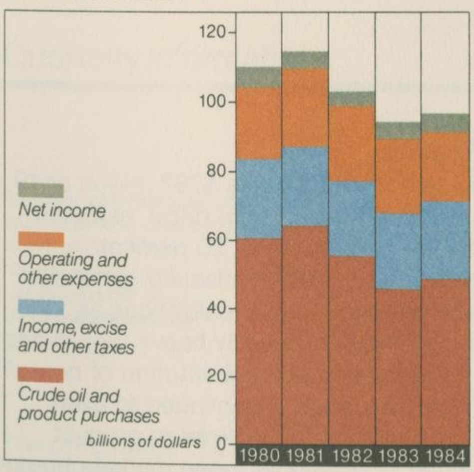
Petroleum and chemical revenues increased in 1984, as demand increased in the first half with the strong economic recovery. However, growth slowed in some areas in the second half of the year, and this, together with lower weather-related demand and continued surplus supply, and excess capacity, placed pressure on prices and margins. Crude prices weakened throughout the year and ended the year in an unsettled condition. Worldwide downstream operations suffered significantly from downward pressures on product prices in most major markets.

Total operating expenses were lower as the increased costs resulting from higher volumes worldwide were more than offset by cost reductions reflecting the continued emphasis on efficiency and productivity improvements. The strengthening of the dollar further reduced the U.S. equivalent of overseas operating costs.

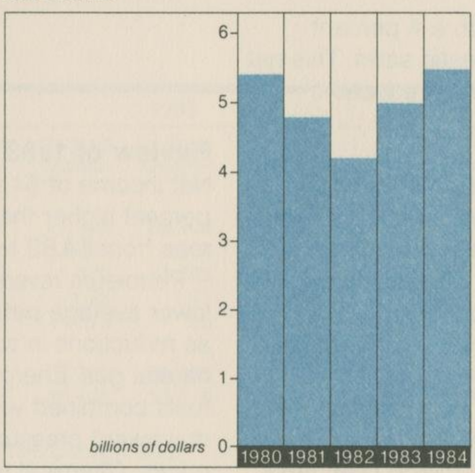
Further business rationalization steps included the decision to withdraw from Exxon Office Systems operations, to discontinue operations at the Aruba refinery and to dispose of additional tankers. 1984 net income included the restoration to earnings of $149 million of prior years' deferred tax provisions.

A reduction in inventory contributed $594 million to net income from the sale of relatively low-cost LIFO inventories compared to $565 million in 1983. The 1984 gains associated with the discontinuance of Aruba operations contributed about 40 percent of these profits.

Revenue and costs



Net income



Exxon's returns

Petroleum and Natural Gas

Exploration and Production

Earnings from this segment were $4,789 million in 1984, a $710 million increase over 1983. Overseas crude oil production increased 12 percent. North Sea production was up 38 thousand barrels per day (kbd), and production in the Far East increased 43 kbd, reflecting higher Malaysian production and the impact of a newly developed Australian field. Crude oil production was about even in the U.S. as efforts to recover additional oil from older, declining fields were offset by reduced Alaska volumes due to the completion of the make up volume associated with the Prudhoe Bay equity redetermination.

Demand for natural gas improved in 1984. Production available for sale rose in the U.S. to 2,485 million cubic feet per day (mcfd), from 2,345 mcfd in 1983. Overseas volumes increased 5 percent to 3,433 mcfd.

Worldwide, depreciation and depletion were up due to higher production and investment, but exploration expenses were lower reflecting lower dry hole costs. Taxes were up reflecting the production volume increase partially offset by lower average effective tax rates abroad and lower windfall profits taxes in the U.S.

Refining and Marketing

Earnings from refining and marketing operations were $357 million in 1984 compared to $1,130 million in 1983. LIFO gains, including those associated with discontinuance of the Aruba operation, were $568 million in 1984, compared to $525 million in 1983.

Highly competitive petroleum markets worldwide served to depress product margins, while the strengthening dollar pushed up the local currency cost of crude supplies in foreign markets.

Petroleum volumes were up in total with a 4 percent increase in foreign markets and flat domestic sales. This net increase partly compensated for the margin reduction.

International Marine

International marine losses were $117 million in 1984 and $126 million in 1983. 1984 continued to be affected by lower international freight rates, declining affiliate demand for transportation services, and higher 1984 charges for vessel disposals which were only partly offset by cost savings from prior restructuring and efficiency improvement steps.

Chemicals

Earnings from worldwide chemical operations totaled $430 million in 1984, an increase of $160 million over 1983. The improvement occurred about equally in the U.S. and foreign operations. Worldwide sales volumes were up 12 percent over 1983 to 15.8 million tons, and margins improved.

Other

Earnings from all other operating segments combined were $102 million, an increase of $65 million from 1983.

A turnaround at Reliance Electric was a major factor, with earnings of $11 million compared to a $58 million loss in 1983. A 10 percent increase in sales due to a stronger economy and positive effects of previous restructuring programs accounted for the change.

Lower earnings in segments of Exxon Enterprises, including provisions for disposition of office systems, were partially offset by a portion of the deferred tax reversal.

Interest Expense

During 1984, the stronger dollar produced significant foreign exchange gains on overseas debt in those countries where the dollar is the functional currency for accounting purposes. These gains and other after-tax changes, including reversal of previous deferred tax provisions, resulted in $284 million of income in 1984 compared to $90 million expense in 1983.

Review of 1983 Results

Net income of $4,978 million in 1983 was $792 million or 19 percent higher than 1982. On a per share basis, earnings rose from $4.82 to $5.78, an increase of 20 percent.

Petroleum revenue dropped in 1983 reflecting generally lower average petroleum product sales realizations as well as reductions in sales volumes, especially heavy fuel oil and natural gas. Energy conservation and substitution of non-oil fuels combined with excess capacity continued to exert downward pressure on crude oil and petroleum product prices. Chemical revenue increased as those markets began to recover in the second half of 1983.

The company benefited from higher crude oil production, particularly in the North Sea. Total expenses declined 3 percent as work force reductions, shutdowns of excess capacity, disposal of unneeded tankers, and other streamlining and rationalization steps had a favorable impact on operating expenses.

Gains from the sale of relatively low-cost LIFO inventories were $565 million, about half the 1982 level.

Petroleum and Natural Gas

Exploration and Production

Exploration and production earnings rose $648 million in 1983, from $3,431 million to $4,079 million. The improvement occurred abroad, due mainly to a 118 thousand barrels per day (kbd) increase in crude oil production volume, from 660 kbd to 778 kbd. With the completion of new facilities in the North Sea toward the end of 1982, crude oil production there rose from 263 kbd to 344 kbd. New installations in Australia and Malaysia boosted Far East production to 283 kbd, from 246 kbd in 1982.

In the U.S., earnings were about even with 1982, as 6 percent (41 kbd) higher crude oil production, mainly the result of a redetermination of the company's equity share in the Prudhoe Bay field, was offset by lower natural gas production and sales due to constrained demand. Provisions for disposition of certain DOE regulatory matters totaled $175 million in 1983. Similar provisions in 1982 were $130 million.

Worldwide exploration expenses were down as a result of both lower costs for services and some reduction in activity.

Refining and Marketing

Refining and marketing earnings of $1,130 million in 1983 were flat compared to 1982. In the U.S., gains from increased sales volumes, other than fuel oil, and operating cost savings were partly negated by a net shrinkage in margins as average selling prices fell more than crude oil supply costs. Abroad, product margins remained under pressure as crude supply costs rose in local currencies because of the stronger dollar. LIFO profits were $471 million below 1982.

International Marine

A weak international marine freight market and declining affiliate requirements caused international marine losses to go from $100 million to $126 million in 1983. Partly compensating were operating cost savings, principally from fleet restructuring activities.

Chemicals

Chemical operations posted $270 million in worldwide earnings in 1983, up from a depressed 1982 total of $93 million. The improvement reflected an 8 percent sales volume growth, related to recovery in worldwide markets, and cost savings from efficiency improvements.

Other

All other operating segments had combined earnings of $37 million in 1983, a significant improvement over the combined loss of $206 million in 1982, which included a $106 million charge for mothballing of the Colony shale oil project. Reduced losses at the company's copper mining operations and several Exxon Enterprises units also contributed to the turnaround.

Interest Expense

Net interest expense was $90 million compared to income of $134 million in 1982, which included $182 million in gains from debt restructuring.

Quarterly Information

	1983					1984				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Summarized financial information										
Sales and other operating revenue (million)	$23,401	22,560	23,106	24,380	93,447	24,498	24,031	23,219	24,125	95,873
Gross profit (million)*	$ 7,852	7,791	8,368	8,749	32,760	8,485	8,597	7,887	7,966	32,935
Net income (million)	$ 1,060	1,075	1,225	1,618	4,978	1,475	1,350	1,275	1,428	5,528
Net income per share	$ 1.22	1.25	1.41	1.90	5.78	1.75	1.63	1.58	1.81	6.77
Dividends per share	$ .75	.75	.80	.80	3.10	.80	.85	.85	.85	3.35
Stock prices										
High	$31.375	35.750	39.375	39.750	39.750	40.000	43.125	45.375	45.500	45.500
Low	$28.500	30.125	33.875	36.125	28.500	36.125	38.000	38.000	41.000	36.125

The price range of Exxon stock is based on the Composite Tape of the several exchanges where Exxon stock is traded. The principal market where Exxon stock (XON) is traded is the New York Stock Exchange, although the stock is traded on most major exchanges.

At February 8, 1985, there were 832,575 holders of record of Exxon stock.

On January 30, 1985, the corporation declared an $.85 dividend per share payable March 11, 1985.

*Gross profit equals sales and other operating revenue less estimated costs associated with products sold.

Taxes

Provision for worldwide taxes increased $0.1 billion in 1984 to $21.9 billion. Income tax expense, including current and deferred taxes, increased $0.3 billion reflecting higher earnings in both domestic and foreign operations. Excise taxes were up $0.1 billion mainly due to higher Australian crude production. Other taxes and duties decreased $0.4 billion, about half of which was due to lower windfall profit taxes in the U.S.

Total taxes in 1983 increased $0.4 billion over 1982. Income taxes were $1.2 billion higher due to increased worldwide earnings. Other taxes and duties decreased $0.8 billion mainly due to lower windfall profit taxes in the U.S.

Total taxes in 1984 were 22 percent of revenue, about the same as in 1983, up from 21 percent in 1982.

Capital and Exploration Expenditures

The capital and exploration program totaled $9.8 billion in 1984 compared to $9.0 billion in 1983.

Worldwide spending for exploration and production development activities totaled $6.9 billion, up $0.9 billion over 1983. U.S. expenditures included acquisition of exploration acreage, particularly in the U.S. offshore, and oil and gas development and enhanced recovery projects. Activity abroad was centered in Europe, Canada, Australia and Malaysia.

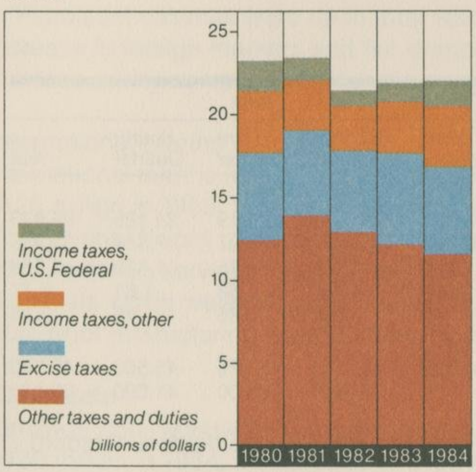
Refining and marketing expenditures totaled $1.4 billion primarily for continued upgrading of refinery units and modernization of retail stations with Exxon's new design and identification system.

Construction expenditures continued on the Cerrejón coal mine in Colombia, and initial coal deliveries were made in early 1985.

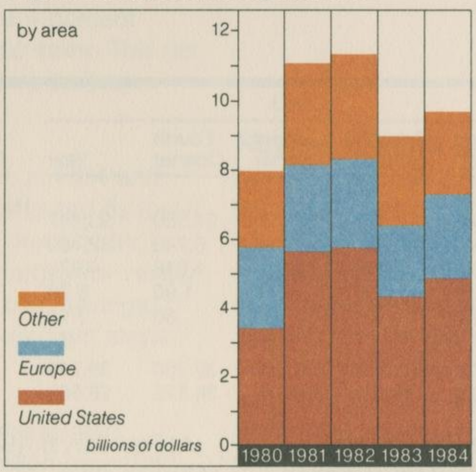
Over 92 percent of 1984 expenditures were invested in energy-related projects, primarily crude oil and natural gas. Chemical expenditures represented a further 3 percent of the total, as construction was completed on a joint-venture linear low-density polyethylene facility, in Saudi Arabia, in which Exxon has a 50 percent interest.

Geographically, over 50 percent, or about $5.0 billion, was invested in U.S. operations, $1.1 billion in Canada and other Western Hemisphere areas, $2.4 billion in Europe and $1.3 billion in other Eastern Hemisphere areas. The functional and geographical mix of the 1984 program reflects a continuation of the pattern of recent years.

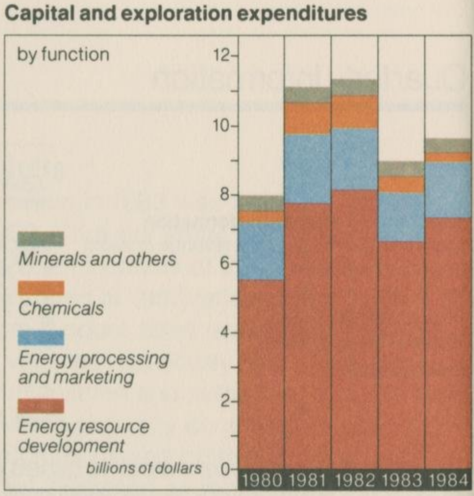
Taxes



Capital and exploration expenditures



Capital and exploration expenditures



Liquidity and Capital Resources

During 1984, funds from operations and other sources, before financing, totaled $11.7 billion, down $1.4 billion from 1983. Total short- and long-term debt increased more than $0.8 billion including $200 million of zero coupon notes issued in the Euromarket at attractive rates, $215 million of industrial revenue bonds and $400 million for a capitalized lease associated with the Odin field offshore Norway. The zero coupon note proceeds were invested in U.S. Government securities pending future cash requirements. Total funds provided totaled $12.5 billion, up $1.2 billion from 1983, when short-term debt was reduced.

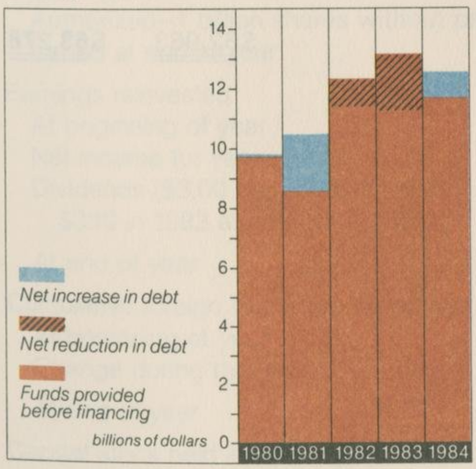
Funds utilized totaled $13.3 billion. Additions to property, plant and equipment were up $0.7 billion to $7.8 billion, $2.6 billion was utilized to acquire 64.3 million shares of Exxon's stock for the treasury, and dividends to Exxon shareholders totaled $2.7 billion. The excess of funds utilized over funds provided resulted in a drawdown of $0.8 billion in cash and marketable securities.

Net working capital totaled $2.0 billion at yearend 1984, a reduction of $1.6 billion as inventories and receivables were reduced in addition to the drawdown in cash and marketable securities. Total debt compared to shareholders' equity plus debt at year-end 1984 was 18 percent, up from 16 percent at year-end 1983. The corporation maintained its strong financial position and flexibility to meet future financial needs. Although the corporation will access financial markets from time to time, internally generated funds are primarily used to cover its financial requirements.

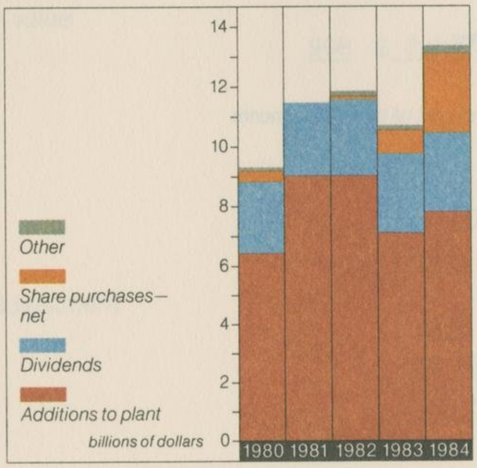
During 1983, funds provided from operations and other sources, before financing activities, totaled $13.1 billion, up $0.8 billion from 1982. Short-term debt was significantly reduced, so total funds provided, after financing activities, amounted to $11.3 billion, down $57 million from 1982. From this total, the corporation used $7.1 billion for additions to property, plant and equipment and $2.7 billion for cash dividends to shareholders. Additionally, $0.8 billion was spent to acquire treasury shares. The excess of funds provided over those utilized resulted in an increase of $0.6 billion in cash and marketable securities to $4.1 billion.

Net working capital at year-end 1983 totaled $3.6 billion, up 7 percent from 1982. This change mainly reflected reductions in short-term debt and accounts payable. Total debt compared to shareholders' equity plus debt at year-end 1983 was 16 percent, down from 20 percent in 1982.

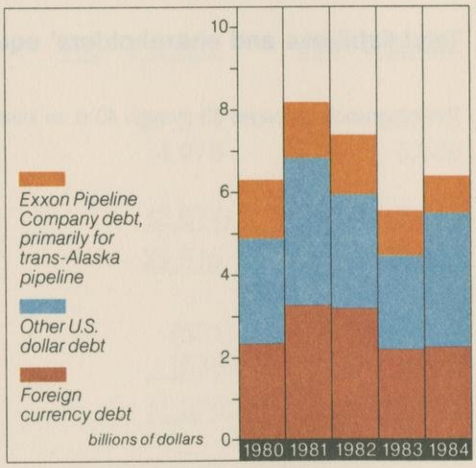
Funds provided



Funds utilized



Total short- and long-term debt



Consolidated Balance Sheet

	Dec. 31, 1983	Dec. 31, 1984
	(millions of dollars)	
Assets		
Current assets		
Cash	$ 2,512	$ 1,384
Marketable securities	1,584	1,906
Notes and accounts receivable, less estimated doubtful amounts	7,900	7,366
Inventories		
Crude oil, products and merchandise	3,598	3,600
Materials and supplies	1,373	1,102
Prepaid taxes and expenses	1,628	1,881
Total current assets	18,595	**17,239**
Investments and advances	1,747	1,743
Property, plant and equipment, at cost, less accumulated depreciation and depletion	40,868	42,776
Other assets, including intangibles	1,753	1,520
Total assets	$62,963	**$63,278**
Liabilities		
Current liabilities		
Notes and loans payable	$ 867	$ 1,277
Accounts payable and accrued liabilities	11,001	10,845
Income taxes payable	3,171	3,143
Total current liabilities	15,039	**15,265**
Long-term debt	4,669	5,105
Annuity reserves and accrued liabilities	3,272	3,478
Deferred income tax credits	9,012	8,948
Deferred income	315	369
Equity of minority shareholders in affiliated companies	1,213	1,262
Total liabilities	33,520	**34,427**
Shareholders' equity	29,443	**28,851**
Total liabilities and shareholders' equity	$62,963	**$63,278**

The information on pages 33 through 40 is an integral part of these statements.

Consolidated Statement of Income

EXXON CORPORATION

	1982	1983	1984
		(millions of dollars)	
Revenue			
Sales and other operating revenue, including excise taxes	$102,059	$93,447	**$95,873**
Earnings from equity interests and other revenue	1,500	1,287	**1,415**
	103,559	94,734	**97,288**
Costs and other deductions			
Crude oil and product purchases	56,084	46,709	48,962
Operating expenses	10,706	10,450	9,903
Selling, general and administrative expenses	5,253	4,948	4,969
Depreciation and depletion	3,333	3,528	4,073
Exploration expenses, including dry holes	1,773	1,408	1,365
Income, excise and other taxes	21,443	21,806	21,879
Interest expense	670	749	400
Income applicable to minority interests	111	158	209
	99,373	89,756	**91,760**
Net Income	$ 4,186	$ 4,978	**$ 5,528**
Per share	$4.82	$5.78	**$6.77**

Consolidated Statement of Shareholders' Equity

	1982		1983		1984	
	Shares	Dollars	Shares	Dollars	Shares	Dollars
			(millions)			
Capital stock						
Authorized—1 billion shares without par value						
Issued at end of year	906	$ 2,822	906	$ 2,822	**906**	**$ 2,822**
Earnings reinvested						
At beginning of year		25,630		27,211		29,515
Net income for year		4,186		4,978		5,528
Dividends ($3.00 per share in 1982, $3.10 in 1983 and $3.35 in 1984)		(2,605)		(2,674)		(2,741)
At end of year		27,211		29,515		**32,302**
Cumulative foreign exchange translation adjustment						
At beginning of year		287		(531)		(1,070)
Change during the year		(818)		(539)		(748)
At end of year		(531)		(1,070)		**(1,818)**
Capital stock held in treasury, at cost						
At beginning of year	(38)	(996)	(40)	(1,062)	(60)	(1,824)
Acquisitions	(3)	(98)	(21)	(784)	(64)	(2,672)
Dispositions	1	32	1	22	1	41
At end of year	(40)	(1,062)	(60)	(1,824)	**(123)**	**(4,455)**
Shareholders' equity						
At end of year		$28,440		$29,443		**$28,851**
Shares outstanding at end of year	866		846		**783**	

The information on pages 33 through 40 is an integral part of these statements.

Consolidated Statement of Funds Provided and Utilized

EXXON CORPORATION

	1982	1983	1984
	(millions of dollars)		
Funds from operations			
Net income			
Accruing to Exxon shareholders	$ 4,186	$ 4,978	$ 5,528
Accruing to minority interests	111	158	209
Costs charged to income not requiring funds			
Depreciation and depletion	3,333	3,528	4,073
Deferred income tax charges	1,789	778	705
Annuity and accrued liability provisions	781	724	384
Dividends received which were less than equity in current earnings of equity companies	(44)	(112)	(70)
Funds provided from operations	10,156	10,054	**10,829**
Funds from other sources, excluding financing activities			
Sales of property, plant and equipment	403	417	227
All other decreases/(increases) in long-term items–net	(317)	322	263
Changes in working capital, excluding cash and debt			
Reduction/(increase)–Notes and accounts receivable	1,299	466	534
–Inventories	1,649	565	269
–Prepaid taxes and expenses	67	813	(253)
Increase/(reduction)–Accounts payable	(1,025)	(692)	(156)
–Income taxes payable	32	1,146	(28)
Funds from other sources, excluding short-term debt, cash and marketable securities	2,108	3,037	**856**
Funds provided before financing	12,264	13,091	**11,685**
Funds from /(used in) financing activities			
Additions to long-term debt	1,526	911	1,363
Reductions in long-term debt	(2,124)	(798)	(927)
Net additions/(reductions) in short-term debt	(285)	(1,880)	410
Funds from/(used in) financing activities	(883)	(1,767)	**846**
Total funds provided, excluding cash items	11,381	11,324	**12,531**
Utilization of funds			
Additions to property, plant and equipment	9,040	7,124	7,842
Cash dividends to Exxon shareholders	2,605	2,674	2,741
Cash dividends to minority interests	105	117	123
Acquisition of Exxon shares–net	66	762	2,631
Funds utilized	11,816	10,677	**13,337**
Increase /(decrease) in cash and marketable securities	$ (435)	$ 647	**$ (806)**

The information on pages 33 through 40 is an integral part of these statements.

Distribution of Earnings and Assets

(millions of dollars)

Segment	1982 Petroleum	1982 Chemicals	1982 Corporate total	1983 Petroleum	1983 Chemicals	1983 Corporate total	1984 Petroleum	1984 Chemicals	1984 Corporate total
Sales and operating revenue									
Non-affiliated	$92,570	$6,049	$102,059	$83,622	$6,392	$93,447	$85,415	$ 6,870	$95,873
Intersegment	3,272	1,210	—	3,361	1,297	—	4,536	1,502	—
Total	$95,842	$7,259	$102,059	$86,983	$7,689	$93,447	**$89,951**	**$ 8,372**	**$95,873**
Operating profit	$ 8,260	$ 47	$ 7,685	$ 9,502	$ 376	$ 9,740	$ 9,789	$ 677	$10,390
Add/(deduct):									
Income taxes	(4,562)	40	(4,164)	(5,021)	(118)	(5,020)	(5,375)	(247)	(5,460)
Minority interests	(97)	(4)	(123)	(115)	(1)	(171)	(155)	(12)	(233)
Earnings of equity companies	921	16	945	804	18	841	835	15	864
Intersegment adjustments	(66)	(6)	—	(87)	(5)	—	(65)	(3)	—
Earnings	$ 4,456	$ 93	4,343	$ 5,083	$ 270	5,390	**$ 5,029**	**$ 430**	**5,561**
Less:									
Unallocated corporate costs			(291)			(322)			(317)
Interest (expense)/ income—net			134			(90)			284
Net income			$ 4,186			$ 4,978			**$ 5,528**
Identifiable assets	$47,598	$5,074	$ 62,289	$46,851	$5,304	$62,963	$46,927	$ 5,246	$63,278
Depreciation and depletion	2,760	180	3,333	3,065	230	3,528	3,572	227	4,073
Additions to plant	6,738	825	9,040	5,531	437	7,124	6,520	240	7,842

Geographic		Sales and other operating revenue: Non-affiliated	Interarea	Total	Earnings	Identifiable assets
1982	**Petroleum and chemicals**					
	United States	$ 25,120	$ 831	$ 25,951	$2,341	$22,711
	Other Western Hemisphere	17,009	2,248	19,257	387	7,756
	Eastern Hemisphere	56,398	1,891	58,289	1,921	20,878
	International marine	92	626	718	(100)	1,280
	Other/eliminations	3,440	(5,596)	(2,156)	(206)	9,664
	Corporate total	$102,059	—	$102,059	$4,343	$62,289
1983	**Petroleum and chemicals**					
	United States	$ 24,360	$ 994	$ 25,354	$2,440	$23,803
	Other Western Hemisphere	16,032	1,912	17,944	274	7,838
	Eastern Hemisphere	49,552	1,100	50,652	2,765	19,439
	International marine	70	414	484	(126)	1,020
	Other/eliminations	3,433	(4,420)	(987)	37	10,863
	Corporate total	$ 93,447	—	$ 93,447	$5,390	$62,963
1984	**Petroleum and chemicals**					
	United States	$ 25,430	$ 1,013	$ 26,443	$2,377	$24,921
	Other Western Hemisphere	16,217	1,449	17,666	299	7,555
	Eastern Hemisphere	50,585	568	51,153	2,900	18,834
	International marine	54	273	327	(117)	809
	Other/eliminations	3,587	(3,303)	284	102	11,159
	Corporate total	**$ 95,873**	—	**$ 95,873**	**$5,561**	**$63,278**

Transfers between business activities or areas are at estimated market prices. International marine results are derived from revenues based on charges to other activities at weighted average industry charter cost. Amortization of capitalized interest is included in interest expense.

Report of Independent Accountants

To the Shareholders of Exxon Corporation

In our opinion, the consolidated financial statements appearing on pages 30 through 40 present fairly the financial position of Exxon Corporation and its subsidiary companies at December 31, 1983 and 1984, and the results of their operations and the changes in their financial position for each of the three years in the period ended December 31, 1984, in conformity with generally accepted accounting principles consistently applied. Our examinations of these statements were made in accordance with generally accepted auditing standards and accordingly included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

153 East 53rd Street
New York, New York
March 4, 1985

Price Waterhouse

Notes to Financial Statements

The accompanying financial statements and the supporting and supplemental material are the responsibility of the management of Exxon Corporation.

The corporation's financial reporting is in agreement with the Organization for Economic Cooperation and Development guidelines for multinational enterprises.

1. Summary of accounting policies

Principles of consolidation The consolidated financial statements include the accounts of those significant subsidiaries owned directly or indirectly more than 50 percent.

Amounts representing the corporation's percentage interest in the underlying net assets of less than majority-owned companies in which a significant equity ownership interest is held are included in "Investments and advances." The corporation's share of the net income of these companies is included in the consolidated statement of income caption "Earnings from equity interests and other revenue."

Investments in all other companies, none of which is significant, are included in "Investments and advances" at cost or less. Dividends from these companies are included in income as received.

Marketable securities Marketable securities are stated at the lower of cost or market.

Inventories Crude oil, products and merchandise inventories are carried at the lower of current market value or cost (generally determined under the last-in, first-out method–LIFO). Costs include all applicable purchase costs and operating expenses, but not general and administrative expenses or research and development costs. Inventories of materials and supplies are valued at cost or less.

Property, plant and equipment The corporation's exploration and production activities are accounted for under the "successful efforts" method. Under this method, costs of productive wells and development dry holes, both tangible and intangible, as well as productive acreage are capitalized and amortized on the unit of production method. Costs of that portion of undeveloped acreage likely to be unproductive, based largely on historical experience, are amortized over the period of exploration. Other exploratory expenditures, including geophysical costs, other dry hole costs and annual lease rentals, are expensed as incurred.

Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit of production method or the straight-line method as applied, generally, to groups of assets. Unit of production rates are based on oil, gas and other mineral reserves estimated to be recoverable from existing facilities. The straight-line method of depreciation is based on estimated asset service life taking obsolescence into consideration.

Maintenance and repairs are expensed as incurred. Major renewals and major improvements are capitalized, and the assets replaced are retired.

Upon normal retirement or replacement, the cost of properties, less salvage, is charged to the allowance for depreciation. Gains or losses arising from abnormal retirements or sales are included in operating results currently.

Income taxes Income tax reductions arising from percentage depletion and U.S. investment credits are included in operating results as realized.

Foreign currency translation Financial Accounting Standards Board Statement No. 52–Foreign Currency Translation, was implemented by using the local currency of the country of operation as the "functional currency" for translating the accounts of the majority of foreign petroleum refining and marketing as well as chemical operations, except for those located in highly inflationary economies. Local currency was also used for exploration and production operations where the production is consumed locally, such as in Australia, Canada, the United Kingdom and continental Europe. For other foreign operations, principally exploration and production operations in Norway, Malaysia and the Middle East, together with operations in highly inflationary economies, the U.S. dollar was used as the functional currency.

2. Miscellaneous financial information

Cash included time deposits of $1,764 million at the end of 1983 and $722 million at the end of 1984.

Estimated doubtful notes and accounts receivable were $171 million at the end of 1983 and $165 million at the end of 1984.

Accumulated depreciation and depletion totaled $20,917 million at the end of 1983 and $22,091 million at the end of 1984.

Research and development costs totaled $707 million in 1982, $692 million in 1983 and $736 million in 1984.

Aggregate foreign exchange transaction losses included in determining net income totaled $107 million in 1982, and $56 million in 1983. 1984 results included a gain of $109 million.

Marketable securities at year-end 1983 and 1984 were carried at cost which was $20 million and $36 million, respectively, less than their fair market value.

Interest capitalized in 1982, 1983 and 1984, in conformity with Financial Accounting Standards Board Statement No. 34–Capitalization of Interest Cost, as modified by Statement No. 71, was $207 million, $271 million and $268 million, respectively.

Net income included $1,092 million in 1982, $565 million in 1983 and $594 million in 1984 attributed to the sale of relatively low-cost crude and products obtained from drawdowns of LIFO inventory quantities.

In 1983 and 1984, treasury shares were utilized in connection with stock options exercised, bonuses and stock appreciation rights under incentive programs.

3. Investments and advances

Components of investments and advances were:

	1983	1984
	(millions of dollars)	
In less than majority-owned companies		
Carried at equity in underlying assets		
Investments	$1,218	$1,218
Advances	7	35
	1,225	1,253
Carried at cost or less	111	106
	1,336	1,359
Long-term receivables and miscellaneous investments at cost or less	411	384
Total	$1,747	**$1,743**

4. Equity company information

The summarized financial information below includes those less than majority-owned companies, except Aramco, for which Exxon's share of net income is included in consolidated net income (see Note 1, page 34). Exxon's earnings from these companies consist in large part of earnings from natural gas production and distribution companies in the Netherlands and West Germany.

These data exclude Aramco, in which the government of Saudi Arabia acquired during 1980 the beneficial interest in substantially all of the assets and operations. Aramco continues to have access to a significant volume of Saudi Arabian crude oil. Exxon's share of earnings of Aramco, after application of adjustments, totaled $62 million, $8 million and $77 million in 1982, 1983 and 1984, respectively.

	1982		1983		1984	
	Total	Exxon share	Total	Exxon share	Total	Exxon share
			(millions of dollars)			
Total revenues, of which 15% in each of 1982, 1983 and 1984 were from companies included in the Exxon consolidation	$21,999	$6,816	$20,707	$6,372	$20,278	$6,181
Earnings before income taxes	$ 3,694	$1,660	$ 3,594	$1,558	$ 3,283	$1,392
Less: Related income taxes	(1,740)	(777)	(1,698)	(725)	(1,477)	(605)
Earnings	1,954	883	1,896	833	1,806	787
Less: Interest expense	(510)	(169)	(334)	(110)	(310)	(96)
Related income taxes on interest expense	227	74	156	50	148	45
Net income	$ 1,671	$ 788	$ 1,718	$ 773	**$ 1,644**	**$ 736**
Current assets	$ 7,401	$2,476	$ 6,701	$2,133	$ 6,006	$1,969
Property, plant and equipment, less accumulated depreciation	5,907	2,327	5,753	2,241	5,869	2,302
Other long-term assets	610	261	838	345	864	390
Total assets	13,918	5,064	13,292	4,719	12,739	4,661
Short-term debt	2,968	964	2,275	732	1,703	563
Other current liabilities	4,675	1,739	4,062	1,506	3,804	1,495
Long-term debt	2,387	832	2,544	866	2,632	934
Other long-term liabilities	999	417	984	402	1,143	455
Net assets	$ 2,889	$1,112	$ 3,427	$1,213	**$ 3,457**	**$1,214**

5. Investment in property, plant and equipment

	Investment Dec. 31, 1983	Additions–1984			Investment Dec. 31, 1984	
	Less accumulated depreciation and depletion	(millions of dollars) United States	Foreign	Total	At cost	Less accumulated depreciation and depletion
Petroleum and natural gas						
Exploration and production	$23,402	$3,351	$1,919	$5,270	$37,031	$25,057
Refining and marketing	7,920	379	866	1,245	13,707	7,738
International marine	934	—	—	5	1,751	771
Total petroleum and natural gas	32,256	3,730	2,785	6,520	52,489	33,566
Other energy related	3,053	29	622	651	4,020	3,587
Chemicals	3,492	109	131	240	5,302	3,353
Other	2,067	205	226	431	3,056	2,270
Total	**$40,868**	**$4,073**	**$3,764**	**$7,842**	**$64,867**	**$42,776**

6. Long-term debt

At December 31, 1984, long-term debt consisted of $3,765 million due in U.S. dollars and $1,340 million representing the U.S. dollar equivalent at year-end exchange rates of amounts payable in foreign currencies. These amounts exclude that portion of long-term debt, totaling $381 million, which matures within one year and is included in current liabilities. Long-term borrowings at year-end 1984 are summarized below, with weighted average interest rates in parentheses.

		(millions of dollars)	
Exxon Corporation			
Floating rate pollution-control revenue bonds–due 2012, 2013, 2014 and 2022		$ 325	
Other obligations–due 1986-2022		93	$ 418
Exxon Pipeline Company			
8⅞% guaranteed debentures–due 2000		216	
5.50% marine terminal revenue bonds–due 2007		250	
8¼% guaranteed debentures–due 2001		173	
9% guaranteed debentures–due 2004		166	
Other obligations–due 1987-2008		68	873
Other consolidated subsidiaries			
Capitalized lease obligations*			
United States dollars	$405		
Other currencies	197	602	
United States dollars (9.4%)		2,068	
British pounds (8.6%)		478	
Hong Kong dollars (9.0%)		271	
Canadian dollars (9.9%)		264	
Norwegian kroner (10.2%)		53	
French francs (11.9%)		38	
Finnish markkaa (11.0%)		10	
Other currencies (63.7%)		30	3,814
Total long-term debt			**$5,105**

*At an average imputed interest rate of 10.7%.

The amounts of long-term debt maturing, together with sinking fund payments required, in each of the four years after December 31, 1985, in millions of dollars, are: 1986–$393; 1987–$722; 1988–$395; 1989–$610.

During 1984, an affiliate issued at a discount $1,800 million of zero coupon notes due in 2004. The affiliate received $199 million as proceeds from these notes. No payment of interest is provided for by zero coupon notes. At maturity, the $1,800 million will be paid to note holders. At December 31, 1984, these notes were included in the United States dollars category of other consolidated subsidiaries as follows:

	(millions of dollars)
Principal	$1,800
Less unamortized discount	(1,598)
Total	$ 202

During 1982, an affiliate issued at a discount $771 million of deferred interest debentures due in 2012. There will be no payment of interest on the debentures prior to maturity. At maturity, the holder of each debenture will be entitled to a payment of interest of $730 in addition to the $270 principal amount of the debentures. At December 31, 1984, these debentures were included in the United States dollars category of other consolidated subsidiaries as follows:

	(millions of dollars)
Principal	$771
Less unamortized discount	(652)
Total	$119
Deferred interest	$ 24

In 1982, debt totaling $515 million was removed from the balance sheet through the creation of an irrevocable trust. The principal and interest of the funds deposited with the trustee will be sufficient to fund the scheduled principal and interest payment of these debt issues. During 1983, $51 million of these debt issues were retired, leaving a balance of $464 million at year-end 1984.

7. Leased facilities

At December 31, 1984, the corporation and its consolidated subsidiaries held non-cancelable operating charters and leases covering tankers, service stations and other properties for which minimum lease commitments were as follows:

	Minimum commitment after reduction for related rental income		Related rental income
	Tankers	Other	
	(millions of dollars)		
1985	$147	$328	$ 61
1986	52	210	61
1987	19	113	52
1988	18	72	46
1989	13	59	44
1990 and beyond	15	163	352

Net rental expense for 1982, 1983 and 1984 totaled $1,245 million, $1,235 million and $1,204 million, respectively, after being reduced by related rental income of $72 million, $69 million and $86 million, respectively.

8. Annuity and other post-employment benefits

Exxon and many of its affiliates have retirement plans which cover substantially all of their employees. Benefits are paid from funds previously provided to trustees and insurance companies or are paid directly by the corporation or its affiliates and charged against book reserves previously provided.

Charges to consolidated income for the cost of such annuity plans, based on the entry age normal actuarial cost method, were $557 million, $520 million, and $328 million for the years 1982, 1983, and 1984, respectively. Such charges were based on assumed average future rates of return on assets as follows: U.S. plans—7.9 percent in 1982, 8.3 percent in 1983, and 10.0 percent in 1984; foreign plans—various rates from plan to plan, from 4 percent to 15 percent. Other actuarial assumptions relate to future salary and wage escalation and company experience regarding changes in the employee population. The effect of changes in actuarial assumptions and variances between actual and assumed experience were amortized over 12.5 years in 1984 in the United States, representing the average remaining service life of employees. Prior to 1984, the corporation used a twenty-year period for such amortization. Various amortization periods are used in the foreign plans. The reduction in 1984 pension cost was largely due to assumed higher rates of return on assets, reflecting current and anticipated long-term performance.

In addition to providing annuity benefits, the company and many of its affiliates provide certain health care and life insurance benefits for retired employees. Employees may become eligible for those benefits if they retire with annuitant status. These benefits are provided primarily through premium payments to insurance companies or contributions to trust funds, based on the benefits paid during the year. The company recognizes the cost of providing these benefits by expensing the annual insurance premiums and trust fund contributions, which were $61 million in 1984.

The following table shows the status of the U.S. and foreign annuity plans as of the end of 1983 and 1984.

	U.S. Plans		Foreign Plans	
Annuity plans status	Dec. 31, 1983	Dec. 31, 1984	Dec. 31, 1983	Dec. 31, 1984
	(millions of dollars)			
Estimated amount of assets* required to provide funds for future payment of:				
Projected benefits based on employment service to date and present pay levels				
Vested	$3,248	$2,773	$1,903	$1,991
Non-vested	156	136	147	148
	3,404	2,909	2,050	2,139
Additional amounts related to projected pay increases	879	719	1,002	832
Total	4,283	3,628	3,052	2,971
Actual amount of assets available for benefits				
Funded assets (market values)	4,679	4,789	1,742	1,799
Book reserves	124	137	1,106	959
Total	4,803	4,926	2,848	2,758

*Based on the assumed rates of return previously noted.

9. Additional working capital data

Consolidated notes and accounts receivable include:

	1983	1984
	(millions of dollars)	
Trade, less reserves of $157 million and $152 million	$6,690	$ 6,311
Other, less reserves of $14 million and $13 million	1,210	1,055
	$7,900	**$7,366**

Notes, loans, accounts payable and accrued liabilities include:

	1983	1984
	(millions of dollars)	
Bank loans	$ 552	$ 747
Commercial paper	1	33
Long-term debt due within one year	279	381
Other	35	116
Total notes and loans payable	867	1,277
Trade payables	6,761	7,069
Obligations to equity companies	1,109	547
Accrued taxes other than income taxes	1,477	1,320
Other	1,654	1,909
Total accounts payable and accrued liabilities	11,001	10,845
	$11,868	**$12,122**

Unused lines of credit for short-term financing available at December 31, 1984, totaled approximately $3,700 million.

10. Litigation

Prior to January 28, 1981, Exxon's United States petroleum operations were subject to Department of Energy (DOE) regulations. The DOE has issued Notices of Probable Violation or filed lawsuits alleging that, in various periods since September 1973, Exxon priced certain crude oil, natural gas liquids, and refined petroleum products in excess of levels permitted by DOE regulations.

Although some of the regulations were vague and ambiguous and in many cases the DOE sought to apply them on a retroactive basis, Exxon attempted in good faith to comply with these regulations and believes it correctly applied them. While Exxon has been successful in defending its position in many of these allegations and lawsuits, a number remain unresolved.

During 1983, an adverse lower court decision was announced in a lawsuit between Exxon and the DOE regarding crude oil produced from the Hawkins Field Unit in East Texas. The decision states that between 1975 and 1981 the unit interest owners received $895.5 million in revenue to which they were not entitled under price-control regulations and holds Exxon liable as unit operator. In addition, the decision requires interest from the dates of the alleged violations through resolution of the litigation. At year-end 1984, accrued interest amounted to approximately $1,005 million. Exxon's position is that if any amount is required to be paid, Exxon should be responsible only for its percentage share in the Hawkins Field Unit, which is approximately 67 percent. On this basis, and after allowing for the recovery of applicable windfall profit tax, severance tax and income tax, the decision represents a potential net cost to Exxon of about $605 million, including interest, as of year-end 1984. If, contrary to its position, Exxon is required to make payments on behalf of the more than 2,300 other interest owners in the Hawkins Field Unit, such payments will increase Exxon's net cost to the extent Exxon is unable to recover such payments from the other interest owners.

Exxon believes the lower court decision in this case is incorrect and unfair and has appealed. On June 17, 1983, the corporation was granted a stay of the judgment pending final disposition of all appeals. No appellate decision has yet been rendered.

In other litigation with the DOE and unresolved administrative proceedings, the DOE has alleged overpricing of approximately $535 million. Since some of the alleged overpricing relates to activities which continued beyond the periods covered by these allegations, with possible further liability for interest in some instances, cumulative amounts may be higher than those alleged by the DOE.

The corporation believes its positions are correct and continues to defend them in all of these DOE matters. Nevertheless, recognizing the varying interpretations which the courts and regulatory bodies have rendered and may render in the future in these cases and in other related matters, including cases not involving Exxon, the corporation has charged approximately $440 million, after tax, against earnings.

Claims for substantial amounts have been made against Exxon and certain of its consolidated subsidiaries in other pending lawsuits, the outcome of which will not be materially important in relation to the consolidated financial position of the corporation in the opinion of its general counsel.

11. Other contingencies

The corporation and certain of the consolidated subsidiaries were contingently liable at December 31, 1984, for $650 million for guarantees primarily relating to notes, loans and performance under contracts. This includes $213 million representing guarantees of foreign excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements.

Additionally, the corporation and its affiliates have numerous long-term sales commitments in their various business activities, all of which are expected to be fulfilled with no adverse consequences material to the corporation's consolidated financial position.

The Controller General of Venezuela has filed income tax claims of approximately $275 million for the period January 1, 1970, to March 18, 1971, against the corporation's affiliates operating in Venezuela in that period. The claims relate to alleged retroactive application of tax export values established by the government on March 8, 1971, to be effective from March 18, 1971. The corporation and its affiliates believe that there is no legal foundation for the claims. The affiliates are defending their interest vigorously, utilizing the applicable procedures established under Venezuelan law.

The operations and earnings of the corporation and its affiliates throughout the world have been and may in the future be affected from time to time in varying degree by political developments and laws and regulations, such as forced divestiture of assets; restrictions on production, imports and exports; price controls; tax increases and retroactive tax claims; expropriation of property; cancellation of contract rights; and pollution controls. Both the likelihood of such occurrences and their overall effect upon the corporation vary greatly from country to country and are not predictable.

12. Stock option plans

The 1983 Incentive Program makes provision for the grant of options on a maximum of 13,000,000 shares of corporation stock over the five-year period ending May 31, 1988. As under earlier plans, options may be granted at prices not less than 100 percent of market value on the date of grant. Options granted are exercisable after one year of continuous employment following date of grant.

The 1983 plan also provides for granting stock appreciation rights to holders of options under present and past plans, which permit them to surrender exercisable options in exchange for shares of the corporation's stock having an aggregate market value, at the time of surrender, equal to the difference between the option price and market value of shares covered by surrendered options, or to receive such difference in cash under the conditions provided for in the stock appreciation rights.

Outstanding options for 12,813,132 and 13,004,820 shares at December 31, 1983 and 1984, respectively, had stock appreciation rights attached. In anticipation of settlement of such rights at market value of the shares covered by the options to which attached, $39 million was charged to earnings in 1983 and $54 million was charged to earnings in 1984. The exercise of such rights releases the corporation from the obligation of providing stock under the option at the option price.

Changes that occurred during 1984 in options outstanding are summarized below.

	1973 plan	1978 plan	1983 plan
		number of shares	
Outstanding at December 31, 1983	1,543,647	8,850,035	2,422,450
Granted at $43.50 per share	—	—	2,559,950
Less: Exercised	243,434	513,297	1,800
Expired	800	5,300	34,050
Surrendered	585,202	966,079	21,300
Outstanding at December 31, 1984	714,211	7,365,359	4,925,250
Available for grant after December 31, 1984	None	None	8,051,650

The average option price per share of the options outstanding at December 31, 1984, for the plans was $35.58.

The effect on reported earnings per share from the assumed exercise of stock options outstanding at year-end 1982, 1983 or 1984 would be insignificant.

13. Bonus plan

The 1978 and the 1983 Incentive Programs make provision for grants of bonuses in respect of each of the five years beginning with 1978 and 1983, respectively, which are not to exceed 3 percent of the amount by which net income in a given year exceeds 6 percent of capital invested (as defined in the plan). Bonuses may be granted to eligible employees of the corporation and of those affiliates at least 95 percent owned. Bonuses may be granted in cash, shares of the corporation's stock or earnings bonus units, which are rights entitling the grantee to receive on the settlement date, with certain limitations, an amount of cash equal to the corporation's cumulative earnings per share as reflected in its quarterly earnings statements as initially published, commencing with earnings for the first full quarter following the date of grant to and including the last full quarter preceding the date of settlement. Bonuses other than units may be paid in cash or shares of the corporation's stock in full at the time of allotment or retirement or in annual installments. Any unpaid amounts are subject to certain forfeiture provisions contained in the plan.

Grants in cash and shares of the corporation's stock are charged to earnings in the year of grant. Amounts earned under earnings bonus units are accrued as they occur. Total charges to earnings in 1982, 1983 and 1984 were $26 million, $31 million and $35 million, respectively, reflecting grants substantially less than the maximum permitted under the plan.

14. Income, excise and other taxes

	1982 United States	1982 Foreign	1982 Total	1983 United States	1983 Foreign	1983 Total	1984 United States	1984 Foreign	1984 Total
					(millions of dollars)				
Income taxes									
Federal or foreign – current	$ 716	$ 1,204	$ 1,920	$1,030	$ 2,676	$ 3,706	$ 992	$ 3,353	$ 4,345
– deferred – net	224	1,322	1,546	165	777	942	457	271	728
U.S. tax on foreign operations	26		26	31		31	(118)		(118)
	966	2,526	3,492	1,226	3,453	4,679	**1,331**	**3,624**	**4,955**
State	86		86	92		92	115		115
Total income tax expense	1,052	2,526	3,578	1,318	3,453	4,771	1,446	3,624	5,070
Excise taxes	773	4,113	4,886	1,047	3,839	4,886	1,205	3,814	5,019
Other taxes and duties*	2,530	10,449	12,979	2,117	10,032	12,149	1,843	9,947	11,790
Total	$4,355	$17,088	$21,443	$4,482	$17,324	$21,806	**$4,494**	**$17,385**	**$21,879**
Memo:									
Exxon share of income taxes of equity companies (not included above)	$ 9	$ 788	$ 797	$ 13	$ 727	$ 740	$ 16	$ 577	$ 593
Effective income tax rate, including income taxes of equity companies and state income taxes – percent	35.5	59.2	51.1	41.3	57.4	52.5	44.7	53.3	50.6

Reconciliation between income tax expense and a theoretical U.S. tax computed by applying a rate of 46 percent to earnings before income taxes:

	1982 United States	1982 Foreign	1982 Total	1983 United States	1983 Foreign	1983 Total	1984 United States	1984 Foreign	1984 Total
Earnings before federal and foreign income taxes	$2,821	$ 4,857	$ 7,678	$3,046	$ 6,611	$ 9,657	$3,402	$ 7,081	$10,483
Theoretical tax	$1,298	$ 2,234	$ 3,532	$1,401	$ 3,041	$ 4,442	$1,565	$ 3,257	$ 4,822
Adjustments for foreign taxes in excess of theoretical U.S. tax		292	292		412	412		367	367
Deferred tax on undistributed earnings							(149)		(149)
U.S. investment tax credit	(259)		(259)	(173)		(173)	(149)		(149)
U.S. tax on foreign operations	26		26	31		31	31		31
Research credit	(26)		(26)	(19)		(19)	(7)		(7)
Other	(73)		(73)	(14)		(14)	40		40
Federal or foreign income tax expense	$ 966	$ 2,526	$ 3,492	$1,226	$ 3,453	$ 4,679	$1,331	$ 3,624	$ 4,955

Net deferred income tax expense, above, represents the sum of tax effects related to timing differences, generally between amounts reportable currently for tax purposes and related amounts included in earnings for financial reporting, as follows:

Tax effects of timing differences for:	1982	1983	1984 United States	1984 Foreign	1984 Total
			(millions of dollars)		
Depreciation	$1,313	$ 865	$ 494	$ 133	$ 627
Inventories	106	166	(11)	(13)	(24)
Intangible development costs	630	303	89	196	285
Other	(503)	(392)	(115)	(45)	(160)
Net deferred income taxes	$1,546	$ 942	$ 457	$ 271	$ 728

Income taxes do not include $56 million, $122 million and $52 million in 1982, 1983 and 1984, respectively, of state franchise taxes which are based on income.

Possible taxes, beyond those provided, on remittances of undistributed earnings of subsidiary companies, after giving consideration to amounts which are reinvested indefinitely, are not expected to be material.

*Includes U.S. "windfall profit" tax of $1,377 million, $853 million and $692 million in 1982, 1983 and 1984, respectively.

Supplemental Information on Oil and Gas Exploration and Production Activities

This section provides historical revenue, cost, operating earnings and reserve information regarding Exxon's oil and gas exploration and production operations during 1982, 1983 and 1984. This information was developed in conformance with Financial Accounting Standards Board Statement No. 19—Financial Accounting and Reporting by Oil and Gas Producing Companies, as modified by Statements No. 25 and No. 69. For most of this section, the information is shown for each of the six major geographic areas in which the company operates. Additional information on exploration and production activities can be found on pages 5 through 11.

The following pages (pages 42 and 43) show the company's crude oil and natural gas reserves at year-end 1982, 1983 and 1984 and a summary of the major changes to these reserves—such as new discoveries and production—during these years. These reserves are shown separately for consolidated affiliates, for the company's proportional interest in proved reserves of equity companies and for supplies available under long-term agreements with foreign governments. Additional production information may be found on page 50.

The second set of tables, on page 44, provides consolidated oil and gas exploration and production costs that were capitalized at the end of 1983 and 1984 and costs which were incurred by the exploration and production function during 1982, 1983 and 1984. The company's proportional interests of capitalized costs and costs incurred by equity companies are shown separately.

The fifth table, on page 45, summarizes the earnings of the oil and gas exploration and production function for 1982, 1983 and 1984.

The data discussed on pages 42 through 45 are historical information and are consistent with the other financial and operating information published by Exxon. However, the tables on pages 46 and 47, concerning the "standardized measure of discounted future net cash flows," depart significantly from historical accounting practices. Exxon has taken exception to the disclosure of these data as required by Statement No. 69.

Discussion of Standardized Measure

The standardized measure data on pages 46 and 47 are based upon estimated volumes of oil and gas reserves as well as forecasts of future production rates over the lives of the reserves. While, in management's judgment, the quantities are reasonable, there is no methodology or certification process which would permit independent verification of such volumes and rates. The standardized measure data are also based upon prices and costs at December 31, 1984, with no provision for deducting exploration expenses, amortization of acquisition costs (bonus payments), depreciation of capitalized production investments, purchase costs of royalty oil and gas or other similar payments to governments. In addition, an arbitrary 10 percent discount rate (which does not necessarily represent a cost of capital, a borrowing cost, or reflect political risk) is used in determining present values.

Thus, the data set forth on pages 46 and 47 should not be interpreted as necessarily representing current profitability or amounts Exxon will receive, or costs which will be incurred, or the manner in which oil and gas will be produced from the respective oil and gas reserves. Actual future selling prices and related production costs, development costs, production schedules, and reserves and their classifications may differ significantly from data assumed or portrayed.

As a result of these concerns, the company does not believe that the presentation on pages 46 and 47 is the proper basis to reflect the results of oil and gas operations. However, the company believes that the table on page 45, when used in conjunction with the other historical data in this section, provides relevant information to assist in an evaluation of the company's oil and gas exploration and production operations and in the development of reasonable interpretations concerning the value of the oil and natural gas reserves, and the levels of future earnings and cash flows.

Oil and Gas Reserves*

The following information, describing changes during the years and balances of oil and gas reserves at year-end 1982, 1983 and 1984, is presented in accordance with Financial Accounting Standards Board (FASB) Statement No. 19–Financial Accounting and Reporting by Oil and Gas Producing Companies, as amended by Statements No. 25 and No. 69. The definitions of proved reserves used in these tables are those developed by the Department of Energy for its Financial Reporting System and adopted by the FASB.

Proved reserves are the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. They include some reserves which may or may not be producible within the lives of existing agreements. In some cases, substantial new investments in additional wells and related facilities will be required to recover these proved reserves, including a major pipeline in the case of Alaskan gas reserves.

Proved reserves include 100 percent of each majority-owned affiliate's participation in proved reserves and Exxon's ownership percentage of the proved reserves of equity companies, but exclude royalties and quantities due others when produced. Gas reserves exclude the gaseous equivalent of liquids expected to be removed from the gas on leases, at field facilities and at gas processing plants. These liquids are included in the category net proved reserves of crude oil and natural gas liquids.

Net proved developed reserves are those volumes which

	Total Worldwide	United States	Canada	Other Western Hemisphere	Europe	Middle East and Africa	Australia and Far East
Crude oil and natural gas liquids				(millions of barrels)			
Net proved developed and undeveloped reserves							
Beginning of year 1982	**6,157**	**2,822**	**489**	**36**	**1,646**	**7**	**1,157**
Revisions of previous estimates	440	160	141	(13)	131	1	20
Improved recovery	48	48	—	—	—	—	—
Extensions, discoveries, and other additions	201	76	1	2	108	14	—
Production	(499)	(270)	(35)	(4)	(105)	(2)	(83)
End of year 1982	**6,347**	**2,836**	**596**	**21**	**1,780**	**20**	**1,094**
Revisions of previous estimates	224	44	13	7	88	2	70
Improved recovery	59	59	—	—	—	—	—
Extensions, discoveries, and other additions	405	128	156	2	118	—	1
Production	(557)	(285)	(33)	(5)	(135)	(2)	(97)
End of year 1983	**6,478**	**2,782**	**732**	**25**	**1,851**	**20**	**1,068**
Revisions of previous estimates	155	67	16	3	(6)	—	75
Improved recovery	104	61	43	—	—	—	—
Extensions, discoveries, and other additions	327	90	152	2	69	—	14
Production	(590)	(285)	(34)	(6)	(150)	(2)	(113)
End of year 1984	**6,474**	**2,715**	**909**	**24**	**1,764**	**18**	**1,044**
Net proved developed reserves (included above)							
Beginning of year 1982	3,636	2,185	408	19	470	3	551
End of year 1982	3,863	2,134	527	19	624	3	556
End of year 1983	3,962	2,115	509	19	685	5	629
End of year 1984	3,924	2,030	530	21	597	3	743
Proportional interest in proved reserves of equity companies							
End of year 1982	75	—	—	—	50	—	25
End of year 1983	57	—	—	—	47	—	10
End of year 1984	69	—	—	—	58	—	11
Supplies available under long-term agreements with foreign governments							
End of year 1982	541	—	—	—	—	541	—
Received during the year 1982	8	—	—	—	—	8	—
End of year 1983	525	—	—	—	—	525	—
Received during the year 1983	9	—	—	—	—	9	—
End of year 1984	509	—	—	—	—	509	—
Received during the year 1984	8	—	—	—	—	8	—
Oil sands reserves							
End of year 1982	187	—	187	—	—	—	—
End of year 1983	179	—	179	—	—	—	—
End of year 1984	172	—	172	—	—	—	—
Worldwide net proved developed and undeveloped reserves (including supplies and oil sands)							
End of year 1982	7,150	2,836	783	21	1,830	561	1,119
End of year 1983	7,239	2,782	911	25	1,898	545	1,078
End of year 1984	7,224	2,715	1,081	24	1,822	527	1,055

*See footnote on page 43.

are expected to be recovered through existing wells with existing equipment and operating methods. Undeveloped reserves are those volumes which are expected to be recovered as a result of future investments, pending or in-progress, to drill new wells, to recomplete existing wells, and/or to install facilities to collect and deliver the production from existing and future wells.

The United States net proved oil reserves include oil attributable to a secondary recovery program which is not yet in operation in the Prudhoe Bay field in Alaska and net proved natural gas reserves include 9,294 billion cubic feet of reserves in Alaska. Reserves attributable to oil and gas discoveries reported in the Mackenzie Delta region of Canada, and certain oil and gas discoveries elsewhere in the U.S. and Canada and in Malaysia, Thailand, Indonesia, China, Australia, the U.K., the Netherlands and Norway, were not considered proved as of year-end 1984 due to geological, technological and economic uncertainties and therefore are not included in the tabulation.

Crude oil and natural gas liquids and natural gas production quantities shown are the net volumes withdrawn from Exxon's oil and gas reserves. These differ from the quantities of oil and gas delivered for sale by the producing function, as reported on page 50, due to inventory changes and, especially in the case of natural gas, volumes consumed and/or vented. Such quantities were not significant for crude oil and natural gas liquids. For natural gas, such quantities amounted to approximately 190 billion cubic feet in 1982, 183 billion cubic feet in 1983, and 157 billion cubic feet in 1984.

	Total Worldwide	United States	Canada	Other Western Hemisphere	Europe	Middle East and Africa	Australia and Far East
Natural gas				(billions of cubic feet)			
Net proved developed and undeveloped reserves							
Beginning of year 1982	**27,785**	**16,924**	**1,293**	**280**	**5,998**	**5**	**3,285**
Revisions of previous estimates	1,538	(45)	103	(13)	689	—	804
Improved recovery	36	36	—	—	—	—	—
Extensions, discoveries, and other additions	920	581	24	3	312	—	—
Production	(1,603)	(1,035)	(70)	(29)	(349)	(1)	(119)
End of year 1982	**28,676**	**16,461**	**1,350**	**241**	**6,650**	**4**	**3,970**
Revisions of previous estimates	1,825	1,323	7	4	506	—	(15)
Improved recovery	9	9	—	—	—	—	—
Extensions, discoveries, and other additions	1,307	586	9	3	703	—	6
Production	(1,516)	(946)	(66)	(28)	(365)	(1)	(110)
Sales of minerals-in-place	(1,022)	—	—	—	—	—	(1,022)
End of year 1983	**29,279**	**17,433**	**1,300**	**220**	**7,494**	**3**	**2,829**
Revisions of previous estimates	566	68	19	19	463	1	(4)
Improved recovery	36	20	16	—	—	—	—
Extensions, discoveries, and other additions	1,526	1,340	6	2	171	—	7
Production	(1,622)	(977)	(62)	(28)	(440)	(1)	(114)
End of year 1984	**29,785**	**17,884**	**1,279**	**213**	**7,688**	**3**	**2,718**
Net proved developed reserves (included above)							
Beginning of year 1982	22,906	15,886	1,021	208	3,097	5	2,689
End of year 1982	22,498	15,378	1,153	185	3,280	4	2,498
End of year 1983	23,010	16,366	1,127	163	3,251	3	2,100
End of year 1984	23,160	16,194	1,100	157	3,568	3	2,138
Proportional interest in proved reserves of equity companies							
End of year 1982	15,666	—	—	—	15,441	—	225
End of year 1983	17,541	—	—	—	17,441	—	100
End of year 1984	17,214	—	—	—	17,123	—	91
Worldwide net proved developed and undeveloped reserves							
End of year 1982	44,342	16,461	1,350	241	22,091	4	4,195
End of year 1983	46,820	17,433	1,300	220	24,935	3	2,929
End of year 1984	46,999	17,884	1,279	213	24,811	3	2,809

*These and other tables, as noted, in this report do not include reserve, supply, cost and other data relating to Exxon's interest in the Arabian American Oil Company (Aramco) because the government of Saudi Arabia prohibits the disclosure of confidential information under a directive issued by the Minister of Petroleum and Mineral Resources bearing Number 1030/Z. During 1980, the government acquired the beneficial interest in substantially all of Aramco's assets and operations. However, Aramco continues to have access to a significant volume of Saudi Arabian crude oil.

Oil and Gas Exploration and Production Costs

The tables below summarize the capitalized costs at December 31, 1983 and 1984 and certain costs incurred in oil and gas producing activities during 1982, 1983 and 1984. The definitions of terms used in developing these tables are consistent with those described in Financial Accounting Standards Board Statement No. 19–Financial Accounting and Reporting by Oil and Gas Producing Companies.

The amounts shown in the table for total capitalized costs less the accumulated depreciation are $2,773 million less in 1983 and $2,881 million less in 1984 than those reported as investment in property, plant and equipment–exploration and production in Note 5 on page 36 mainly due to excluding from the data certain transportation and research assets and assets related to the oil sands operations of Syncrude in Canada and including in the data accumulated site restoration costs, both as required by Statement No. 19.

The amounts reported as costs incurred in property acquisition, exploration and development activities include both capitalized costs and costs charged to expense. Exxon's 1983 costs incurred were $5,648 million, down 19 percent from 1982 mainly due to lower exploration and development costs. Exxon's 1984 costs incurred were $6,536 million, up 16 percent from 1983 mainly due to higher expenditures for exploration acreage and increased exploration drilling in the U.S.

	Total Worldwide	United States	Canada	Other Western Hemisphere	Europe	Middle East and Africa	Australia and Far East
Capitalized costs				(millions of dollars)			
As of December 31, 1983							
Property (acreage) costs							
Proved	$ 1,387	$ 1,218	$ 113	$ 6	$ 17	$ 5	$ 28
Unproved	3,827	3,602	157	7	27	16	18
Total property costs	5,214	4,820	270	13	44	21	46
Producing assets	20,818	12,422	1,170	206	5,021	67	1,932
Support facilities	932	357	106	14	135	10	310
Incomplete construction	3,809	1,702	388	3	1,162	41	513
Total capitalized costs	30,773	19,301	1,934	236	6,362	139	2,801
Accumulated depreciation, depletion, amortization and valuation provisions	10,144	7,136	622	116	1,541	40	689
Net capitalized costs	**$20,629**	**$12,165**	**$1,312**	**$120**	**$4,821**	**$ 99**	**$2,112**
Proportional interest of net capitalized costs of equity companies	$ 564	—	—	—	$ 529	—	$ 35
As of December 31, 1984							
Property (acreage) costs							
Proved	$ 1,671	$ 1,506	$ 106	$ 6	$ 14	$ 5	$ 34
Unproved	4,065	3,859	146	3	22	17	18
Total property costs	5,736	5,365	252	9	36	22	52
Producing assets	23,574	14,315	1,281	236	5,495	59	2,188
Support facilities	1,043	400	101	18	139	5	380
Incomplete construction	3,345	1,506	474	3	872	76	414
Total capitalized costs	33,698	21,586	2,108	266	6,542	162	3,034
Accumulated depreciation, depletion, amortization and valuation provisions	11,522	7,923	639	182	1,760	46	972
Net capitalized costs	**$22,176**	**$13,663**	**$1,469**	**$ 84**	**$4,782**	**$116**	**$2,062**
Proportional interest of net capitalized costs of equity companies	$ 559	—	—	—	$ 524	—	$ 35
Costs incurred in property acquisition, exploration and development activities							
During 1982							
Property acquisition costs	$ 547	$ 539	$ 6	—	—	—	$ 2
Exploration costs	1,897	932	76	$175	$ 428	$ 79	207
Development costs	4,496	2,572	179	10	1,114	14	607
Total	**$ 6,940**	**$ 4,043**	**$ 261**	**$185**	**$1,542**	**$ 93**	**$ 816**
Proportional interest of costs incurred by equity companies	$ 238	—	—	—	$ 197	—	$ 41
During 1983							
Property acquisition costs	$ 839	$ 808	$ 1	—	$ 3	$ 11	$ 16
Exploration costs	1,446	780	46	$ 50	328	25	217
Development costs	3,363	1,875	243	21	732	11	481
Total	**$ 5,648**	**$ 3,463**	**$ 290**	**$ 71**	**$1,063**	**$ 47**	**$ 714**
Proportional interest of costs incurred by equity companies	$ 193	—	—	—	$ 169	—	$ 24
During 1984							
Property acquisition costs	$ 1,332	$ 1,311	$ 4	—	—	$ 1	$ 16
Exploration costs	1,616	1,032	36	$ 31	$ 328	31	158
Development costs	3,588	1,773	304	17	1,166	29	299
Total	**$ 6,536**	**$ 4,116**	**$ 344**	**$ 48**	**$1,494**	**$ 61**	**$ 473**
Proportional interest of costs incurred by equity companies	$ 178	—	—	—	$ 163	—	$ 15

Earnings

The table below provides historical revenue, cost and earnings data regarding Exxon's oil and gas exploration and production operations during 1982, 1983 and 1984. Total earnings shown for the exploration and production activity are the same as those reflected in the primary financial statements, and as shown on pages 4 and 5. The volumes of crude oil and natural gas liquids production associated with these earnings and the net production volumes of natural gas delivered for sale by the producing function are shown on page 50. Crude oil, natural gas liquids and natural gas volumes from equity companies' production and from supplies available under long-term agreements with foreign governments are also reported on page 50.

The company believes this table (used in conjunction with the other information in this section concerning capitalized costs, costs incurred, reserves and production—all of which are presented on a geographic basis) provides interested persons with relevant information to assist in an evaluation of the company's oil and natural gas exploration and production operations and in the development of reasonable interpretations concerning the value of the oil and natural gas reserves. It is the company's opinion that this information is more meaningful for this purpose than the standardized measure of discounted future net cash flows, as prescribed by the FASB, which is contained on the following two pages.

	Total Worldwide	United States	Canada	Other Western Hemisphere	Europe	Middle East and Africa	Australia and Far East
	(millions of dollars)						
Year 1982							
Revenue	$16,037	$8,425	$825	$ 41	$3,998	$ 62	$2,686
Less costs:							
Production costs*	6,572	3,595	335	28	931	9	1,674
Exploration expense	1,712	960	64	107	355	77	149
Depreciation, depletion and amortization expense	1,934	1,276	79	9	405	19	146
	5,819	2,594	347	(103)	2,307	(43)	717
Related income tax	3,391	1,069	241	1	1,708	(2)	374
Earnings from own production	2,428	1,525	106	(104)	599	(41)	343
Proportional interest in earnings of equity companies	670	—	—	—	579	62	29
Other earnings**	333	345	4	7	(37)	(17)	31
Total earnings from exploration and production	**$ 3,431**	**$1,870**	**$110**	**$ (97)**	**$1,141**	**$ 4**	**$ 403**
Year 1983							
Revenue	$16,956	$8,136	$937	$ 72	$4,680	$ 45	$3,086
Less costs:							
Production costs*	6,027	3,299	304	24	600	9	1,791
Exploration expense	1,364	788	49	85	246	30	166
Depreciation, depletion and amortization expense	2,306	1,481	87	40	481	12	205
	7,259	2,568	497	(77)	3,353	(6)	924
Related income tax	4,136	1,078	316	—	2,262	3	477
Earnings from own production	3,123	1,490	181	(77)	1,091	(9)	447
Proportional interest in earnings of equity companies	567	—	—	—	538	8	21
Other earnings**	389	376	5	1	4	5	(2)
Total earnings from exploration and production	**$ 4,079**	**$1,866**	**$186**	**$ (76)**	**$1,633**	**$ 4**	**$ 466**
Year 1984							
Revenue	$18,236	$8,407	$930	$ 94	$5,159	$ 39	$3,607
Less costs:							
Production costs*	5,712	2,792	301	18	572	6	2,023
Exploration expense	1,328	858	33	25	245	29	138
Depreciation, depletion and amortization expense	2,704	1,762	89	54	549	10	240
	8,492	2,995	507	(3)	3,793	(6)	1,206
Related income tax	4,689	1,294	300	(5)	2,506	5	589
Earnings from own production	3,803	1,701	207	2	1,287	(11)	617
Proportional interest in earnings of equity companies	595	—	—	—	510	77	8
Other earnings**	391	311	(4)	(10)	81	12	1
Total earnings from exploration and production	**$ 4,789**	**$2,012**	**$203**	**$ (8)**	**$1,878**	**$ 78**	**$ 626**
Revenue							
Year 1982–Sales to third parties	$ 4,930	$1,510	$577	$ 41	$ 700	$ 37	$2,065
Sales to consolidated affiliates	11,107	6,915	248	—	3,298	25	621
Year 1983–Sales to third parties	5,051	1,362	611	72	785	27	2,194
Sales to consolidated affiliates	11,905	6,774	326	—	3,895	18	892
Year 1984–Sales to third parties	7,680	1,698	594	94	2,663	24	2,607
Sales to consolidated affiliates	10,556	6,709	336	—	2,496	15	1,000

* Includes taxes other than income taxes. Specifically included are U.S. "windfall profit" tax: $1,377 (1982), $853 (1983), $692 (1984) and Australian excise tax: $1,260 (1982), $1,374 (1983), $1,510 (1984).

** Includes earnings related to transportation of oil and gas, sale of supplies from other sources including long-term agreements with foreign governments, oil sands operations and technical services agreements, and reduced by minority interests.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Please see the "Discussion of Standardized Measure" on page 41.

Except as noted in the following paragraph, the standardized measure of discounted future net cash flows relating to proved oil and gas reserves is computed by applying the year-end prices of crude oil, including condensate and natural gas liquids, and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of oil and gas reserves, as shown on pages 42 and 43, less the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of both the existing economic conditions and the level of current costs.

The production costs used in calculating future net cash flows are based on the average costs for the year for consolidated affiliates. Total costs are shown on page 45. Use of year-end information would not materially alter the results. Development costs are based on existing plans for drilling, equipping and installing the actual wells and facilities, if any, required to produce the reserves held at year-end 1984. Where necessary, these existing development plans have been extrapolated, based on engineering estimates, to the end of the lease, concession, contract, etc., or to the time required to complete the recovery of the reserves, whichever is earlier. In certain instances, such as offshore platforms, existing development plans include facilities or capacity designed to produce both proved and probable reserves. These investments have been charged against proved reserves only, because the existence of the probable reserves may not be confirmed until after the investments have been made.

Related income taxes were calculated using statutory tax rates for year-end 1982, 1983 and 1984 where applicable. In some instances, particularly in foreign operations, effective income tax rates were used to estimate anticipated taxes.

The standardized measure is computed using the estimated future net cash flows and a discount factor of 10 percent per year.

	Total Worldwide	United States	Canada	Other Western Hemisphere	Europe	Middle East and Africa	Australia and Far East
				(millions of dollars)			
As of December 31, 1982							
Future cash inflows from sales of oil and gas	$224,615	$105,994	$13,821	$268	$74,648	$699	$29,185
Future production and development cash costs	101,057	57,052	6,403	192	23,312	332	13,766
Future income tax expenses	68,090	20,633	4,445	—	35,651	84	7,277
Future net cash flows	55,468	28,309	2,973	76	15,685	283	8,142
Effect of discounting net cash flows at 10%	29,565	15,724	1,967	23	7,441	127	4,283
Standardized measure of discounted future net cash flows	**$ 25,903**	**$ 12,585**	**$ 1,006**	**$ 53**	**$ 8,244**	**$156**	**$ 3,859**
As of December 31, 1983							
Future cash inflows from sales of oil and gas	$218,005	$ 97,212	$20,032	$353	$73,079	$578	$26,751
Future production and development cash costs	86,493	42,467	8,873	234	23,448	275	11,196
Future income tax expenses	70,295	24,291	6,198	—	32,628	97	7,081
Future net cash flows	61,217	30,454	4,961	119	17,003	206	8,474
Effect of discounting net cash flows at 10%	34,358	18,408	3,278	30	8,591	101	3,950
Standardized measure of discounted future net cash flows	**$ 26,859**	**$ 12,046**	**$ 1,683**	**$ 89**	**$ 8,412**	**$105**	**$ 4,524**
As of December 31, 1984							
Future cash inflows from sales of oil and gas	$218,444	$100,208	$24,099	$316	$69,539	$526	$23,756
Future production and development cash costs	84,247	39,508	10,936	194	23,009	231	10,369
Future income tax expenses	68,378	26,751	7,459	22	27,461	99	6,586
Future net cash flows	65,819	33,949	5,704	100	19,069	196	6,801
Effect of discounting net cash flows at 10%	35,870	19,661	3,420	25	9,910	82	2,772
Standardized measure of discounted future net cash flows	**$ 29,949**	**$ 14,288**	**$ 2,284**	**$ 75**	**$ 9,159**	**$114**	**$ 4,029**
Proportional interest in the standardized measure of discounted future net cash flows related to proved reserves of equity companies*							
At December 31, 1982	$ 5,040	—	—	—	$ 4,982	—	$ 58
At December 31, 1983	4,277	—	—	—	4,224	—	53
At December 31, 1984	4,361	—	—	—	4,304	—	57

*See footnote on page 43.

Change in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves — Consolidated Affiliates

In 1982, the value of the previous year's reserves increased due to development expenditures incurred during the year and to upward revisions in the estimated quantities of these reserves, particularly in the U.S., Canada, Norway, and the U.K. These improvements were more than offset by sales and transfers of oil and gas during the year and by the combined effects of flat prices and higher lifting costs, especially in the U.S. and the U.K.

For 1983, the value of the previous year's reserves increased due to development expenditures incurred during the year and to revisions in the estimated quantities of these reserves, particularly in the U.S., the U.K. and Malaysia. These improvements were essentially offset by sales of oil and gas produced during the year.

In 1984, the value of previous year's reserves also increased significantly due to revisions in the estimated quantities of these reserves, to the addition of new reserves during the year and to higher forecast production rates near-term reflecting 1984 experience.

Costs capitalized in the financial statements are expensed under the standardized measure method except for costs associated with unevaluated properties and uncompleted exploration wells which totaled $1,581 million, $1,966 million and $1,869 million at the end of 1982, 1983 and 1984, respectively. These costs are deferred until the year the evaluation is completed. Current year's development expenditures have the effect of reducing the standardized measure's development costs and are shown as an increase in present value. Current year's proceeds from producing operations recognized in the historical financial statements do not affect these results if they are identical to the assumptions used in estimating the standardized measure's values in the prior year.

Related income taxes were calculated using statutory tax rates for year-end 1982, 1983 and 1984 where applicable. In some instances, particularly in foreign operations, effective income tax rates were used to estimate anticipated taxes.

	1982	1983	1984
		(millions of dollars)	
Value of reserves added during the year, due to extensions, discoveries, other additions and improved recovery, less related costs	$ 817	$ 1,300	$ 2,463
Changes in value of previous year reserves due to:			
Sales and transfers of oil and gas produced during the year, net of production costs	(9,285)	(10,929)	(12,524)
Development costs incurred during the year	4,496	3,363	3,588
Net change in prices and production costs	(5,971)	(283)	240
Revision of previous reserves estimates	2,380	3,125	981
Accretion of discount	6,154	5,829	5,855
Other changes	(1,834)	(2,156)	3,544
Net change in income taxes	1,892	707	(1,057)
Total change in the standardized measure during the year	**$(1,351)**	**$ 956**	**$ 3,090**

See footnote on page 43.

Supplemental Information Regarding Inflation and Changing Prices

The comparability of historical financial data is reduced over time due to the effects of inflation which results in the loss of purchasing power of the reporting unit—the dollar. Since 1979, the Financial Accounting Standards Board (FASB) has required large U.S. corporations to report, on a supplemental and experimental basis, inflation-adjusted financial results. The FASB's prescribed method has proven controversial, and there is no consensus among preparers and users of financial statements regarding the best way to measure the impact of inflation. Thus, the data presented on this and the following page should not be viewed as precise measures, but indicators to be used in conjunction with other information about the company's ability to cope with inflation.

The data in Tables I and II are presented in accordance with the FASB's guidelines for current cost disclosure. The method used adjusts for the current, or specific, costs of inventory and property, plant and equipment. The current cost of inventory is the estimated current cost of purchases or production, depending on the company's normal sources of supply. For the most part, the current cost of plant and equipment represents replacement in-place and in-kind, by way of new construction, less an allowance for accumulated depreciation proportionate to that applicable to the existing assets. No consideration has been given to possible replacement of assets of a different type, at a different location or with improved operating cost efficiencies. The specific costs used, while believed reasonable, are necessarily subjective. They do not necessarily represent amounts for which the assets could be sold or costs which will be incurred, or the manner and extent in which actual replacement of assets will occur.

More specifically, land, other than oil and gas acreage, has been valued based on appraisal or estimated current market prices. Oil and gas acreage costs have been updated using the U.S. Consumer Price Index for Urban Consumers (CPI-U). Development costs of oil and gas properties were measured by use of appropriate indices or estimates of current drilling, material and equipment costs. Other plant and equipment, for the most part, was updated by use of internally developed construction cost indices. Items such as automotive equipment and office buildings were costed at current market prices.

Table I shows the results of operations in 1984 as reflected in the Consolidated Statement of Income (page 31) and as adjusted for specific cost. The largest adjustment is to depreciation, reflecting increases in specific costs of the facilities over original acquisition costs. Crude oil and product purchase costs are also increased, reflecting a higher current (vs. historic) cost of sales of quantities of LIFO inventories.

Table I also shows changes which occurred during the year as a result of inflation. The first of these is a gain resulting from the effect of the decline in the purchasing power of the dollar on the net monetary amounts owed by the company. Most of the company's current assets, except inventories, and the current liabilities, long-term debt and deferred income taxes are monetary items.

The second change represents the extent to which changes in the specific prices for inventory and property, plant and equipment during 1984 differed from the increase attributed to the effects of general inflation as measured by the U.S. CPI-U.

Also shown in Table I are the year-end amounts for inventories and property, plant and equipment, as reflected in the Consolidated Balance Sheet (page 30), and as adjusted for specific costs.

Table I – Financial results for 1984 adjusted for changing prices
(millions of dollars)

	Unadjusted	Adjusted for 1984 specific costs
Income from continuing operations		
Total revenue	$97,288	$97,288
Costs and other deductions		
Crude oil and product purchases	48,962	49,682
Depreciation and depletion	4,073	6,057
Other costs and deductions	16,846	16,846
Income, excise and other taxes	21,879	21,879
Total costs and other deductions	91,760	94,464
Income from continuing operations	$ 5,528	$ 2,824
Gain from decline in the purchasing power of net amounts owed		$ 604
Change in specific prices versus general inflation		
Inventories		58
Property, plant and equipment		(3,852)
Inventories (at year-end)	$ 4,702	11,187
Property, plant and equipment (at year-end)	42,776	65,457

Table II, below, shows a five-year summary of key financial results adjusted for changing prices.

Table II – Five-year summary of financial results adjusted for changing prices
(millions of dollars except per share amounts) (average 1984 dollars)

	1980	1981	1982	1983	1984
Income (loss) from continuing operations	$ 3,502	$ 1,731	$ (319)	$ 1,701	$ 2,824
Per share	4.02	2.00	(.36)	1.97	3.46
Gain from decline in purchasing power of net amounts owed	1,521	1,222	599	586	604
Increase/(decrease) in specific prices versus general inflation for inventories and property, plant and equipment	4,755	3,693	5,617	(2,950)	(3,794)
Foreign currency translation adjustment	(966)	(3,974)	(3,447)	(2,166)	(2,463)
Shareholders' equity at year-end	73,929	73,178	74,417	66,490	58,225

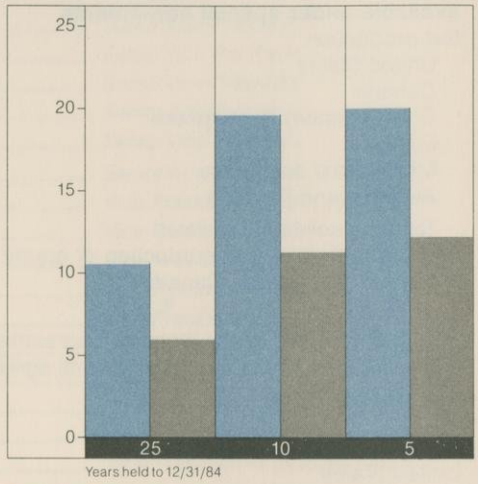
Supplementary Data adjusted for General Inflation

The charts below represent an alternative, simplified approach to displaying the effects of inflation versus the FASB requirement shown on the previous page. These charts depict five years of data for certain key financial measures. The historical information is shown by the bars, while the solid line plots trends in average 1984 dollars (adjustments made using the U.S. CPI-U).

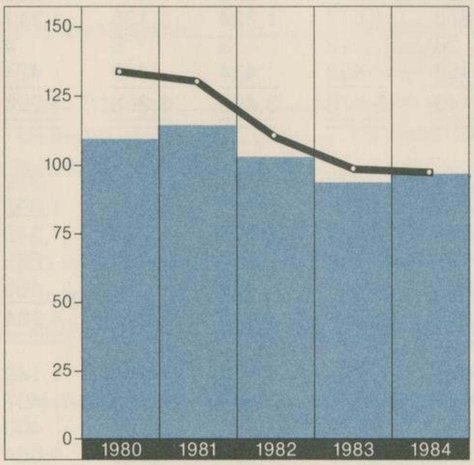
Exclusive of the effects of general price inflation, revenue has declined during the five-year period reflecting the lower prices and demand associated with slower economic growth and surplus capacity. However, the company's productivity and efficiency gains from business rationalization have largely maintained earnings and funds flow in real (inflation-adjusted) terms, while financing a high level of capital reinvestment. Dividends to shareholders have basically kept pace with general inflation throughout the five-year period. The last chart shows the movement in year-end Exxon share prices over the past five years.

The chart to the right shows the return to a shareholder from holding Exxon stock for various periods prior to year-end 1984. The before tax returns are shown on both an unadjusted basis (blue bar) and adjusted for general inflation, as measured by the U.S. CPI-U (gray bar).

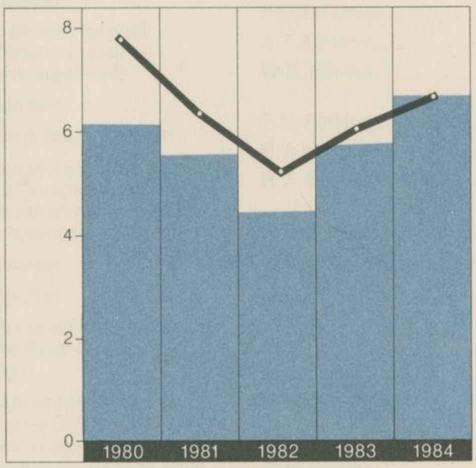
Return to a shareholder from holding Exxon stock
percent per year



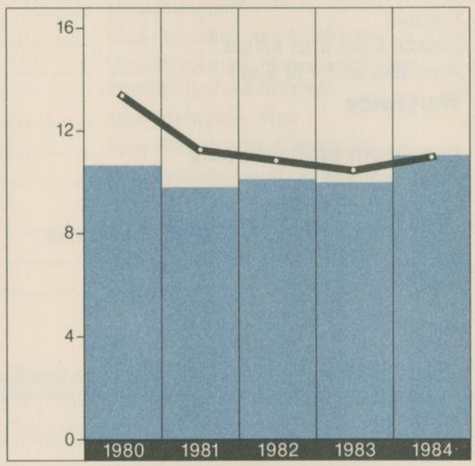
Revenue
billions of dollars



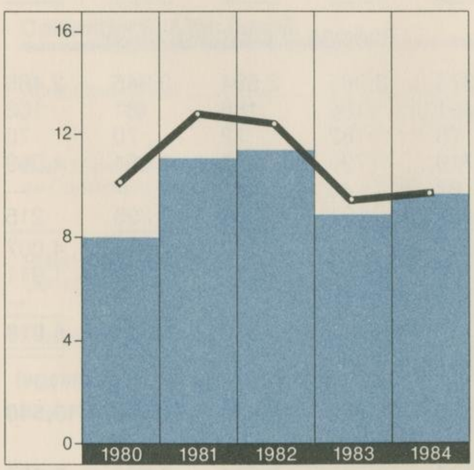
Net income
per share



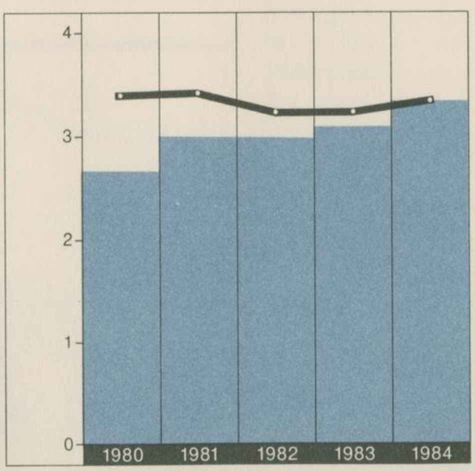
Funds from operations
billions of dollars



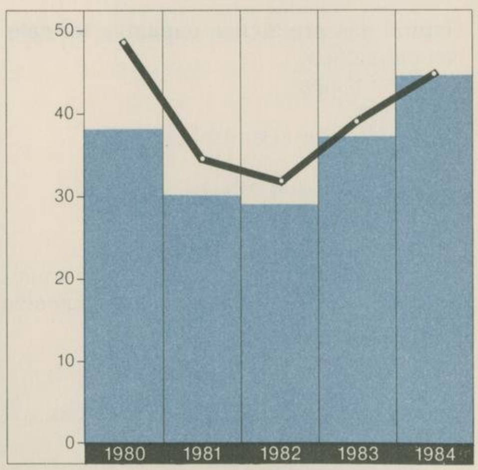
Capital and exploration expenditures
billions of dollars



Dividends to Exxon shareholders
dollars per share



Exxon share price
dollars at year-end



	1980	1981	1982	1983	1984
Average consumer price index (1967 = 100)	246.8	272.4	289.1	298.4	311.1
General inflation during year (based on average consumer price index above)	13.5%	10.4%	6.1%	3.2%	4.3%

Operating Summary

	1980	1981	1982	1983	1984
	(thousands of barrels daily)				
Net production of crude oil and natural gas liquids and petroleum supplies available under special agreements					
Net production					
United States	787	752	740	781	778
Canada	116	94	95	90	93
Other Western Hemisphere	11	11	10	14	16
Europe	155	194	289	370	412
Middle East and Africa	56	39	5	5	4
Australia and Far East	225	230	228	267	310
Total consolidated affiliates	1,350	1,320	1,367	1,527	1,613
Proportional interest in production of equity companies	351	32	33	32	21
Oil sands production – Canada	24	26	18	23	21
	1,725	1,378	1,418	1,582	1,655
Supplies available under long-term agreements with foreign governments	1,802	2,020	1,340	706	489
Other supplies available under special agreements	481	398	341	294	226
Worldwide	4,008	3,796	3,099	2,582	**2,370**
Refinery crude oil runs					
United States	1,246	1,111	989	958	1,021
Canada	447	430	366	378	365
Other Western Hemisphere	402	401	375	341	295
Europe	1,578	1,472	1,324	1,135	1,111
Middle East and Africa	23	12	8	5	4
Australia and Far East	453	452	434	449	424
Worldwide	4,149	3,878	3,496	3,266	**3,220**
Petroleum product sales					
Aviation fuels	336	323	330	316	312
Gasoline, naphthas	1,453	1,369	1,346	1,344	1,392
Home heating oils, kerosene, diesel oils	1,428	1,324	1,299	1,280	1,349
Heavy fuels	1,179	1,051	849	681	685
Specialty products	557	534	486	464	466
Total	4,953	4,601	4,310	4,085	**4,204**
United States	1,503	1,295	1,174	1,146	1,149
Canada	457	439	408	393	407
Other Western Hemisphere	472	459	453	436	400
Europe	1,902	1,807	1,704	1,566	1,684
Other Eastern Hemisphere	619	601	571	544	564
Worldwide	4,953	4,601	4,310	4,085	**4,204**
Natural gas production available for sale	(millions of cubic feet daily)				
Net production					
United States	3,373	3,065	2,594	2,345	2,485
Canada	191	186	186	181	168
Other Western Hemisphere	78	82	72	70	70
Europe	719	799	773	851	1,069
Middle East and Africa	87	46	—	—	—
Australia and Far East	189	251	264	225	215
Total consolidated affiliates	4,637	4,429	3,889	3,672	4,007
Proportional interest in production of equity companies	2,396	2,191	1,860	1,956	1,911
Supplies available under long-term agreements with foreign governments	104	107	—	—	—
Worldwide	7,137	6,727	5,749	5,628	**5,918**
	(thousands of deadweight tons, daily average)				
Tanker capacity, owned and chartered	22,570	21,880	18,930	15,820	**13,540**
	(thousands of barrels daily)				
Pipeline throughput	3,297	2,740	2,624	2,600	**2,694**

Operating statistics other than pipeline throughput include 100 percent of operations of majority-owned affiliates; for other companies, gas and crude production include Exxon's ownership percentage, and crude runs include quantities processed for Exxon.

Pipeline throughput represents quantities delivered for Exxon by all companies in which a stock interest is held. Net production excludes royalties and quantities due others when produced, whether payment is made in kind or cash.

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APPENDIX 1.1A

SUMMARY OF DOCUMENT SUBMITTALS TO DNR

Resources Submitted to the Wisconsin Department of Natural Resources

Aug 05, 1977	-	Dames and Moore Personnel Biographical Data
	-	Dames and Moore Field Notes
	-	Air Data Report
	-	Dames and Moore Air Quality Testing Procedures
Nov 04, 1977	-	Suggested Air Quality Monitoring Locations
Nov 21, 1977	-	Technical Project Plan for Environmental Studies for the Crandon Project Dated November 14, 1977
Feb 07, 1977	-	Environmental Criteria and Metallurgies on Tailings Disposal Site Selection
Mar 20, 1977	-	Interim Report on Phytoplankton and Zooplankton
May 05, 1977	-	Surface Water Quality Data Sheets for Stations E, G-1, H, M-2, and S
Jun 16, 1978	-	Development of Idaho Guidelines for Mine and Mill Waste Disposal Through 208 Planning--A Case Study
Aug 09, 1978	-	Inventory of Environmental Data Collected Prior to July 1, 1978
Sep 18, 1978	-	Infrared Aerial Photos Covering Primary Area of Environmental Investigation
Dec 18, 1978	-	"Master Schedule" for Exxon's Crandon Project
Jan 22, 1979	-	Site Area Selection for Concentrator Facilities
	-	Scope of Work: Lakefield Research of Canada--For Various Metallurgical Testing and Development Work
	-	Golder Associates Inc.--For Preliminary Engineering Tailings Disposal
	-	Ralph M. Parsons Co.--Phase II Engineering Surface Facilities
	-	Kilbourn Engineering Ltd.--Phase I, Water Management Study
Feb 28, 1979	-	Site Identification for Disposal of Tailings, Phase I
	-	Concentrator Siting Study Report
	-	Scope of Work: For Environmental Related Contracts

Resources Submitted to the Wisconsin Department of Natural Resources

Mar 15, 1979	-	Results of Split Ground Samples Taken at Wells DMB 1A 4-78 and 18
Mar 23, 1979	-	List of Borings Re: Water Levels and/or Quality
Apr 09, 1979	-	1' = 1000' Scale Map of DMA DMB Series of Bore Holes in the Ore Body
May 01, 1979	-	Siting Report for Disposal of Tailings
May 07, 1979	-	Letter to Roy Tull Re: Crandon Ore Body and Processing Methods Dated March 16, 1979
May 14, 1979	-	Environmental Movie
Jun 17, 1979	-	Draft Technical Plan
Jun 19, 1979	-	Analytical Data for Split Ground Water
Jun 28, 1979	-	Mine and Concentrator Waste Characterization Studies for the Crandon Project
Jul 09, 1979	-	Orthophoto-Topographic Maps and Aerial Color Infrared Photographs of the Crandon Project Region
Jul 12, 1979	-	Data on Optical Characterization Airborne Particulates
Jul 17, 1979	-	Aerial Photo Legend Maps of Crandon Project Region
	-	Orthophoto-Topographic Maps and Aerial Photo Legend Maps of the Crandon Project Region
Jul 20, 1979	-	Preliminary Common Name Species Dames and Moore Lists from Environmental Baseline Data for the Crandon Project Study Area
Aug 14, 1979	-	Preliminary Scientific Name Species Dames and Moore Lists from Environmental Baseline Data for the Crandon Project Study Area
Aug 31, 1979	-	Biological Leaching of Sulfide Ores
	-	Practical Aspects of Biological Leaching Studies
	-	Prediction of Acid Generation Potential
	-	British Columbia Research Brochure
Sep 06, 1979	-	Housing Study Outlines

Resources Submitted to the Wisconsin Department of Natural Resources

Nov 07, 1979	-	Archaeological Research in the Potential Exxon Minerals Company, U.S.A. Mining Area, Forest and Langlade Counties Wisconsin
	-	Addendum to Dames and Moore Technical Project Work Plan
	-	Scope of Work - Phase II Water Management Study (Ch2M Hill Contract)
Jan 17, 1980	-	Ortho-Topographic (OTM) Maps of Crane, Lily, Jungle and Bradley Lakes
	-	Entire Exxon OTM Sepias
	-	Wetlands Map (1' = 1000')
	-	Wetlands Map (1' = 400')
Jun 04, 1980	-	Phase I Pilot Plant Program--Crandon Project
Aug 07, 1980	-	Definition of the Local Study Area
Oct 17, 1980	-	Study Plan
Oct 28, 1980	-	Survey Research Methodology
Nov 06, 1980	-	Volume I: Preliminary Project Description
Nov 12, 1980	-	Sociocultural Analysis Methodology
Nov 14, 1980	-	Definition of the Local Study Area - Revised
Jan 01, 1981	-	Native American Methodology
Jan 30, 1981	-	Terrestrial Ecology Baseline and Methods Sections of the Environmental Impact Report
	-	A Survey of The Distribution and Abundance of Spotted Salamanders in a Portion of Northern Wisconsin
Mar 05, 1981	-	Location Map Drawing No. C-PE-0030 - Location of Eleven Soil Borings. Also Included is a Written Description of Work for Boring and Soil Sampling Program
Apr 03, 1981	-	Fiscal Analysis Methodology
Apr 09, 1981	-	Wetlands Assessment, Technical Work Plan for Crandon Project
	-	Inland Ecology Technical Procedures Manual

Resources Submitted to the Wisconsin Department of Natural Resources

	-	Normandeau Associates, Inc., Quality Assurance Manual
Apr 10, 1981	-	Water Management Program, Exxon Minerals Company, Crandon Project
Apr 16, 1981	-	Geology Baseline and Methods Sections of the Environmental Impact Report
Apr 28, 1981	-	Waste Management Program, Exxon Minerals Company
Apr 30, 1981	-	Noise Baseline and Methods Sections of the Environmental Impact Report
Apr 30, 1981	-	Terrestrial Ecology Report
Aug 18, 1981	-	Radiological Testing Program
Aug 31, 1981	-	Fiscal Analysis Methodology (replaced 3/81 version)
Sep 04, 1981	-	Volume II - Study Work, Project Description
Sep 08, 1981	-	Technical Work Plan For Archaeologial Study
Sep 10, 1981	-	Demographic Analysis Methodology
Oct 01, 1981	-	Options for Discharge of Treated Water - Crandon Project, by L. N. Blair
Oct 27, 1981	-	Waste Characterization Testing By B.C. Research, Chain-of-Custody, and Laboratory Procedures
	-	Contract Work Description for Contract for Laboratory Services w/CSMRI for Waste Characterization Studies on Typical Crandon Concentrator Tailings.
	-	Contract Work Description for Contract w/B.C. Research, Vancouver Canada for Waste Characterization Studies for Typical Waste Rocks from the Crandon Mineral Deposit.
	-	Letter dated July 2, 1981 containing chemical analyses for EP toxicity on six tailing samples from Lakefield Pilot Plant.
	-	Letter dated July 14, 1981 containing results of EP txicity tests performed on samples of Crandon footwall rocks.
Nov 05, 1981	-	Public Facilities and Services Methodology (RPC)
Nov 05, 1981	-	Analogous Areas Methodology and Report on Case Selection (RPC)

Resources Submitted to the Wisconsin Department of Natural Resources

Nov 18, 1981	-	Phase II Water Management Study, Interim Report - Volumes I and II (CH2M Hill)
Nov 18, 1981	-	Preliminary Engineering Surface Facilities, Crandon Project - Volumes II and IV (R.M. Parsons)
Nov 18, 1981	-	Geotechnical Review, Volumes I, II and III; Pump Test and Analyses; Groundwater Potentiometric Contours (Golder Associates)
Nov 19, 1981	-	Report on Current Conditions (RPC)
Jan 08, 1982	-	Ground Water Baseline and Methodology Report
Jan 11, 1982	-	Groundwater Potentiometric Countours Maps
Feb 05, 1982	-	Ground Water Study & Study Methods Report
	-	Fish Data From Swamp Creek
	-	Minutes of Exxon/DNR Meetings January 6 & 7
Feb 12, 1982	-	Surface Water Baseline & Methodology Paper
Feb 16, 1982	-	Series of Charts and Maps Pertaining to Proposed Alternate Routes for Tailings Transport and Reclaim Water.
Feb 18, 1982	-	Wolf River Data Between October 1977 - October 1978, prepared by Dames & Moore
Feb 23, 1982	-	Preliminary Mining Plan Outline re: NR 132.07
Mar 08, 1982	-	"Golder Comparison of site Areas 30, 31, 40, and 41", Golder Associates, February, 1982
	-	"Engineering Siting Report - Tailings Disposal Sites - Phase I, Crandon Project", Dames and Moore, February, 1978
	-	"General Properties of Common Liners, Crandon Project, Waste Disposal System, Project Report 6.1", Golder Associates, December 1981
	-	"Evaluation of Prospective Common Liners, Crandon Project, Waste Disposal System, Project Report 6.2,", Golder Associates, December, 1981
	-	"Characterization of Crandon Mill Tailings", Colorado School of Mines Research Institute, January, 1982

Resources Submitted to the Wisconsin Department of Natural Resources

Mar 09, 1982 - Summary Description Of The Sequence of Events Re Siting Of A Rail Spur and Road Access Corridor For The Crandon Project

Mar 16, 1982 - "Pyrite Processing Summary", Davy McKee, June 1981

Mar 17, 1982 - Forest Inventory Scope of Work

Mar 26, 1982 - EIR Outline, Crandon Project

- Aquatic Monitoring Scope of Work, Crandon Project

Apr 01, 1982 - Aquatic Ecology Report (including Appendices)

Apr 14, 1982 - "Archaeological Inventory and Evaluation at Exxon Minerals Company, Crandon Project Site, in Forest and Langlade Counties, Wisconsin," GLARC

- "Evaluation of Buildings in the Crandon Project Area, Forest County, Wisconsin", MacDonald & Mack Partnership

May 24, 1982 - Draft "Tailings Pond Reclamation Cover" - Golder

May 28, 1982 - Draft Mining Plan Outline - Exxon

- Draft Reclamation Plan Outline - Exxon

- Draft Water Treatment Alternatives

- Draft Tailings Pond Reclamation Cover

Jun 08, 1982 - Study Plan for the Aquatic Monitoring Program on Swamp Creek

Jun 09, 1982 - Draft Outline Risk Assessment Section of Mine Permit Application

Jun 16, 1982 - Addendum to the Archaeological Inventory and Evaluation Report GLARC

Jun 18, 1982 - Review of the Potential Alternative Mine Waste Disposal Areas

- Hydrologic Impact Assessment Scope of Work

Jul 19, 1982 - Revised Draft - Risk Assessment Development Outline, Crandon Project

Aug 12, 1982 - Technical Work Plan, Dames and Moore - Air Permit Submittal

Aug 16, 1982 - Geotechnical Review, Crandon Project Waste disposal System, Project Report 2, Volumes 1-3, Golder Associates

Aug 16, 1982 (continued)	-	Pump Test and Analyses, Crandon Project Waste Disposal System, Project Report 4, Golder Associates
	-	Ground Water Potentiometric Contours, Crandon Project Waste Disposal System, Project Report 7, Golder Associates
Aug 17, 1982	-	Wetlands Assessment Report (consists of four documents: Wetlands Assessment Report; Wetlands Assessment Appendices; Wetlands Assessment Maps; Wetlands Assessment Inventory Reports) IEP
Aug 20, 1982	-	Surface Water Study and Study Methods, with Appendices, Dames and Moore
	-	Ground Water Study and Study Methods, Dames and Moore
	-	Geology Study and Study Methods, Dames and Moore (2)
Aug 23, 1982	-	Visual Impact Analysis - Scope of Work
Dec 22, 1982	-	Crandon Project Environmental Impact Report (EIR)
Feb 01, 1983	-	Parametric Seepage Rate Estimated Crandon Project Waste Disposal System, Project Report 3.1, Golder Assoc.
	-	Underdrain Review, Crandon Project Waste Disposal System Project Report 3.2, Golder Assoc.
Feb 01, 1983	-	Laboratory Testing Programs, Crandon Project Waste Disposal System, Project Report 5, Golder Assoc.
	-	Tailings Pond Reclamation Cover, Crandon Project Waste Disposal System, Project Report 10, Golder Assoc.
	-	Addendum No. 1, Geotechnical Review, Crandon Project Waste Disposal System, Golder Assoc.
	-	Tailings Storage Facility Report On Preliminary Design - Volume 1, Knight & Piesold
	-	Tailings Storage Facility Report on Preliminary Design - Volume 2, Knight & Piesold
	-	Soil Attenuation Study - Volume 1, D'Appolonia Consulting Engineers
	-	Soil Attenuation Study - Volume 2, D'Appolonia Consulting Engineers

Resources Submitted to the Wisconsin Department of Natural Resources

Feb 01, 1983 (continued)	-	Soil Boring and Laboratory Test Results of Little Sand Lake Drilling Project, Soil Testing Services of Wisconsin
	-	Waste Disposal Facility Reclamation Cap, Owen Ayre & Associates
	-	EIR Chapter 1, Construction of Waste Disposal Facilities, INDECO
	-	Forest Inventory, Timber Appraisal, and Forest Management Recommendations on 3,474 Acres of the Crandon Mine Project, E. F. Steigerwaldt & Sons
Feb 07, 1983	-	Letter, Robert Russell to John Schallock, re: Exxon position on management of timber on Exxon land and recreational use of Exxon land, dated December 16, 1980
	-	Letter, Lou Pygin to Curt Fowler, re: Noise Contours and Backup Data for Construction Noise Analyses, dated September 3, 1982
	-	Letter, Lawrence Tisdel to James Wennen, re: set of 3 plots and 1 table providing data obtained from alkaline leaching studies on Samples 2, 3, and 5, dated September 18, 1981
	-	Report, Miscellaneous Details and Analyses, Crandon Project Waste Disposal System Project Report 11, Golder Associates
	-	Report, Excess Water Discharge, Crandon Project Waste Disposal System, Golder Associates
	-	Report, A Preliminary Study of Requirements for Plant Growth on Soils from the Crandon Project Area, Mine Waste Reclamation Ltd.
	-	Report, Assessment of the Acid-Producing Characteristics of Crandon Hanging Wall Material of Varying Sulfur Content, Division of Applied Biology, B.C. Research
	-	Report, Waste Characterization Studies of Typical Waste Rocks from the Crandon Mineral Deposit, Project Report No. 2, Division of Extractive Metallurgy, B.C. Research
	-	Report, Study on Characterization of Crandon Mill Tailings, Colorado School of Mines Research Institute
	-	Report, Tailings Storage Facility Report on Conceptual Design, Knight and Piesold Ltd.

Resources Submitted to the Wisconsin Department of Natural Resources

Feb 07, 1983 (continued)	-	Report, Mine Site Access Road, Route Location Study, Inman-Folz & Associates
	-	Report, Preliminary Engineering, Mine/Mill Access Road, Volume I, Foth & Van Dyke
	-	Report, Preliminary Engineering, Mine/Mill Access Road, Volume II, Foth & Van Dyke
	-	Report, Preliminary Engineering, Mine/Mill Railroad Spur, Volume I, Foth & Van Dyke
	-	Report, Preliminary Engineering, Mine/Mill Railroad Spur, Volume II, Foth & Van Dyke
Feb 28, 1983	-	Report, Phase III Water Managemnet Study, CH2M Hill Central, Inc.
	-	Report, Ground Water Inflow Model for the Proposed Crandon Mine, Thomas A. Prickett & Associates
	-	Report, System Development, Crandon Project, Waste Disposal System, Project Report 8
	-	Report, Geohydrologic Characterization, Crandon Project
	-	Report, Ground Water Impact Screening Model, Cradon Project Waste Disposal System, Project Report 9
Feb 17, 1983	-	Scope of Work for Aquatic Monitoring Program in Swamp Creek
Feb 24, 1983	-	Golder Report No. 8 "Systems Development" (Note: Report includes Golder Reports "Geohydrologic Characterization" and "Groundwater Impact Screening Model"
Apr 14, 1983	-	Three applications for State of Wisconsin Chapter 30/31 - Construction permit applications for structures to be installed with the proposed access road and railroad spur.
Apr 26, 1983	-	Plan sheet showing model elements with node and element numbering and a coordinate grid superimposed
	-	Printed listing for all node numbers withoordinates for the model grid and equivalent Wisconsin State plan grid coordinates
	-	Listing of GEOFLOW program code

	-	Set of printout (Files 1-4) of model runs for cases studied and presented in Appendix 4.1A.
	-	GEOFLOW USERS Manuals
	-	Full size reproducibles of boring location maps Drawings Nos. 050-1081333 and 050-1-81334
	-	Full size reproducibles of ground water potentiometric contours Drawing Nos. 050-1-81118 and 050-1-81121
May 2, 1983	-	February Benthos Data - Swamp Creek
May 8, 1983	-	Water Quality Monitoring Swamp Creek - April 1982 - March 1983
May 9, 1983	-	Revised copies of May 14 submissions (backside of one page not copied)
Jul 6, 1983	-	Water Chemistry Data, March-May 1983, Swamp Creek
Jul 11, 1983	-	April 1983, Fish Data, Swamp Creek
Jul 15, 1983	-	Geophysical Logging and Interpretation Report, CDM
Jul 11, 1983	-	Responses to DNR letter of November 23, 1982 regarding Exxon's "Siting Report - Review of Potential Alternative Mine Waste Disposal Areas."
Jul 15, 1983	-	Crandon Project Mine Waste Disposal Facility Feasibility Incompleteness Response with 21 Attachments: + B. C. Research 1982 - Final Report + Exxon 1979a - Clay Deposits; Supplemental Report + Exxon 1979b - Asbestiform Notes + Exxon 1979c - Tailings Seepage Quality + Davy McKee 1981a - Pyrite Processing Economics + Locations of the STS Test Pits + "Construction Aspects" Report, March 1983 + INDECO Report, "Construction of Waste Disposal Facilities", September 1982 + Report "Operating Aspects and Contingency Plans - Seepage Control System" + "Miscellaneous Details and Analyses" Report, September 1982. (Report provided to DNR Feb, 1983) + Maps depicting the routes from the Woodlawn Siding area & to the MWDF and from the mine/mill area to the MWDF. + PSI Report, August 1982, Re: Studies on the Tailings and Water Transport Lines

+ 24" x 36" Drawings Showing a Construction and Material thru Volume Schedule and the Phase by Phase Development of the MWDF as presented in the INDECO Report, "Construction of Waste Disposal Facilities, September 1982
+ Report "Tailings Surface Dusting from Wind Erosion"

Aug 05, 1983 - Water and Sediment Chemistry Data, May-July 1983, Swamp Creek

Aug 15, 1983 - Addendum to Archaeological Inventory and Evaluation Report, GLARC

Sep 13, 1983 - Application for State of Wisconsin Chapter 30/31 Construction Permit, Proposed Water Discharge Structure on Swamp Creek Downstream from County Trunk Highway M

Sep 14, 1983 - Water and Sediment Chemistry and Hydrology in Swamp Creek for the Crandon Project, July 1983, Ecological Analysts

Aquatic Biology of Swamp Creek for the Crandon Project, August 1983, Ecological Analysts

Sep 15, 1983 - Application for Wisconsin Pollutant Discharge Elimination System Permit (WPDES) (Discharge Serial No. 001)

Sep 16, 1983 - Responses to DNR Comments on Chapters 2 and 3 and the Appendices of the Crandon Project EIR

Sep 23, 1983 - Additional Copies of Addendum to Archaeological Inventory and Evaluation Report, GLARC

\- Application for Wisconsin Pollutant Discharge Elimination System Permit for Erosion Control Facilities (WPDES)

Sep 27, 1983 - Inman-Foltz Work Results Re: Resurvey of all Site Piezometers

Sep 30, 1983 - Response to DNR Review Comments Re: Joint State/Federal Application for Water Regulatory Permits and Approvals for Access Road and Railroad Spur

Oct 03, 1983 - Responses to DNR Comments on Chapter 1 of the Crandon Project EIR

Oct 06, 1983 - Additional Copies of Chapter 1 Responses to DNR Comments

Oct 14, 1983 - High Capacity Well Permit Application

Oct 14, 1983 (continued) - Additional 20 Copies of: Ecological Analysts' report "Final Report, Water and Sediment Chemistry and Hydrology in Swamp Creek for the Crandon Project, July 1983; and Aquatic Biology of Swamp Creek for the Crandon Project, August 1983."

Oct 17, 1983 - Supplemental Wetlands Assessment Report, August 1983 (updated), Interdisciplinary Environmental Planning, Inc.

Oct 21, 1983 - Supergene Weathering at the Crandon Deposit, Exxon Report.

Oct 26, 1983 - Analytical Results from the Aquatic Monitoring Program in Swamp Creek, from July - September 1983

Oct 27, 1983 - Request for Additional Copies of Crandon Project Mine Waste Disposal Facility Feasibility Incompleteness Response with 21 Attachments:

+ B. C. Research 1982 - Final Report
+ Exxon 1979a - Clay Deposits; Supplemental Report
+ Exxon 1979b - Asbestiform Notes
+ Exxon 1979c - Tailings Seepage Quality
+ Davy McKee 1981a - Pyrite Processing Economics
+ Locations of the STS Test Pits
+ "Construction Aspects" Report, March 1983
+ INDECO Report, "Construction of Waste Disposal Facilities", September 1982
+ Report "Operating Aspects and Contingency Plans - Seepage Control System"
+ "Miscellaneous Details and Analyses" Report, September 1982. (Report provided to DNR Feb, 1983)
+ Maps depicting the routes from the Woodlawn Siding area & to the MWDF and from the mine/mill area to the MWDF.
+ PSI Report, August 1982, re Studies on the Tailings and Water Transport Lines
+ 24" x 36" Drawings Showing a Construction and Material thru Volume Schedule and the Phase by Phase Development of 20) the MWDF as presented in the INDECO Report, "Construction of Waste Disposal Facilities, September 1982
+ Report "Tailings Surface Dusting from Wind Erosion"

Nov 03, 1983 - Crandon Project Mine Water Control Plan Alternative Evaluation and Preliminary Engineering for Exxon Minerals Company, June 1982, Klohn Leonoff Consulting Engineers

Nov 07, 1983 - Socioeconomic Study for the Crandon Project

Resources Submitted to the Wisconsin Department of Natural Resources

Nov 09, 1983 - Parametric Seepage Rate Estimates, Golder Assoc., March 1982

- Underdrain Review, Golder Assoc., March 1982
- Water Disposal Facility Reclamation Cap, Owen Ayres, Nov. 1982
- Archeological Inventory and Evaluation, Addendum, GLARC June 1983
- Hydrological Balance for Selected Wetlands, IEP, Dec. 1982
- Preliminary Study of Requirements for Plant Growth on Soils, Mine Water Reclamation, Ltd., June 1982
- Mine Site Access Road Route Location Study, Inman-Foltz
- Evaluation of Surface Effects Crandon Project, J.D. Smith
- Radiological Testing Program, Hazleton
- Excess Water Discharge, Golder

Nov 09, 1983 - Forecast of Future Conditions, RPC, 1983

Nov 09, 1983 - Definition of Local Study Area, RPC,

- Demographic Analysis Methodology, RPC
- Housing and Land Use Analysis Methodology, RPC
- Fiscal Analysis Methodology, RPC
- Native American Communities Analysis Methodology, RPC
- Public Facilities & Services Analysis Methodology, RPC

Nov 14, 1983 - Responses to DNR Comments on the Mining Permit Application

- RPC Responses to SIR Review Comments on the Study Plan; Definition of the Local Study Area; Demographic Analysis Methodology; Public Facilities and Services Analysis; Sociocultural Analysis Methodology; and Fiscal Analysis Methodology
- Responses to DNR Comments on Chapter 1 of the EIR

Nov 15, 1983 - Laboratory Testing Programs, Crandon Project Waste Disposal System, Golder Assoc. May, 1982

- Logistic Report on a Refraction Seismic Survey, Geoterrex, Ltd., April 1980

Nov 15, 1983 (continued)	-	An Interpretation Report for a Gravity and Vertical Electrical Sounding Survey, Geoterrex, Ltd., November 1981
	-	Forest Inventory, Timber Appraisal, and Forest management Recommendations, Steigerwaldt & Sons, July 1982
	-	Characterization of Crandon Mill Tailings, Colorado School of Mines, October 1982
	-	Miscellaneous Details and Analyses Crandon Project Waste Disposal System, Golder Assoc., September 1982,
	-	Archaeological Inventory & Evaluation, GLARC
Nov 16, 1983	-	Phase III Water Management Study, CH2M Hill, Volumes I, II and III
	-	Davy McKee - Pyrite Reports: + Pyrite Processing Study - Phase I, Marketing, Transportation, Process Technology, Nov. 1979 (25) + Pyrite Processing Study - Summary June 1981 (20) + Pyrite Processing Study - Appendix, March 1980 (20) + Pyrite Processing Market Studies - Final Report, Nov. 1979,
Nov. 28, 1983	-	Geohydrologic Characterization, Golder Assoc., 1982
	-	Ground Water Potentiometric Contours, Golder Assoc.
	-	Ground Water Screening Model, Golder Assoc. 1982
	-	Evaluation of Prospective Common Liners, Golder Assoc.
	-	Tailings Pond Reclamation Cover, Golder Assoc.
	-	Tailings Storage Facility Report on Preliminary Design, Knight & Piesold
	-	Ground Water Inflow Model for Crandon Mine, Prickett & Assoc., 1982
	-	Supplemental Wetlands Assessment Report, Normandeau & IEP, Inc.
Dec 06, 1983	-	Geotechnical Review, Vol. 1, 2, 3, Golder Assoc. 1982
	-	Pump Test and Analysis, Golder Assoc., 1982
	-	Addendum No. 1, Geotechnical Review, Golder Assoc., 1982
	-	Systems Development Report, Golder Assoc. 1982
	-	Wetlands Assessment Report, Normandeau & IEP

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Dec 06, 1983 (continued)	-	Soil Attenuation Study, Vol. I, II, D'Appolonia, 1982
	-	Mine/Mill Railroad Spur, Vol. I, II, Foth & Van Dyke, 1982a
	-	Mine/Mill Access Road, Vol. I, II, Foth & Van Dyke, 1982b
	-	Construction of Waste Disposal Facilities, INDECO, 1982
	-	Tailings Ponds Water Clarification Pools, EMC, 1982
	-	Results of Geologic Geotechnical and Hydrologic Investigations of a Portion of the Proposed Exploration Ramp, Dames & Moore, 1977
	-	Investigations of Feasibility of Dewatering and Other Alternatives for Open Pit Mine Options, Dames & Moore, 1977
	-	Results of Permeability Tests and Analyses of Water Samples from Deep Exploration Holes, Dames & Moore, 1978
Dec 08, 1983	-	Mine Hydrology Test Data Analysis, Final Report, Camp Dresser & McKee, Inc., May 1982,
Jan 10, 1984	-	Maps: Land Ownership Map, EMC Skunk Lake Drillhole Map Duck Lake Drillhole Map Deep Hole Drillhole Map Oak Lake Drillhole Map
Jan 13, 1984	-	GEOFLOW User's Manual, D'Appolonia, May 1983
	-	Crandon Project Mine Water Control Plan Alternative Evaluation and Preliminary Engineering, Klohn Leonoff, June 1982
	-	Ground Water Flow Model for Exxon Ore Body Near Crandon, Prickett, Jan 1982
	-	Logistic Report on a Refraction Seismic Survey, Geoterrex Ltd., April 1980,
	-	The Gravity and Vertical Electrical Sounding Survey Conducted on Behalf of EMC at Swamp Creek, Geoterrex, Ltd., Nov. 1981
Jan 18, 1984	-	Figures Designating Aquatic Ecology Sampling Locations and Aquatic Macrophyte Distribution, EMC
Feb 02, 1984	-	Forecast of Future Conditions, RPC, Inc.

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Feb 07, 1984	-	Noise Portion of the EIR
Feb 15, 1984	-	Survey Results, Socioeconomic Assessment, Jul 1981, RPC: + Vol. 1, Technical Discussion, Feb. 1981, RPC + Vol. 2, Permanent Residents Survey Data, Feb. 1982 + VOl. 3a, 3b, 3c, Seasonal Residents Survey Data, Feb. 1981 + Vol. 4, Tourists Survey Data, Feb. 1981
Feb 24, 1984	-	Results of Duck Lake Water Sampling, Northern Lake Service, Inc., Feb. 17, 1984
Mar 01, 1984	-	Responses to DNR comments on the EIR and Wetlands Assessment Reports (DNR Letter Dated December 29, 1983)
Mar 08, 1984	-	Noise Impact Assessment Report, Dames and Moore, 1984
Mar 22, 1984	-	The Validation and Improvement of Socioeconomic Forecasting Methodologies, Volumes I and II Jobs and Skills Related to Eventual Exxon Positions
Apr 20, 1984	-	"Transportation Rate Estimates" Davy McKee (Jones, Bardelmeir & Co., LTd.) Sept. 1979
Apr 26, 1984	-	Scope of Work, 1984 Aquatic Monitoring Program in Swamp Creek
May 08, 1984	-	Chemistry and Hydrology in Swamp Creek, 1983, Ecological Analysts, Inc., 1983 Aquatic Biology of Swamp Creek for the Crandon Project, January-December 1983, Ecological Anaysts, Inc., 1983
May 29, 1984	-	Bedrock Permeability Report, Crandon Project, Roger Rowe, May 1984
Jun 14, 1984	-	"Tree Rooting Potential on the Mine Waste Disposal Facility", Dr. David Grigal, Forestry/Soils Consultant to Ayres Associates, 1984
Jun 20, 1984	-	Ground Water Computer Modeling Data Tapes - 3 (1 each)
Jul 03, 1984	-	Thermo-Dynamic Data" from D'Appolonia Consulting Engineers, Inc.

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Jul 03, 1984 (continued)	-	Letter dated December 9, 1982, from John L. Shafer, of Exxon Minerals Company, to John C. Wright, D'Appolonia Consulting Engineers, Inc.
	-	"Handbook of Thermo-Chemical Data for Compounds and Aqueous Species"
	-	"Critical Stability Constants (Volume 4: Inorganic Complexes" (Paper)
Jul 23, 1984	-	Conceptual Plan - Water Management/Treatment and Discharge, Crandon Project - 10 Blueprints
	-	Hydrogeologic Study Update for the Crandon Project, Exxon Minerals Company, Volume I and II, June, 1984; STS Consultants Ltd.
Jul 23, 1984	-	EIR, Chapter 1, Project Description, Revised
		EIR, Chapter 3, Alternatives to the Proposed Action
	-	Hydrogeologic Study Update for the Crandon Project, Volume I and II, June 1984; STS Consultants Ltd.
Jul 31, 1984	-	Responses to DNR Comments on the Mining Permit Application May 25, 1984 Letter
Aug 03, 1984	-	Testing of Conventional, Pyrite Concentrate and Pyrite Slimes Backfill Materials -- Crandon Project and Appendix A, B-1, B-2, C, D, and E; September 1981; J. D. Smith Engineering Associates Limited.
	-	Rock Mechanics Testing and Engineering of large Diameter Core; September 1981; J. D. Smith Engineering Associates Limited.
Aug 09, 1984	-	Errata for August 1983 Supplemental Wetlands Assessment Report, Crandon Project; IEP, Inc.; August 1984
Aug 31, 1984	-	Revised EIR Chapter 2.0 (Sections 2.1, 2.2, 2.3, 2.4, 2.5, 2.6, 2.7, 2.8 and 2.9)
Sep 12, 1984	-	Bentonite-Amended Soil Liner Usage in Solid Waste Disposal Facilities: Case Histories; Black and Veatch, June 1984

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Sep 14, 1984	-	Bentonite-Amended Soil Liner . . . (Same as 9/12/84)
Sep 19, 1984	-	EIR, Chapter 1, Revised
	-	EIR, Chapter 2, Revised
	-	EIR, Chapter 3, Revised
	-	Reclamation Cap Design and Water Balance Analysis, Ayres Associates, September 1984
	-	Laboratory Testing Program Involving Soil/Bentonite Liner Study for Crandon Mine Waste Disposal Facility, STS Consultants, Ltd., September 1984
	-	Private Water Well Survey, 54 EMC Well Information Forms, Zone 1, (2); 111 EMC Well Information Forms, Zone II and III,
Sep 24, 1984	-	Hydraulic Relationship Between Site Area Lakes and the Main Ground Water Aquifer, Crandon Project, Forest County, Wisconsin; Dames & Moore
	-	Laboratory Testing Program Involving Soil/Bentonite Liner Study for Crandon Mine Waste Disposal Facility, STS Consultants, Ltd.,
	-	Documentation of Design and Construction of Bentonite Modified Soil Underseals for the Key Lake Project, Saskatchewan; Knight and Piesold Ltd., September 1984
Sep 28, 1984	-	Water Treatment Facility Engineering Report; CH2M Hill, September 1984
Oct 16, 1984	-	EIR Appendix 4.1A - Revised, Exxon Minerals Company,
Oct 17, 1984 & Nov 02, 1984 & Nov 15, 1984	-	NR 182.08 Feasibility Report for the Mine Waste Disposal Facility (Revised)
Oct 19, 84	-	Bentonite-Amended Soil liner Usage in Solid Waste Disposal Facilities: Case Histories; Black & Veatch with reports and papers as attachment
Oct 19, 84	-	Water Balance Analyses for Wetlands in the Mine Waste Disposal Facility Area; Ayres Associates

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Oct 31, 1984	-	Water Treatment Testing - Crandon Project; September 1984; by John L. Shafer, Exxon Minerals Company, Minerals Processing Research Division
Oct 31, 1984	-	Response to DNR Comments dated July 9, 1984 Re: the Noise Permit Application
Nov 01, 1984 & Nov 05, 1984	-	Predictive Ground Water Inflow Modeling and Sensitivity Analysis for the Proposed Crandon Mine, Thomas A. Prickett & Associates, October 1984
Nov 06, 1984	-	Report on Exxon Crandon Pump Test Response to DNR Memorandum (dated 11/15/82); Golder Associates, October 1984
Nov 06, 1984	-	Letter from Garrett G. Hollands, IEP Inc., to Dr. Joseph DeMarte, EMC, dated October 29, 1984 Re: "Wetland Water Balance Analysis - Compatibility of Methods and Results of IEP, Inc. and Ayres Associates
Nov 08, 1984	-	Final Draft, Appendix 4.1A, Hydrologic Impact Assessment; D'Appolonia Consulting Engineers, October 1984
Nov 09, 1984	-	Transportation of Reagent Materials Off-Site Risk Related Issues; Zordan Associates, Incorporated, November 1984
Nov 12, 1984	-	0.33 m (1.0 foot) Ground Water Drawdown Contour Letter to DNR
	-	Non-Tailing Mining Wastes (Ref 4400) Letter to DNR
	-	Full Size Plan Sheets
Nov 14, 1984	-	Wetlands Assessment Report; Wetlands Assessment Appendices; Wetlands Assessment Inventory Report; Wetlands Assessment Maps Normandeai Associates, Inc., August 1982
Nov 16, 1984	-	Draft - Results of Private Water Well Survey; Northern Lake Services
	-	Section D, Reclamation Plan, Revised; November 1984: EMC
Nov 20, 1984	-	Hydraulic Relationship Between Site Area Lakes and the Main Ground Water Aquifer, Crandon Project, Forest County, Wisconsin; Dames & Moore
Nov 20, 1984	-	Report on Exxon Crandon Pump Test Response to DNR Memorandum (dated 11/15/82); Golder Associates, October 1984

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Nov 28, 1984	-	EMC's Responses to DNR Comments on the EIR (Letter dated October 4, 1984) (45)
Nov 29, 1984 & Dec 14, 1984	-	Exxon Mineerals Company, Crandon Project Water Treatment Testing Program; Exxon Research and Engineerig Company, November 1984 (10)
Dec 04, 1984	-	Duck Lake, Sample Analysis Record 11/21/84, Northern Lake Service, Inc. (1)
Dec 14, 1984	-	Appendix C - Disposition of Cyanide and Dichomate in the Crandon Circuit; Exxon Minerals Company; CH2M Hill Water Treatment Facility Engineering Report, Submitted September 28, 1984. (10)
Dec 17, 1984	-	Crandon Hydrology Database Schema, Exxon Minerals Company (5)
Dec 18, 1984	-	Air Quality Permit Application Report Notice of Intent (NOI), Exxon Minerals Company (5)
Dec 19, 1984	-	Laboratory Testing of Tailing: STS Consultants Ltd., June 29, 1983. (24)
Dec 21, 1984	-	Preliminary Draft of the Monitoring and Quality Assurance Plan (Working Copy (10)
Jan 03, 1985	-	Letter from B. Hansen to K. Wade with 10 copies each of following:
	-	Scope of Work for the Lake Water Balance Study
	-	Reprint - "A Field Exercise of Ground Water Flow Using Seepage Meters and Mini-Piezometers," by D.R. Lee and J.A. Cherry
	-	Reprint - "A Device for measuring Seepage Flux in Lakes and Extuaries," by D.R. Lee.
Jan 04, 1985	-	Tax Rate Simulation Model - Operation Manual and data diskettes; Dr. Huddleston (1 each)
	-	Responses to Noise and Seismic Vibration Comments in DNR letter dated 12/28/84 (42)
Jan 09, 1985	-	Response to DNR comment letters dated September 17, 1984 and October 22, 1984 Re: Ground Water Modeling and Mine Dewatering Impact Analysis (27)

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Jan 17, 1985	-	Additional copies of Response Letter sent to DNR January 9, 1985.
Jan 18, 1985	-	Ground Water Potentiometric Contours
Jan 23, 1985	-	Lake Contour Map prepared by Inman-Foltz (10 copies and 1 sepia mylar)
Feb 14, 1985	-	Revised Air Permit Application and Appendices A, B, C, and D
Feb 14, 1985	-	Revised Chapter 1.0, Project Description, EIR
	-	Revised Chapter 3.0, Alternatives to the Proposed Action, EIR
Feb 14, 1986	-	Water Treatment Testing - Crandon Project, 84 MT-138; John L. Shafer (EMC), September 1984
Feb 15, 1985	-	Report, Revised EIR Chapters 1 and 3
Mar 11, 1985	-	Report, Mine Ventilation Study of the Crandon Mine; Volume I; S.A. Scott & Company, Inc. (December 1978)
	-	Mine Supply Air Heating Feasibility Study; Bovay Engineers, Inc. (December 1977)
	-	Revised EIR Chapter 3.0, Alternatives to the Proposed Action; EMC (January 1985)
Mar 12, 1985	-	Report, CH2M Hill, Water Treatment Facility Engineering Report, Appendix D - Decomposition of Organic Flotation Reagents, EMC (February 1985); and Appendix F - Reverse Osmosis Water Treatment Testing Program; ER&E (February 1985)
Mar 28, 1985	-	Dissolved Oxygen Survey Results for Rolling Stone Lake and Creeks 11-4, 12-9 and Pickerel Creek
Apr 05, 1985	-	Report, Appendix E - Water Treatment Sludge Characterization; EMC; April 1985 - to be inserted into CH2M Hill Water Treatment Facility Engineering Report, 9/28/84
Apr 16, 1985	-	Wastewater discharge sites from mining operations in the "New Lead Belt" of Missouri. University of Missouri. Missouri Society of Mining Engineers - Gale, N.L., and Wixson, B.E. 1977

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Apr 16, 1985	-	Dewatering high-clay content preparation plant tailings. American Mining Congress Journal. Scheiner, B.M. 1982.
	-	Construction and investigation of a clay heap leach pond, 1983 SME-AIME Fall meeting, Salt Lake City, Utah. October 19-21, 1983. Van Zyl. 1983.
Apr 16, 19 & 25	-	Hydraulic Relations Between Little Sand, Oak, Duck, Skunk and Deep Hole Lakes and the Main Ground Water Aquifer, Crandon Project; Dames and Moore, April 4, 1985
May 10, 1985	-	Report, Phase III Liner Testing, John Wallace, EMC, 1985
May 17, 1985	-	Revised Response to DNR Comment No. A28 on the Noise Reports (Original response submitted to DNR 10/31/84)
May 24, 1985	-	Report, Aquatic Monitoring in Swamp Creek, February-Decmeber 1984; EA Science and Technology, 1985
May 24, 1985	-	Preliminary Crandon Open Pit Feasibility Study, E.R. Mueller (EMC) January 6, 1977
May 29, 1985	-	Drawings, EMC Crandon Project Soil Boring and Piezometer Location Map; STS Consultants Ltd.; and EMC Ground water Potentiometric Countours; STS Consultants Ltd.
Jun 12, 1985	-	Response to DNR Comment Letter of May 7, 1985 Re: Monitoring Plan
Jun 14, 1985	-	Response to DNR Comment Letter of November 8, 1984 Re: Dames & Moore Report - Hydraulic Relationship Between Site Area Lakes and the Main Ground Water Aquifer, dated 9/20/84.
Jun 20, 1985	-	Hydraulic Relations Between Little Sand, Oak, Duck, Skunk, and Deep Hole Lakes and the Main Ground Water Aquifer, by Dames & Moore, 4/4/85
Jul 19, 1985	-	Aquifer Transmissivity Map and Cross Sections Letter
Jul 19, 1985	-	Preliminary Descriptive Packages: + Attachment I: Mine Waste Disposal Facility and Water Reclaim Pond + Attachment II: Sanitary Sewage Package Treatment Plant + Attachment III: Mine Waste Landfill - Crandon Project On-Site Facility + Attachment IV: Water Treatment Process
Jul 23, 1985	-	"Red lined" Chapter 1.0, EMC EIR

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Jul 25, 1985	-	Crandon Project lake Impact Studies, IT Corporation, 1985
Jul 26, 1985	-	Response to Memorandum of Understanding - T.A. Prickett & Assoc. Mine Inflow Modeling and Review of "Hydrologic Impact Assessment Methodology and Results" Appendix 4.1A
Jul 31, 1985	-	Letter, 34 Responses to DNR Comment Letter Dated July 2, 1985
Aug 2, 1985	-	Report, IT Corporation, Appendix 4.1A, Attachment A.10, Lake Impact Analysis and Related Hydrological Assessments
Aug 15, 1985	-	Letter, 10 Additional Responses to DNR Comment Letter Dated July 2, 1985
Aug 20, 1985	-	Letter to Richard G. Schuff (DNR) from Barry J. Hansen (EMC), dated July 26, 1985, with attachments: + Attachment I - "Deep Hanging Wall Fracturing Report" + Attachment II - "Review of Mine Inflow Modeling History" + Attachment III - "Mass Balance Summary" + Attachment IV - "Mine Inflow Sensitivity Analysis for Three Recharge Cases"
Aug 22, 1985	-	One Set of Two Floppy Disks Re: "Exxon Crandon Lake Water Balances Impact Conditions"
Aug 30, 1985	-	Letter, 17 Additional Responses to DNR Comment Letter Dated July 2, 1985
Aug 31, 1985	-	Chapter 2 - Environmental Baseline
Sep 11, 1985	-	Report, Final Draft - Lake Impact Analysis and Related Hydrological Assessments (Revised 9/9/85) (Supersedes July 1985 submittal)
Sep 11, 1985	-	Letter, 3 Remaining Responses to DNR Comment Letter Dated July 2, 1985
Oct 16, 1985	-	Monitoring and Quality Assurance Plan (Draft), EMC, October 1985
Nov 01, 1985	-	Revised "Draft" of EIR Chapter 1
Nov 12, 1985	-	Revised "Draft" of EIR Chapter 3
Nov 20, 1985	-	Revised EIR Chapter 2
Nov 22, 1985	-	Hydrologic Impact Contingency Plan (Draft), Exxon Minerals Company, 1985

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Dec 03, 1985	-	NR 110.09 Facilities Plan for The Exxon Minerals Company Mine/Mill Complex Sanitary Wastewater, Crandon, Wisconsin; CH2M Hill, Inc.: November 1985
Dec 05, 1985	-	Reclamation Plan Responses to June 17, 1985 DNR Letter
Dec 06, 1985	-	Reclamation Responses to June 17, 1985 DNR Comment Letter
Dec 09, 1985	-	Revised MWDF Feasibility Report, Exxon Minerals Company, December 1985
Dec 10, 1985	-	Hydrologic Impact Contingency Plan, EMC
Dec 13, 1985	-	High Capacity Well Approvals: + Mine Inflow Approval + Potable, Construction & Contingency Wells
Dec 16, 1985	-	Revised EIR Chapter 3, EMC, "Final", December 1985
Dec 18, 1985	-	Mine Refuse Disposal Facility Feasibility Report (MRDF), EMC, December 1985,
Dec 19, 1985	-	Water Treatment Facility Engineering Report; CH2M Hill, December 1985 (replaces September 1984 submittal)
Dec 23, 1985	-	EIR Appendix 4.1A, Hydrologic Impact Assessment
Dec 27, 1985	-	WPDES Permit Application, December 1985
Dec 30, 1985	-	Revised Environmental Impact Report, Chapter 1.0, EMC, December 1985

APPENDIX 3.4A

Information On Siting Of The Mine Waste Disposal Facility

EXXON MINERALS COMPANY

P. O. Box 813, RHINELANDER, WISCONSIN 54501

CRANDON PROJECT

July 11, 1983

Reference to 1630

Messrs. Paul Didier and Howard Druckenmiller
Bureaus of Solid Waste and Environmental Impact
Department of Natural Resources
Madison, Wisconsin 53707

Dear Messrs. Didier and Druckenmiller:

This letter addresses the comments provided by the department in your November 23, 1982 correspondence regarding our "Siting Report - Review of Potential Alternative Mine Waste Disposal Areas." These responses follow the sequence of the comments presented in your letter. Where appropriate and for clarity, we have added numbers to relate these responses to the comments of your letter.

As to the general perspective provided in the "Siting Report...," we attempted to present to the department a synopsis of the information and data we had evaluated from initiation of the Crandon Project feasibility studies until June 1982. This general perspective was based on several meetings with the department in which the department indicated their requests for the report contents. The department specifically suggested a narrative style, no matrices, and areas to be included in addition to Areas 40 and 41. The agreed upon concept was to provide a synopsis of the data collection and other considerations which were included in the mine waste disposal facility (MWDF) siting process.

Generically, the most cost-effective approach to these siting efforts is to continue narrowing the discriminating factors for such a facility until a preliminary design can be developed which assures the attainment of standards, minimizes impacts, and is economically viable. This process incorporates a progression from general to specific factors and from a large number to few sites. The few sites are then analyzed further including that amount of design and data collection which is cost-effective for ultimate selection of a proposed site. It is unrealistic and cost prohibitive to conduct field programs and design details for each area initially or potentially identified as a site. The siting process is designed to be a cost-effective approach enabling the identification of a preliminary design which meets standards for the protection of the public and the environment. Several sites may ultimately accomplish these objectives. However, once such a site is determined, it is unwise to expend funds designing such a facility for several sites.

I. through VII. The DNR's comments provide an accurate review of the submitted information contained in the consultant reports. Additional comment from Exxon is not warranted.

VIII. Comment Noted.

AREA 30

1. Phase I essentially consisted of two reports as reviewed by the DNR in their comments I and II of the November 23, 1982 letter. In the report described in your comment I, Area 30 was identified as a potential upland site. However, the report described in your comment II did not recommend additional study for Area 30. Therefore, at the end of Phase I, Area 30 was not recommended for further analysis in Phase II.

2. The reference cited in the "Siting Report" regarding the ground water gradient includes boring logs as well as several figures detailing bedrock, ground surface and ground water elevations. All of these data indicates a ground water gradient sloping downward toward the southwest to Gliske and Swamp creeks and Rice Lake. Similarly, an interpolated ground water table map in the ground water study report (see Dames & Moore 1982a, p. 11) also indicates this gradient.

3. The depth to ground water is a generalization of the range in differences between the ground surface elevations and the interpolated ground water table. The data evaluated included the two borings drilled in Area 30 as well as the surface water elevations.

4. The designation of area boundaries throughout the consultant reports and the "Siting Report"... was not designed to be specific to ground surface landmarks. The Area 30 designation is a generalization. As indicated in the Engineering Design section, a large ground surface acreage would be needed for a mine waste disposal facility. Although no specific design or earthwork requirements were developed, it was expected that the large surface acreage needed would ultimately infringe on the roads and airport in Area 30. Since Area 30 was eliminated from further evaluation in Phase II, no detailed cost estimates of road or airport relocation were developed.

5. The Golder Interim Report emphasized and provided greater detail on early designs for Areas 40, 41 and 50. However, p. 14 of this Golder report summarizes earlier work which eliminated certain locations. They do not specifically state Area 30 but Golder did eliminate this location citing the Crandon airport as the primary reason. An additional citation for Area 30 evaluation could have been Golder (1979) as referenced in other portions of the "Siting Report..."

6. Groundwater levels in wells on the north and south sides of Area 30 and ground water discharge elevations at Gliske and Swamp creeks and Rice Lake

indicate there is no ground water divide in the Area 30 site. The ground water flow through the area is to the southwest to Gliske Creek, Rice Lake, and Swamp Creek. Topographical maps indicate Area 30 is in one surface watershed which either drains to the south to Swamp Creek or to water table wetlands in the lower elevations of Area 30. (See Golder Associates' Geohydrologic Characterization Report, Figures 4.1 and 5.3).

7. The depth to ground water in Area 30 is in the range of 3 to 6 m (10 to 20 feet) throughout most of the area. If a MWDF were designed for this area, we would probably try to maintain pond bottoms at least 3 m (10 feet) above the ground water level to minimize construction problems. This potential 3 m (10 feet) separation is in contrast to the approximate 15 m (49 feet) of unsaturated till and additional 20 m (65 feet) of saturated till below the MWDF bottom at Area 41. Assuming other factors are equal, attenuation capacity of the sites could be proportional to the depth of separation or, in this case, Area 41 would afford greater ground water protection.

   Although no MWDF layouts have been prepared for Area 30, it is possible to roughly estimate earthwork requirements. For Area 30 nearly the full height of the pond embankments would have to be built above existing grade and there would be minimal excavation associated with the MWDF.

   For the conditions in Area 30 a MWDF with shallow ponds and lower embankments would be constructed more efficiently; however, a much larger surface area would be necessary.

   For the construction of a four pond facility similar to 41-114B there would be as much as 15 to 20 M m^3 of embankment requirement versus only 1 to 2 M m^3 of excavation. In addition, another 6 to 8 M m^3 of earthen material would be required for reclamation, liners, and drains. Altogether, a borrow volume of 20 to 25 M m^3 would be required to develop a MWDF in Area 30 following the assumptions noted above. It is probable that this quantity of borrow could be obtained within 3.2 to 6.4 km (2 to 4 miles) from Area 30. For instance, the hill just west of Oak Lake on Little Sand Lake Road is 4.8 km (3 miles) from Area 30 and has an estimated potential borrow volume of 7 to 8 M m^3.

   As the siting report notes the permeabilities of the soils in Area 30 are relatively high compared to those in other areas, making them a less desirable choice as a natural liner or for a bentonite modified soil liner.

   Although no attenuation tests were conducted on Area 30 soils, based on the overall generally similar characteristics of the soils in the Regional Area, it is assumed their geochemical characteristics would be similar also.

   Area 30 was not carried far enough along in the siting process to warrant study of contingency measures. Efficient contingency measures are dependent upon MWDF configuration as well as area geohydrological characteristics. As indicated above, an Area 30 MWDF with large areal coverage, while most appropriate from a construction efficienty standpoint, would have different appropriate (and probably generally less effective because of the MWDF size) contingency measures.

AREA 31

1. Depth to ground water was interpolated from the site and surrounding area borings, the ground surface and bedrock elevations, the surface water elevations, and information on water supply wells in the vicinity. (See Golder Associates' Geohydrologic Characterization Report, Figure 4.1).

2. Boring DMA-22B was carried to a depth of 32 m (105 feet) with no bedrock encountered. Two seismic survey lines in the area (conducted by Geoterrex Ltd.) provided most information on bedrock depth. (See Golder Associates' Geohydrological Characterization Report, Figure 3.5).

3. Drainage from Area 31 wetlands is generally toward the nearest adjacent surface water body. For Area 31, this is mostly toward Hemlock Creek and Ground Hemlock Lake. Although no wetlands were specifically studied in relation to surface water elevations, it could be possible that any reduction in water quantities to the lakes from wetlands would reduce local lake levels.

4. Costs of Soo Line Railroad or County Trunk Highway W relocation for Area 31 can be approximated from the costs developed for the new road and railroad into the mine/mill site. Estimated total costs (including contingency but no land cost) were approximately \$350/m (\$107 per foot) for the railroad and approximately \$280/m (\$85 per foot) for the road according to estimates prepared by Foth & Van Dyke and Associates, Inc (Preliminary Engineering Final Report Mine/Mill Access Road (August 1982), Appendix 7-Cost Estimates and Preliminary Engineering Final Report-Mine/Mill Railroad Spur (December 1981), Appendix 6-Cost Estimates). MWDF layouts have not been prepared for Area 31 so only very rough estimates can be made for roadway and railroad relocation costs. From the approximate layout of Area 31 it appears that up to 1.6 km (1 mile) of roadway and up to 3.2 km (2 miles) of railroad could be affected which would have an associated cost of approximately \$1.6 million. Depending upon the MWDF arrangement in Area 31, it might be possible to avoid one of the corridors and reduce the relocation cost.

5. Comments Noted.

AREA 40

1. For most of Area 40 the distance from the existing ground surface to the ground water table is in the range of 15 to 30 m (49 to 98 feet). Ground water elevation at the middle of Area 40 is approximately 477 m (1,565 feet).

The study of Area 40 with respect to specific layouts was performed at the time when Areas 40, 41, and 50 were under consideration. Layouts for each area were prepared; however, they were not completed to nearly the detail that site 41-114B has been. Earthwork comparisons were very approximate between the areas. Also, when the layouts were made, separation of pyrite and non-pyrite tailings was still being considered, which meant that the bottoms of the non-pyrite ponds were unlined and not graded so that existing ground surfaces were used for design. It is probable that if layouts in Area 40 were designed to the same level of detail and with the same criteria applied as they have been in Area 41, the pond bottoms would be located at least 10 m (33 feet) below existing grade, in order to achieve an approximate balanced earthwork condition. With an overall average existing ground surface elevation of approximately 500 m (1,640 feet) in Area 40, the pond bottoms would be at approximately 490 m (1,608 feet) and there would be a separation of approximately 13 m (43 feet) between pond bottoms and the ground water table.

The soils data available in Areas 30, 31, and 42 are much more limited than that for Areas 40 and 41 and suitable only for the general soils characterizations made in the Siting Report. In areas 40 and 41, however, the more detailed soils sampling, testing, and interpretation work does show significant thinning of the upper till in Area 40 compared to Area 41. If comparable facilities were constructed at each area, there would only be about 10 m (33 feet) of till below the bottom of an MWDF sited in Area 40 compared to approximately 40 m (131 feet) in Area 41.

2. Detailed data were obtained as design comparisons were warranted. Where comparable data from other areas were not available, the most favorable interpretation for the area was assumed so that it was not the single factor eliminating a site from further consideration. For example, carbonate content of the till for all areas was considered positive with an assumed range from 1 to 9 percent which is sufficient for attenuation of acid or metals. Areas without till were considered less favorably.

3. The statement on p. 26 says that <u>some</u> contingency measures may not be totally successful. For example, cutoff walls would most likely be inadequate for the large area of these ground water flow paths. Therefore, no specific contingency measure was designed or proposed for Area 40. However, if a waste disposal design for this Area would have been proposed, a workable contingency plan would have been evaluated and designed to assure meeting compliance boundary requirements.

4. Although an access corridor to Area 40 has not been planned in detail, it would generally be southwest from the mine/mill site between Little Sand Lake and Oak Lake. The archaeological site in this area would be an additional restriction to consider in planning a route through this area.

5. Comment Noted.

6. The important earthwork factors in comparison of Area 40 to all other areas are the amount of earthwork, location of borrow areas and the associated environmental impacts, and the costs.

   It is our understanding that the Town of Ainsworth passed a mining moratorium resolution which in part states "...there is hereby imposed a moratorium on all metallic and uranium related mining activities in the Town of Ainsworth for a period of 10 years." Exxon has not had any formal discussions with the Town of Ainsworth although presentations on the environmental compatability of the Crandon Project facilities have been completed for members of the Rolling Stone Lake Association.

7. Creeks 11-4 and 12-9 are trout streams (see Figure 2.9-3 of the EIR). The citation in the "Siting Report..." should have been Dames & Moore 1982b.

8. Comment Noted.

9. Comment Noted.

10. The Dames & Moore studies were completed very early in the siting process and no geotechnical data were available. The perched upland wetlands are evidence for such impermeable soils. This same report (Dames & Moore, 1979) and later Dames & Moore and Golder reports indicate a range of permeability for the till soils and indicate their suitability as a liner. This is further supported by later lab tests which evaluated bentonite additions to the till to assure and enhance low permeabilities for a till soil liner.

11. If a specific Area 40 design had been proposed, a contingency plan would have been provided as specified in NR 132 and NR 182. At this time other possible contingency measures such as cutoff trenches or grout curtains may have been evaluated. However, there was no need to evaluate these measures for the "Siting Report...."

12. Portions of Area 40 not located in Langlade County were evaluated as part of the Area 50 alternative, and included portions of Golder Area B. No viable site was determined from this evaluation.

<u>AREA 41</u>

1. Rolling Stone Lake is down gradient with respect to its ground water table elevations' from Area 41, however, it is approximately 5 km (3.1 miles) away. There is no evidence of any separate aquifer system connecting Area 41 to the Rolling Stone Lake area; any ground water flow between the two areas would occur in the main aquifer which is continuous throughout the area.

   In the study of ground water effects, seepage from the reclaim ponds was considered. With the double liner proposed for the reclaim ponds, the seepage rate from them is estimated to be approximately 0.000012 $m^3/_s$ (0.2 gpm) and the ground water effect from seepage was negligible.

The study work (EIR Appendix 4.1A) indicated the MWDF met ground water quality requirements at the compliance boundary and the Little Sand Lake area residents are well outside the compliance boundary.

2. Portions of the total ground water recharge from Area 41 would move toward Hemlock Creek. Ground water which would move in this direction must meet the NR 182 standards at the compliance boundary which is between the MWDF and Hemlock Creek. Contaminant transport modeling (EIR Appendix 4.1A) indicates any MWDF seepage moving in the direction of Hemlock Creek meets NR 182 standards at the compliance boundary.

3. The statements on p. 32 of the "Siting Report..." are correct. For further discusion of ground water flow directions and velocities see Appendix 4.1A of the EIR. In particular, see Figures A-19 and A-30 of the EIR Appendix 4.1A for ground water flow directions. In these figures the length of the arrows is proportional to the magnitude of the ground water flow. The figures show ground water flow in all directions from the ground water high in Area 41 but with the greatest flow rates generally to the west and southwest.

4. There are currently no year-round or full-time residents living on Little Sand Lake.

5. Comment Noted.

6. The Golder 1981b report was the correct citation for p. 34 of the "Siting Report..." and not the pumping test report; however, the average permeability noted in that report (Table 4.1) is $1x10^{-7}$ m/s not $1x10^{-7}$ cm/s. The pumping test results in Area 41 provided a calculated vertical permeability in the till of $9.4x10^{-7}$ m/s or approximately $1x10^{-4}$ cm/s. The estimated horizontal permeability of the till from the pumping test results was $2.8x10^{-6}$ m/s. Other data (see Golder, 1981b) including Dames & Moore and D'Appolonia test results provide values for till permeability as low as $2.5x10^{-10}$ m/s or $2.5x10^{-8}$ cm/s.

7. For tailings pipelines, with an appropriate pipe size to transport tailings and water at a sufficient velocity, there is substantial pressure (head) loss as a result of friction. For the 41-114B tailings pumping system with a total head loss approximating 168 m (550 feet), approximately 122 m (400 feet) is from friction loss over the pipe length, 37 m (120 feet) is from elevation change, and the remaining 9 m (30 feet) is for a discharge head. For the areas considered, the overall system length is the more important factor when comparing pumping requirements. For instance, if the overall pipeline system length in Area 40 was equal to that of Site 41-114B, the facility might have a 10 m (33 feet)

elevation advantage, but its overall pumping horsepower requirement would only be approximately 5 percent less.

8. The range in ground surface elevation in the two areas and the actual Area boundary chosen would affect the comparative depths to ground water Our estimates indicated an average soil depth to the ground water table in Areas 40 and 41 of approximately 23 m (75 feet) and 26 m (85 feet), respectively.

9. Refer to Figure A-19 of the EIR Appendix 4.1A for a modeled representation of the ground water flow in the simulation area. From the higher ground water elevation in Area 41 there is radial ground water flow; however, the figure shows greater flow rates to the west and southwest.

AREA 42

1. Boring G41-C32 is located on the north side of Area 42. This boring was drilled to bedrock and a piezometer was installed. Soil samples were taken periodically throughout the borings depth to provide soil material information.

2. A strict interpretation of the lines designating Area 42 would indicate that Creek 13-15 does not originate there. However, the watershed and probable water quantity of Creek 13-15 would be potentially affected by facilities in Area 42.

3. Comment Noted.

4. The siting studies did not attempt to define treated water discharge locations.

5. The ground surface elevations in Area 42 range from approximately 533 m (1,750 feet) in the northeast to approximately 494 m (1,620 feet) in the southwest.

6. Comment Noted.

We have identified your "More general comments..." section beginning on p. 10 of the November 23, 1982 letter as section IX.

IX

1. Specific references to report, page, figure and title number are provided in this letter. Also the Reports Cited section on p. 46 of the "Siting Report..." included all references used in its preparation. If there are additional specific instances where DNR cannot find the data indicated, please identify them and we will provide the pages of the document that should be reviewed as was done in various responses of this letter.

2. Comment Noted.

3. Although the criteria of "volume of aquifer threatened" has been weighted in the siting process, it is not considered to be of primary importance. There are many other factors that must be considered in conjunction with the "volume of aquifer threatened" before a reasonable comparison and evaluation of alternate areas can be completed. Our siting process included these factors.

   Tradeoffs between areas that potentially threaten ground water systems versus those that threaten surface water systems are difficult. Also, areas that potentially might threaten a larger volume of the ground water system, but in turn have other features (such as a much thicker till layer) that lessen the possibility of the event occurring, are preferential factors for siting.

   Response No. 5 on page 10 contains additional considerations that are pertinent to the feasibility of contaminated ground water pumping as a contingency plan and general aspects of how area differences would affect a pumping plan.

   If a detailed analysis of the "volume of aquifer threatened" were made, then aquifer thickness and other characteristics should be considerations, however, for the fairly uniform aquifer conditions throughout the area, an areal estimate can provide an approximate comparison between areas. Also, to complete an analysis of this type a rate and period of seepage flow would have to be assumed.

   As the design of the MWDF has evolved, this criterion of "volume of aquifer threatened" has had less and less importance. With the seepage control system proposed, MWDF seepage is reduced to very low levels. The geohydrological modeling work has shown the importance and value of large separation distances from the bottom of the MWDF to the main aquifer. By taking advantage of this feature in the siting study the need to consider "volume of aquifer potentially affected" is lessened.

   In the final analysis, while the selection of Area 41 was made using many criteria, the MWDF as designed does meet the ground water quality requirement established by NR 182. This is true even with the many "worst case" assumptions that have been incorporated in the overall geohydrological study and modeling effort.

4. We agree that off-site soil requirements would magnify impacts. Although no specific designs were completed for each area, a basic indication of requirements can be completed utilizing a ground surface estimate of approximately 500-600 acres. For comparison purposes this is sufficient and does not require specific designs for each area.
   Generally, the areas with little relief or with high ground water levels would require large material borrow volumes from other locations. The earthwork requirements for the MWDF under these conditions would be severe unless large, shallow ponds were developed which would then impact a larger surface area than 500-600 acres. The engineering design segments

presented for each area were intended to address this aspect of the MWDF development. Potential borrow sources of the size required have not been identified in the project site area. However, based on site area topography it is likely that all necessary borrow material could be obtained within 3.2 to 6.4 km (2 to 4 miles) of the ore deposit.

5. The concept of ground water pumping has been proven and accepted as an effective contingency measure in controlling or correcting ground water contamination. The Contingency Plan summarized in the Feasibility Report is presented as a conceptual plan that would provide for further study depending on the failure mode, chemical element(s) of concern, and applicability of different contingency measures. The Contingency Plan provided indicates the sequence of events through which this study would proceed.

Our studies have identified, in concept, additional contingency measures that might relate to potential Seepage Control System failures by a number of different means. The attached report "Operating Aspects and Contingency Plans - Seepage Control System" (Attachment No. 1) presents this information.

The geohydrological study and modeling work completed for the Crandon Project has been helpful in the continued study of potentially viable MWDF failure contingency measures. The large separation distance from the MWDF bottom to the ground water table and the permeability of the till result in long percolation times (i.e. hundreds of years) which will allow attenuation, dispersion, and diffusion effects to occur. However, the geohydrological modeling work and the field pumping test of ground water do demonstrate the significant extent of ground water gradient control available through pumping. As indicated in the Contingency Plan there would need to be study of the particular failure for the MWDF before a final pumping program could be suggested. Actual plans for a given facility could vary significantly depending on the mode, location, areal extent, and severity of the failure.

Although Area 41 is a ground water high within the modeled area, the gradients throughout the area are not severe. The area of influence or gradient control for a given pumping rate, with these moderate gradients and fairly uniform aquifer conditions, would not be greatly different from area to area.

With the additional contingency measures available for the MWDF as presented conceptually in the attached report and with the understanding that conceptually, ground water pumping would provide a final, last resort type of corrective action, we do not feel it would be productive to define a contingency pumping plan further at this time. Also, with the evolution of the MWDF design, particularly its seepage control system, and the corresponding studies of its constructability (Indeco; Construction of Waste Disposal Facilities) and predicted performance, (D'Appolonia; EIR Appendix 4.1A) we have not attached a high relative weight to "contingency measures" as an area selection criteria especially in relation to more important criteria such as standards.

6. The Golder Interim Report (1980) which examined and compared Areas 40, 41 and 50 included an estimate of the wetlands which might be potentially affected by siting facilities in these areas.

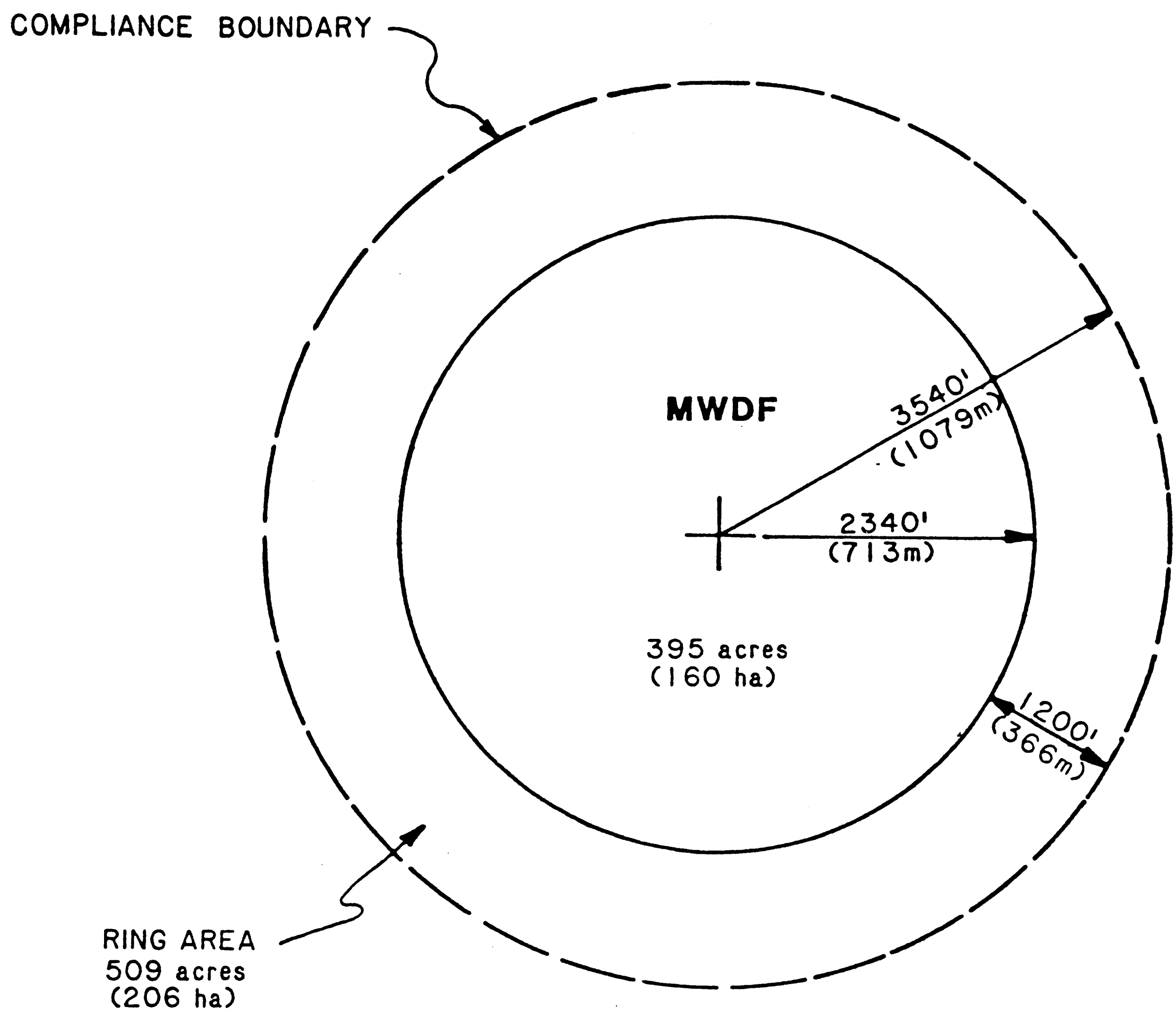
7. The combination of ground surface and surface water body elevations is a general indication of likely ground water table gradients. Figure A-19 of Appendix 4.1A in the EIR provides actual ground water flow rate estimates and contours used in determining ground water hydraulic gradients. Although Areas 30, 31 and 42 are outside of the modelled region in Figure A-19, the ground water gradients have been established from water supply wells, some borings, and some lake and stream data.

8. In general the figures presented in the "Siting Report..." show the relationship of Areas 31, 40 and 41 to surface water in the region. Where potential siting concerns were addressed, such as the 305 m (1000 feet) distance restriction for facility location or the identification of a surface water body as a designated trout stream, this information was presented in the "Siting Report..." Where surface water bodies were not of concern, they were not mentioned.

9. The "Siting Report..." indicated where possible the depths from the ground surface to the ground water table and/or bedrock. Where estimated design pond bottoms were evaluated, this information was also provided in the "Siting Report..." Average soil depths to ground water for Areas 40 and 41 are presented in Response No. 8 for Area 41 comments.

10. Areas 40 and 41 have been compared for specific MWDF designs and these comparisons are available in the Golder Associates Interim Report for Waste Facility Siting submitted to the department. No comparable MWDF layouts were completed for Areas 30, 31 and 42. However, it is possible to evaluate these areas based on their general characteristics. For example, if a MWDF design similar to 41-114B (approximately 500 surface acres) were developed for Areas 30 and 31, they would be similar. Because of the near surface ground water table in these areas, an earthwork imbalance between cut and fill would occur. If shallower ponds are constructed, a better earthwork balance could be achieved but the surface acreage required would increase as well as the potential impacts. Because of the lower ground water table in Area 42, earthwork requirements would be similar to Area 41. In this case, the pumping system capital and operating costs for the pipeline to and from a facility in Area 42 would be much higher than for Areas 40 and 41, primarily because of the much greater distances involved. Pumping head losses from elevation changes would be small in comparison (see also Area 41, Response 7).

11. The attached figure (MWDF Seepage Dilution Analysis) illustrates a principle that is appropriate for considering potential aquifer contamination. The figure shows a simplified representation of a MWDF of



TOTAL INFILTRATION TO RING AREA

Normal infiltration 0.22 m/y (8.66 in/y)
Steady state MWDF seepage 0.021 m/y (0.83 in/y)
(D'Appolonia; EIR Appendix 4.1A, Figure A-3)

(Normal infiltration to ring area + excess of infiltration over seepage through MWDF area)

$206 \text{ ha} \times 10000 \text{ m}^2/\text{ha} \times 0.22 \text{ m/y} + 160 \text{ ha} \times 10000 \text{ m}^2/\text{ha} \times (0.22 - 0.021) \text{ m/y} = 773{,}200 \text{ m}^3/\text{y}$

SEEPAGE THRU CAP (BECOMES MWDF SEEPAGE)

$160 \text{ ha} \times 10000 \text{ m}^2/\text{ha} \times 0.021 \text{ m/y} = 33{,}600 \text{ m}^3/\text{y}$

$$\text{Dilution Ratio} = \frac{\text{Seepage Through Cap}}{\text{Total Ring Infiltration}} = \frac{33{,}600}{773{,}200} = 0.043$$

EXXON MINERALS COMPANY

CRANDON PROJECT

MWDF SEEPAGE DILUTION ANALYSIS

COUNTY: FOREST	STATE: WISCONSIN
SCALE: NONE	
DRAFTED BY: DR SPRINGBORN	DATE: 6/83

the size necessary for the Crandon Project and also includes the 366 m (1200 foot) compliance boundary. Based on an average infiltration rate of 0.22m/y and assumed MWDF steady state seepage rate of 0.021m/y, the calculations indicate average dilution ratios that would be experienced in the conceptual system. The figures indicate that at the compliance boundary the average concentration of any seepage from the MWDF would be only 4-5 percent of what it was originally.

The geohydrological modeling work Exxon has performed includes this principle and further extends it by incorporating ground water gradients to determine how the projected seepage pattern or plume would be reshaped.

Ground water gradients would vary from area to area and the shape of the plume would be altered accordingly, however, on the average, the dilution ratio at the compliance boundary would still be 4-5 percent. In the case of Area 41 the modeling study indicates the proposed 41-114B facility reaches a maximum steady state concentration of less than 13 percent in the direction of maximum gradient at the compliance boundary. To maintain the approximate 4-5 percent average dilution ratio there would be other areas along the boundary with concentrations less than 4-5 percent.

Detailed modeling study in other areas would result in different maximums according to ground water gradients in the area but the average concentration levels at the compliance boundary would be in the 4-5 percent range.

Basically, we feel this principle as outlined above, which represents the performance mode the proposed MWDF would have in any area, should be considered when estimating potential aquifer contamination of one area versus another. These considerations, along with those presented in Response No. 3 of Item IX, form the basis for the lower relative weight we attach to the criterion of "volume of aquifer threatened."

12. The design of the MWDF has evolved over the course of 4-5 years of study to the point where it is similiar in many aspects to state of the art design for hazardous waste facilities. Basically, the overall conservative approach taken throughout the course of the many studies associated with the mine waste disposal facility has resulted in this design. The main features of the MWDF design relate to the seepage control system, both the pond bottom system which functions primarily during operation, and the reclamation cover, which provides long term protection to the ground water system. These features do represent extensive engineering modification to an area when contrasted to an unlined or even a lined but undrained facility. However, based on study of the regional area we would not have a substantially different seepage control system regardless of the location of the MWDF.

Assuming that the facility design with respect to seepage control would remain similar from area to area, it would be reasonable to select an area that complimented the design most favorably. With its low seepage rates the deep till soils and low ground water depths of Area 41 enhance the performance of the MWDF. While we feel the attenuation related comments are appropriate, we do not have evidence or expect that these characteristics change much within the study area, therefore the areas with deeper till and greater depths to ground water would be more favorable from an attenuation standpoint. Additional attenuation information is presented in D'Appolonia's report "Soil Attenuation Study", previously provided to the DNR.

13. See Area 41, Response 1.

14. The USGS maps utilized in the Terrestrial Ecology Report are old and do not show the wetlands in Area 31. The type and extent of wetlands in Area 31 were provided to the department in several briefings.

We have identified your "General Comments..." section beginning on page 12 of the November 23, 1982 letter as section X.

X.

We conducted many coordinated studies during the siting process. This process followed the steps of A., B., and C. as suggested in your letter. As you indicate, the data to successfully develop these steps are available and we attempted to consolidate them for you in the "Siting Report..."

1. The basic conclusion reached by Exxon and its consultants (Dames & Moore and Golder) was that areas beyond a 5-mile radius did not offer better features with respect to MWDF Siting. Thus, because of the additional costs and impacts that would always accompany a more distant site, there was no reason to continue study beyond the 5-mile distance. See Area 41, Response 7 and section IX, Response 10. The DNR has been furnished most reports cited in the "Siting Report...", Feasibility Report and EIR. Additional reports will be furnished at the DNR's request.

2. All potential sites were evaluated with comparable data to the point in the process where further study was no longer warranted. After this time, it is no longer cost-effective to collect data or develop designs for sites which have been eliminated by earlier criteria. See also the general comments at the beginning of this letter.

3. Prospective site design was utilized in the siting process as indicated in the "Siting Report..." Several site-specific aspects such as alternative liner material were also considered and are provided in Chapter 11 of the Feasibility Report. The comments of the DNR within this question No. 3 provide a summary of the background for the answer to Response No. 2 above.

4. Basically we concur with the DNR's comment and it is one reason we did not rely solely on matrix evaluations. In addition, other matrix criteria or

values could be used as suggested by the DNR. We conducted additional studies to aid in the evaluation of our earlier results. It was from such studies and evaluation that we decided the additional buffer zone for eagle nests was warranted to assure their nesting areas are not disturbed by mining activities.

5. See Responses No. 2 and 3 above as well as the introductory sentences to this letter.

6. Comment Noted. No sites were eliminated because of unique features.

7. See Response No. 2 above. Wetland information from area to area was comparable in detail at the time this was considered. Detailed wetlands reports have been provided to the DNR which cover Areas 40 and 41 reflecting the additional information considered when evaluating these areas.

8. Results of the ground water pumping test conducted in the summer of 1980 in Area 41 have been considered in the development of the Contingency Plan for the Crandon Project. Similar pumping Contingency Plans would also work in Area 40 as indicated in Response No. 5 in Section IX. As indicated in that response, the Contingency Plan is considered to be conceptual in level of detail and more study would be necessary for a particular failure mode before a detailed plan would be prepared. Also, as presented in the paper accompanying that response, there are other contingency measures available that would be evaluated and perhaps implemented before resorting to pumping depending on the failure mode, chemical element(s) of concern, and the evaluation of other contingency measures.

9. This data and information has been provided to the DNR in the Feasibility Report and associated references provided the department in support of the Feasibility Report. The geohydrological modeling work by D'Appolonia (presented as EIR Appendix 4.1A) and the attenuation study also by D'Appolonia are the primary reference documents.

10. The waste volumes as presented in the Feasibility Report are correct. The MWDF design volume is based on the following relationships and criteria.

   o The estimated orebody size of 65.78 M metric tons has a contingency allowance of 17 percent to 77.0 M metric tons.

   o Metallurgical grind testing and planned size split for backfill result in a overall ratio of 43 percent of orebody material becoming tailings for disposal; 43 percent of 77.0 M metric tons is 33.1 M metric tons of tailings for disposal.

   o Laboratory testing and experience from other facilities has resulted in use of an average void ratio for the deposited tailings of 1.1. With an average specific gravity of 3.22 this leads to an in-place density of 1.5 t/m^3. At this density the volume of tailings for disposal is 22.1 M m^3.

- o Estimated volumes of 0.25 M m^3 and 0.1 M m^3 for treatment plant and reclaim pond sludges are added to the tailings volume for a total waste disposal volume of 22.45 M m^3.

- o A contingency allowance of approximately 6 percent in waste volume (1.42 M m^3) is added to the 22.45 M m^3 estimate resulting in a total design waste volume of 23.87 M m^3.

- o The loss of storage in each pond (from the sloping tailings beachs) is estimated at 15 percent. Applying the 15 percent storage volume loss to the total design waste volume results in a total MWDF storage volume of 27.47 M m^3 based on a level surface through the high point of the disposed tails.

- o From the high point of the disposed tails an additional 0.91 M of embankment height is provided.

11. Minimizing impacts to all ecosystems was a siting process criterion. Swamp Creek was included in this evaluation.

12. Disposal site alternatives are presented in the Feasibility Report and Chapter 3 of the EIR.

13. Support documents were provided to the department as reference material to citations in the "Siting Report..." or early study submittals to the department.

We have identified your "Disposal Pond..." section beginning on page 15 of the November 23, 1982 letter as section XI.

<u>XI</u>.

The proposed MWDF (System 40-114B) employs a 0.15 m (6 inch) bentonite modified soil liner as discussed in the Feasibility Report including alternatives. Laboratory work by Golder Associates tested bentonite soil mixes with a range of bentonite content from 0 to 12 percent. The soil samples used were obtained from the coarsest end of the soil material size range collected in the field. The results of all of the tests showed a bentonite content in the range of 2 to 6 percent achieved a permeability of 5×10^{-8} cm/s (1.6×10^{-9} feet per second). For the proposed liner, bentonite content would be adjusted, via a rigorous ongoing quality control testing program to meet field permeability requirements. Seepage control from the MWDF depends in large measure on the tailings underdrain system which removes the head of water on the liner. This system is a much more effective means of reducing seepage than simply thickening the liner.

1. Indeco, a civil works contractor, has prepared a construction development plan and studied various construction methods for the mine waste disposal facility. Their reports have been provided to the department.

   Mixing in place, a traveling mix, and a central mix with haul alternatives were studied for installation of a bentonite modified soil liner. We feel that all of these alternatives are capable of producing the desired liner performance. Soil processing to remove oversize material, provide moisture adjustment, allow for bentonite addition, and mixing, all regulated under controlled conditions at a batch and mixing plant offers the maximum quality control. However, because it is the most costly alternative, Exxon will continue to study other construction alternatives capable of achieving the same results.

   With the underdrain system maintaining a seepage gradient of approximately unity across the liner, any seepage through the liner is primarily related to liner permeability and not to liner thickness Our calculations, as shown in the Feasibility Report (page 11-18), indicate a 5 to 8 cm (2-3 inch) liner is adequate with respect to seepage quantity; however, a 0.15m (6 inch) liner thickness has been proposed. Liner thickness to attain this permeability is assured through the planned liner construction quality control procedures.

   The installation of the liner includes initial subgrade preparation prior to placement of the bentonite modified soil liner material. This would include a fine grading with a grid of grade stakes to assure tolerance control on the subgrade and bottom liner surface. The prepared liner material would be dumped, spread, compacted, and final graded, again through use of the grade stakes, to assure tolerance control of the liner upper surface. A final step would include removal of the grade stakes and hand plugging of the holes. The liner is then protected with the underdrain layer, a filter layer, and in areas where there will be ponded water, waste rock. Once in operation, the tailings themselves become an additional protective layer.

   A mix in-place alternative would be accomplished by first spreading a uniform distribution of bentonite on the surface. Mix in-place equipment would then mix bentonite and soil to the prescribed depth to be followed by compaction and grading.

   The traveling mix alternative utilizes specialized equipment to provide batching capability with the traveling plant. Excavated material is batched with bentonite, mixed, and then relaid and compacted.

2. Testing as indicated in the Feasibility Report and the Soil Attenuation Study have not shown any incompatibility between a bentonite modified soil liner and the tailings leachate. Suppliers also offer a host of treated bentonites that can be specifically prepared to accommodate various wastes. However, probably the overriding consideration is that the bottom liner does not have to function indefinitely; it serves its purpose while

a tailings pond is in operation with the underdrain system functioning. After the pond has been filled and sealed with the reclamation cap, the underdrain system is operated long enough to remove excess water from the tailings. Ultimately, it is the reclamation cover that determines the seepage rate from the disposal pond. Once the MWDF reaches a steady state condition, the seepage from the bottom of the pond equals the seepage passing through the reclamation cover.

3. We believe there is ample evidence of the seepage control ability of bentonite clays in liners and many other applications based primarily on its widespread use and acceptability. Because the performance of a seepage control system is dependent on many factors, it will be difficult to look to existing systems and predict results. If a comparatively effective liner (from the standpoint of performance and cost evaluation) could be developed from a local natural clay, it would be equally acceptable.

4. Additional detail covering the underdrain system and calculation for alternative seepage control systems are presented in the Feasibility Report. More detailed study is presented in the Golder Associates Underdrain Report. The concept or principle of an underdrain, similar to any application of a drainage blanket, is well established. Criteria for sizing of the drain material and , if necessary, the filter material is also well established. These criteria are used to assure the performance of the various materials and of the total drainage layer. In the proposed system the filter layer (till material of intermediate size) acts to prevent any migration of tailing (fine material) into the drain layer (coarsest size material of till). Particle migration leading to drain choking normally is associated with water flow rates where there is sufficient water velocity to transport a soil or other particle. This type of condition is not anticipated in the tailing pond; however, if it did occur, it would be restricted to the upper few centimeters of the till filter layer and have no effect on the drainage layer capacity. If the till filter layer clogged, it would in effect become a double liner system.

The tailings are the least permeable layer above the underdrain and once they cover the pond bottom, they restrict water flow to the underdrain. Because of the tailings small particle size they retain water that will continue to drain after the tailing ponds are closed and the reclamation cover has been installed. Operation of the underdrain pumps is scheduled to continue after the reclamation cover is constructed to recover this delayed tailings leachate. The underdrain system is planned with three pumps per pond, with one pump being adequate to handle anticipated seepage. This redundancy assures continuous availability of underdrain pumping capacity. Additional discussion of these aspects of the MWDF seepage control system is included in the attached report "Operating Aspects and Contingency Plans - Seepage Control System."

Because of the conservatism planned in the seepage control system and the available contingency measures to assure acceptable seepage rates, an evaluation of the effects of full head seepage rates was not performed. Seepage rates for these different conditions were studies prior to design of the seepage control system. Those studies are presented in the Golder Reports, Underdrain Review, March 1982 and Parametric Seepage Rate Estimates, March 1982, previously submitted to the DNR.

5. Results of studies indicate additional intermediate interceptor pipes would not offer major improvement in the system performance (Golder Associates Underdrain Report). However, that type of change is not viewed as a fundamental change in concept. If additional study showed intermediate pipes to be beneficial, they would be added during final engineering. However, for the long-term the underdrain system is not important to the steady-state performance of the MWDF. Similar to the liner, the underdrain system serves its purpose during the operational period and for a few years after reclamation of the tailings pond. Details of the seepage control system of the MWDF are included in the set of preliminary engineering drawings accompanying the Feasibility Report. The seepage control system was designed to avoid the need to penetrate the MWDF liner.

6. The Feasibility Report contains additional information on tailings chemistry and reference to the study of possible acid conditions developing in the tailing ponds (Sections 3.3.2-3.3.4 of the Feasibility Report). The data and analysis indicate there is sufficient carbonate buffering capacity within the tailings to prevent the production of acid leachate.

Based on the infiltration that will enter the tailings through the reclamation cover (estimated at 21.5 mm/y, 0.86 inch per year), the following relationship between leachate pH level and years of available buffering capacity can be established:

Acid Neutralization Capacity of Tailings

Assumed pH from Acid Generation	Years to Consume $CaCO^3$
3.4	890,000
2.4	89,000
1.4	8,900

This degree of available buffering capacity indicates acid conditions will not develop and are not a concern for liner failure.

Soil attenuation studies were performed by D'Appolonia and that information is presented in their report "Soil Attenuation Study", previously provided to the DNR.

Additional potential contingency measures are dicussed in the attached report "Operating Aspects and Contingency Plans - Seepage Control System."

7. The Feasibility Report and EIR present the methods for the tailing ponds development, operation and reclamation. Early in the study and planning process for the MWDF it was assumed that the tailings would be deposited under water, following typical practices in the mining industry.

Therefore, tailings oxidation and fugitive dust would be minimal. In the continuing study of the MWDF, the advantages of keeping water volumes in the pond to a minimum were judged to outweigh the disadvantages. This continuing study lead to the addition of the tailings thickening step in the overall mine/mill process. In this step the tailings stream is thickened from approximately 10 to 50 percent solids by weight, thereby eliminating 90 percent of the water that would normally go to the pond with the tailings. In addition, since there is a net gain of precipitation over evaporation, a series of ponds with staged development and reclamation were planned to keep net water gain per pond to a minimum. Also, most importantly, underdrains were added to allow the tailings to drain as they were deposited.

The tailing deposition method that is now planned, and is described more fully in the above documents, includes a multi-point discharge of the thickened tailings into each pond. The tailings will establish a gently sloping beach (approximately 0.5 percent) to a ponded water area on the far side of the tailing pond. It is estimated the ponded water area will be approximately 20 percent of the tailing pond area.

Dust control and MWDF operation with respect to surface water ponding are addressed more fully in the attached papers, "Tailing Surface Dusting from Wind Erosion" (Attachment No. 2) and "Tailing Ponds Water Clarification Pools" (Attachment No. 3).

8. The amount of calcium oxide (lime) used in the mill process is estimated at 1.74 kg/t (4.2 pounds per short ton) of mill feed. This volume is split with additions at the mill, the tailings thickener, and the water reclaim ponds. The lime treatment will form metal hydroxides which will either be carried to the tailing ponds with the tailings stream or to the reclaim ponds with the thickener overflow stream. The metal hydroxides will precipitate and require some additional storage volume allowance. This additional volume allowance for the precipitates caused by the lime treatment is estimated at 100,000 m^3 (131,000 cubic yards) and is provided for in the capacity of the MWDF. As presented in the Feasibility Report (Section 3.1), this volume is assumed to develop in the reclaim ponds and then at the end of Project life it is transferred to the final tailing pond.

   MWDF capacity allowance is also provided for a carbonate precipitate that will be produced in the water treatment process. This sludge, with a total life of mine volume estimate of 250,000 m^3 (327,000 cubic yards), will be entered into the tailings stream where it will be pumped to the tailing pond for disposal. Additional information for disposal of this waste is also included in the Feasibility Report (Section 3.1).

9. Design details of the water reclaim ponds are included in the EIR and the Golder Report "System Development", previously provided to the DNR. Plan sheets included in the Feasibility Report also contain preliminary

material and construction specifications. Basic sizing requirements included an approximate two month retention time for the process water and additional allowances for storm and mine water in the event of an excess water discharge system shutdown. Reagent use in the mill process and decay rates are also discussed in the Feasibility Report (Section 3.4) and the EIR (Section 1.4.5.1).

10. The Feasibility Report presents the results of the study related to pond freeboard (see also Golder, 1982d as referenced in the Feasibility Report). Wind, wave height, and length related to fetch, and precipitation storage capacity are all reviewed and discussed. For each pond the freeboard provided is sufficient to accommodate the various volumes of water and/or wave heights and lengths anticipated from the design storms (100 year - 24 hour and PMP events).

11. Waste rock disposal is addressed in the Feasibility Report (Section 9.2). All waste rock is used in the construction of the MWDF as either embankment material or slope protection. In all cases, it is underlain by the seepage control system (liner and underdrain) utilized in the MWDF.

These responses address all of the comments provided by the department in their letter of November 23, 1983. We appreciate the department's extensive review of the "Siting Report..." and believe that these responses address the content and concerns of the comments. We anticipate continued discussions with the Bureau of Solid Waste Staff regarding the mine waste disposal facility. Should you have any questions, please contact me.

Very truly yours,

EXXON MINERALS COMPANY

B J Hansen

Barry J. Hansen
Technical Service Manager

BJH/CCS:ef

attachments

xc: Mr. T. C. McKnight

NCD-DNR

Attachment No. 1

CRANDON PROJECT

MINE WASTE DISPOSAL FACILITY

SYSTEM 41-114B

OPERATING ASPECTS AND CONTINGENCY PLANS

SEEPAGE CONTROL SYSTEM

Exxon Minerals Company

C. C. Schroeder

March 22, 1983

Revised April 21, 1983

Revised July 1, 1983

MINE WASTE DISPOSAL FACILITY

SYSTEM 41-114B

OPERATION ASPECTS AND CONTINGENCY PLANS

SEEPAGE CONTROL SYSTEM

INTRODUCTION

The proposed Crandon Project Mine Waste Disposal Facility (MWDF), designated as System 41-114B, utilizes a design incorporating a pond liner and tailings underdrain system to control pond seepage during pond operation. After the pond is filled with tailings, a reclamation cap consisting of a seal, overdrain, and soil cover layer is used to reclaim the pond. The pond bottom seepage control system is used for a relatively short period of time after pond closure to collect remaining water draining from the tailings. After the excess tailings water is removed, the bottom seepage control system operation is stopped and the underdrain system becomes nonfunctional. After a period of time the entire tailing pond seepage conditions reach a steady state, whereby a small portion of precipitation infiltrates the reclamation cap, passes through the tailings mass, and eventually passes through the pond bottom drain and liner layers.

The purpose of this report is to review the planned operation of the seepage control system, suggest and describe possible failure or reduced performance conditions, and present possible contingency measures which might be appropriate to overcome any such difficulties.

OPERATING CONDITIONS

Figures 1 and 2 depict a typical pond cross-section and an enlarged detail of the filter, drain layer, and bentonite modified soil liner which comprise the pond seepage control system during pond operation. Figure 3 presents an enlarged detail of the pond reclamation cap system which becomes the ultimate seepage control system for the pond. During operation, water draining from the tailings enters the drain layer and flows to the perforated pipe at the pond bottom perimeter. An underdrain discharge system, as shown in Figure 4, is located at three locations at the perimeter of each pond to remove water accumulating in the underdrain. After reclamation, the reclamation cap functions in much the same fashion to control ultimate pond seepage. Precipitation infiltrating the soil cover enters the drain layer and flows laterally to the MWDF perimeter where it will infiltrate outside of the tailings mass. Some fraction (less than 20 mm/y [0.8 inch per year]) will pass through the bentonite-soil reclamation seal and become the eventual pond steady-state seepage.

POTENTIAL SEEPAGE CONTROL SYSTEM FAILURES

While there is nothing revolutionary about the seepage control system in that it consists of elements with established performance histories, the integration of the elements into a total system is less well established. Consequently, the question of overall system performance is asked and the possibility of system failure is suggested.

The following sections present unlikely although possible failure modes, the conditions that might result, the system conditions that should prevent the failure, and then suggest remedial or contingency measures that could be employed to correct the difficulty.

- <u>Underdrain Choking</u> - Particle migration or some chemical reaction might cause a precipitate to form and choke the drain layer. The preliminary design of the underdrain system uses a 0.46 m (1.5 feet) drain layer of -51 mm to +0.42 mm (-2 + 0.017 inch) sand recovered from the till, covered by a 0.46 m (1.5 feet) filter layer of -102 mm (-4 inches) till. The highest water flow in the underdrain is at the inside edge of the pond at the location of the perforated drain pipe. The actual depth or thickness of underdrain required to handle this design water flow in the underdrain is less than 0.1 m (0.3 foot). This degree of conservatism requires that over 75 percent of the total underdrain layer must choke off before any of its necessary carrying capacity is reduced.

  The filter layer, which is designed to prevent any migration of particles into the drain, would also be effective for the considerations of chemical precipitation events. Presumably, if any precipitation was to occur from tailings, leachate, and/or filter material interactions, it would begin in the upper portion of the filter layer (since the filter and drain material come from the same soil) and proceed downward with the seepage. This presumed condition is shown in Figure 5. In this case the entire depth of filter layer (0.46 m [1.5 feet]) and over 75 percent of the total underdrain layer would have to be choked off with precipitates before the required hydraulic capacity of the underdrain was reduced. Also, before there would be reduction in water flow to the underdrain, the chemical precipitate would have to lower the filter or underdrain material permeabilities to at least that of the tailings. If chemical precipitation choking was greater than this, the altered filter or underdrain layer would then restrict leachate movement from the tailings. This would cause reduced water flow to the remaining underdrain thickness, but not increase in seepage from the facility. This condition would provide the effect of having a lined pond underlain by a drain and liner (i.e. a double liner).

In the worst of cases if the entire depth of the underdrain would choke, depending upon the permeability finally reached in the underdrain, seepage would occur through a doubled-lined pond with no underdrain.

With the monitoring planned for the MWDF (see Monitoring and Quaility Assurance Plan), any condition producing reduced leachate movement to the underdrain would probably be first noticed as a lesser volume of water pumped from the underdrain. With the entire underdrain layer choked there would be no underdrain water pumped, but an increase in seepage (assuming underdrain permeability did not reduce below that of the tailings) would be noted below the pond liner. If any condition of this sort would develop, sampling and testing of the filter and drain layers might be required to determine the extent of the problem. In the worst of conditions, if the underdrain was completely choked, the contingency eveluation for the pond might be to apply a seal layer at whatever depth the tailings were at and construct another seepage control system above the first depth of tailings in order to utilize the remaining pond depth.

The seal might again be a bentonite modified soil layer overlain by a drain layer. Presumably, a design or operating change would be evaluated and could be implemented to prevent a reoccurrence of the underdrain choking problem. Since the underdrain and liner would only be initially installed on the bottom and up the slope to the first bench (one-third or one-fourth of the pond depth), it would be most practical to install the overlying seepage control system at the first bench level. This possible contingency procedure is shown in Figure 6.

o Underdrain Collection Pipe Failure - If particle plugging or collapse of the perimeter collection pipe occurs, it may render a portion or all of the system useless. Again, as with the other elements of the seepage control system, the collection pipe design is based on well established principles. The collection pipe preliminary design has considered wall thickness to support cover loads, backfill material size and gradation based on pipe perforation size, and pipe material compatibility with the wastes and possible leachates.

There is also redundancy in the pumping discharge system that affects consideration of a failure in the collection pipe system. The collection pipe system is planned as a horizontal system with three discharge points located around the permieter. Since water flow can go either direction from any point in the system, it would take at least two separate failures located between the same two discharge points before any major length of collection pipe was eliminated from the system. This feature is illustrated in Figure 7.

If, however, there was substantial or total failure of the collection pipe, there are contingency measures available if the drain blanket is functioning. With the increased thickness of the drain blanket in the area of the collection pipe, it would be possible to install wells (working from the tailings) into the drain blanket and pump to evacuate the drain layer. Figure 8 depicts this contingency measure.

- <u>Bentonite Modified Soil Liner Failure</u> - If for some reason such as leachate incompatibility, breakdown in quality control, or some other unknown factor, the liner permeability was to increase to the estimated level of permeability of the tailings or greater, then seepage could approach the rate at which the tailings can drain.

  Increased seepage would first be noticed beneath the pond liner. Depending upon the extent of the failure area, a number of contingency measures could be employed. Figure 9 shows a grouting program, conducted from the tailings surface, which could be employed to reseal an area of the pond bottom. At the other extreme, a recapping of the tailings, as described above, could be employed if there was a complete area-wide liner failure. Also, depending upon the volume release and its evaluated effect in the ground water regime, ground water pumping could be employed to control ground water gradients and collect any seepage reaching the ground water system.

- <u>Reclamation Cap Failures</u> - Reclamation cap failures could occur for similar reasons described for the pond bottom seepage control system. Monitoring of the cap performance could be achieved through use of moisture content sensors located in and around the top seal. The cap system has been planned as a long-term permanent cover to the extent possible when working with trees and vegetative cover that has a life cycle. Over the very long term, a normal forest management effort would be appropriate to assure continuance of the planned vegetative cover.

In the shorter term, for reclamation completed during operation or for the period of 30 years after plant shutdown, contingency measures for cap failure would include repair or replacement of the cap as necessary. Depending upon the nature or severity of the failure, corrections with varying degrees of effort could be employed; however, the ability to rather easily completely recap a pond or portion of a pond with an overlay offers a fail-safe ultimate correction step.

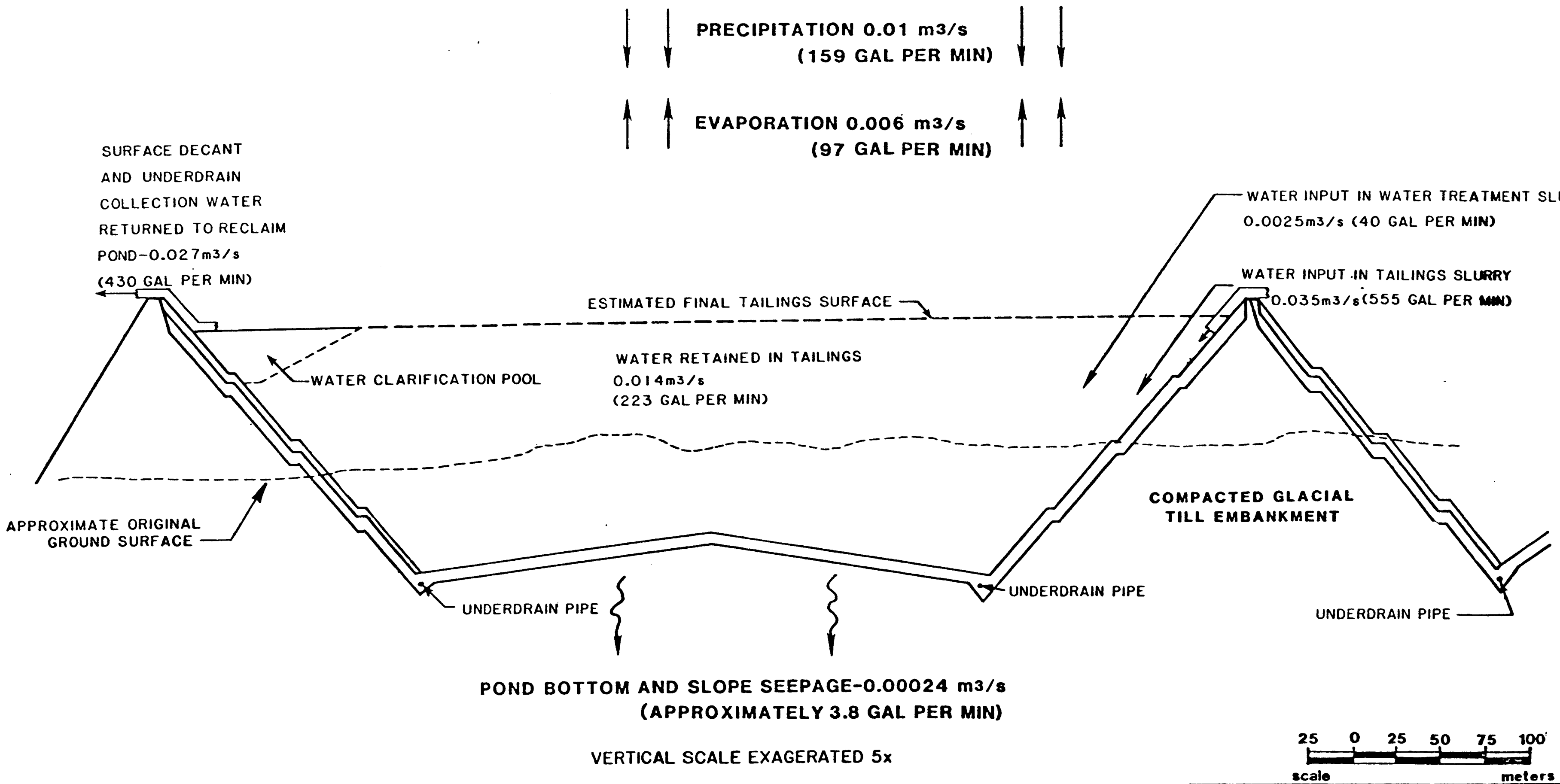
SUMMARY

The seepage control systems (liner, underdrain and reclamation cap) of the proposed MWDF are the critical components of the total waste disposal system in assuring compliance with ground water quality standards. Thoroughness in testing, design, construction, and operation monitoring is essential to assure that effective seepage control systems are provided and operate properly. Although the planning of the systems assures their effectiveness, failure modes or scenarios can be hypothesized and studied to allow consideration of the development of appropriate contingency plans.

Various hypothetical failure modes for the different components of the seepage control systems have been discussed and some of the available or possible contingency measures that prevent impacts from the failures have also been presented.

Again, as was noted in the introduction, the pond bottom seepage control system serves its purpose only during pond operation and for a few years after reclamation; thereafter, it is the reclamation cap that provides the final and continuing seepage control from the pond.

TYPICAL POND WATER BALANCE DURING OPERATION
(COMPUTATIONS BASED ON POND T3 AREA WITH AVERAGE PRECIPITATION)



NOTE:

2) PRECIPATATION 0.78m/YEAR
(30.77 IN PER YEAR)

3) EVAPORATION 0.59m/YEAR
(22.36 IN PER YEAR)
OVER 80% OF POND AREA

EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE
WASTE DISPOSAL FACILITY TYPICAL TAILINGS POND WATER BALANCE

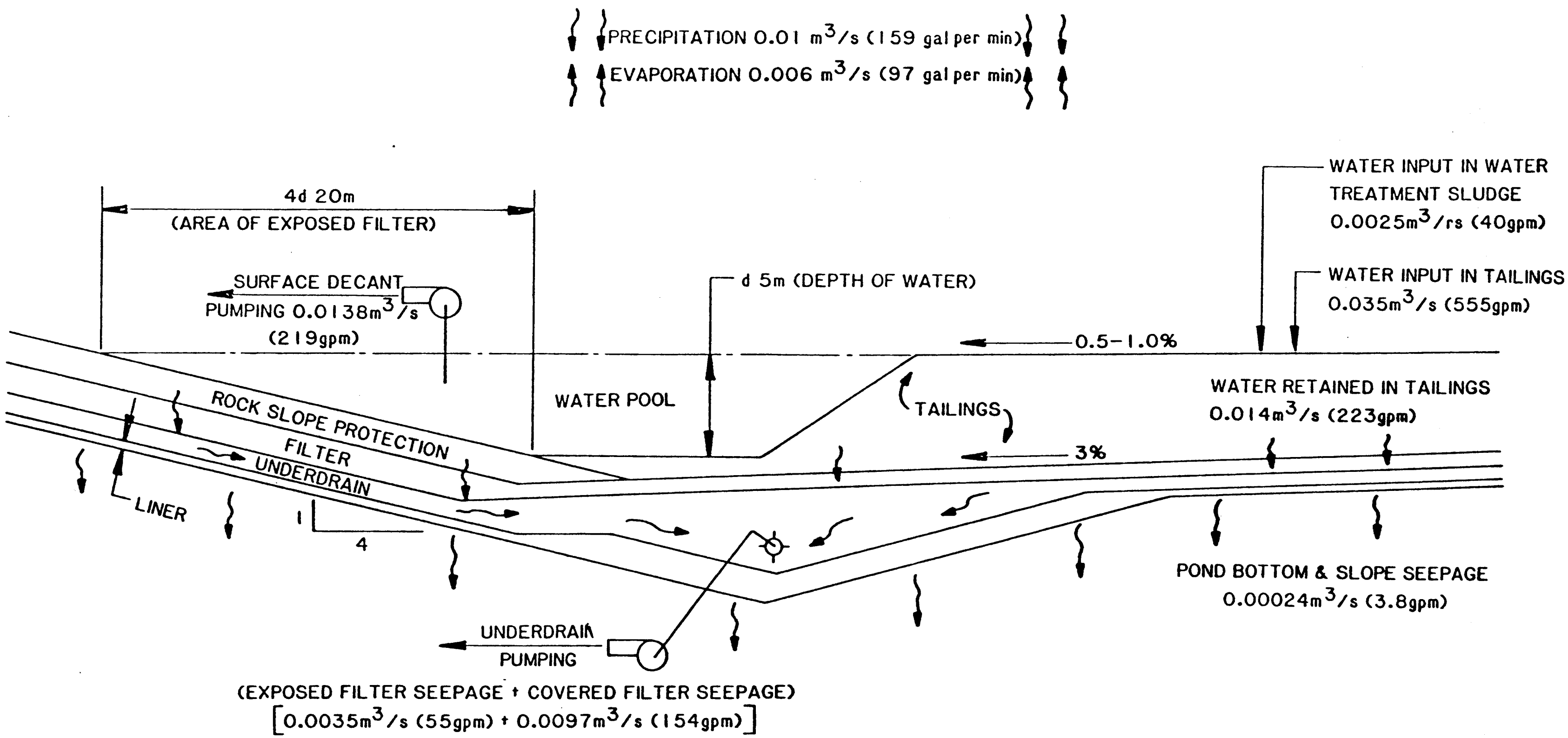
SCALE AS SHOWN | STATE WISCONSIN | COUNTY FOREST

DRAWN BY J.P. BECKER | DATE 8/82 | CHECKED BY C.C. Schroeder | DATE 5-11-83

APPROVED BY | DATE | APPROVED BY C.E. Fowler | DATE 10/26/92

APPROVED BY | DATE | EXXON | DATE

DRAWING NO FIGURE 1 | SHEET 1 OF 1 | REVISION NO 0



NOTES:

1) Typical pond water balance maintains
Q Decant + Q Underdrain = Q Tails + Q Sludge + Q Prec. −
Q Evap. − Q Seepage − Q Retained

2) Typical pond water balance during operation based on pond T3 area.

3) Precipitation 0.78 m/y (30.77 inches per year).

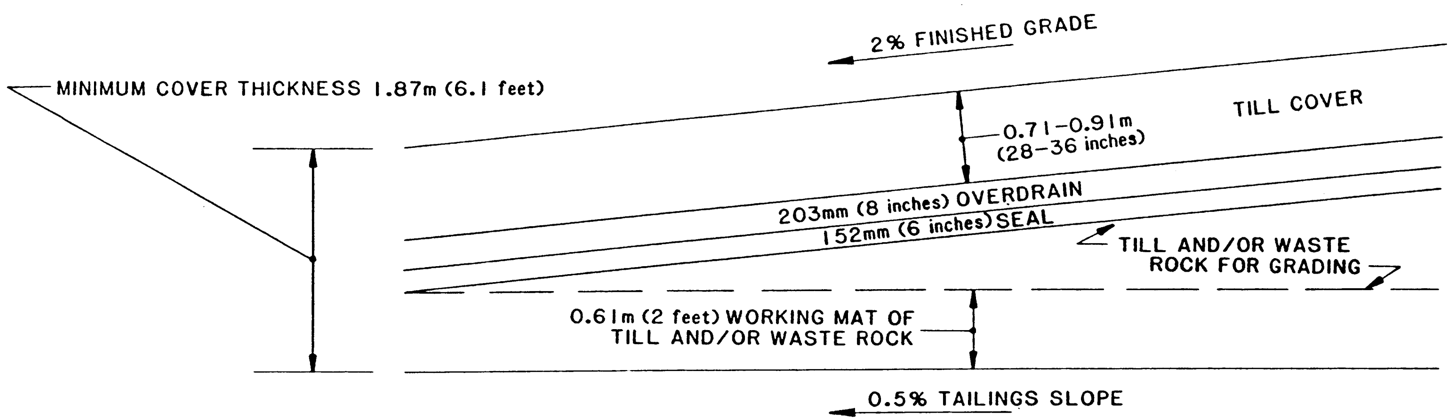
4) Evaporation 0.59 m/y (22.56 inches per year).
Over 80 percent of pond area

5) Conditions shown at point in time when pond bottom has just
been covered with tailings.

EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE
TYPICAL POND
POOLED WATER CONDITION

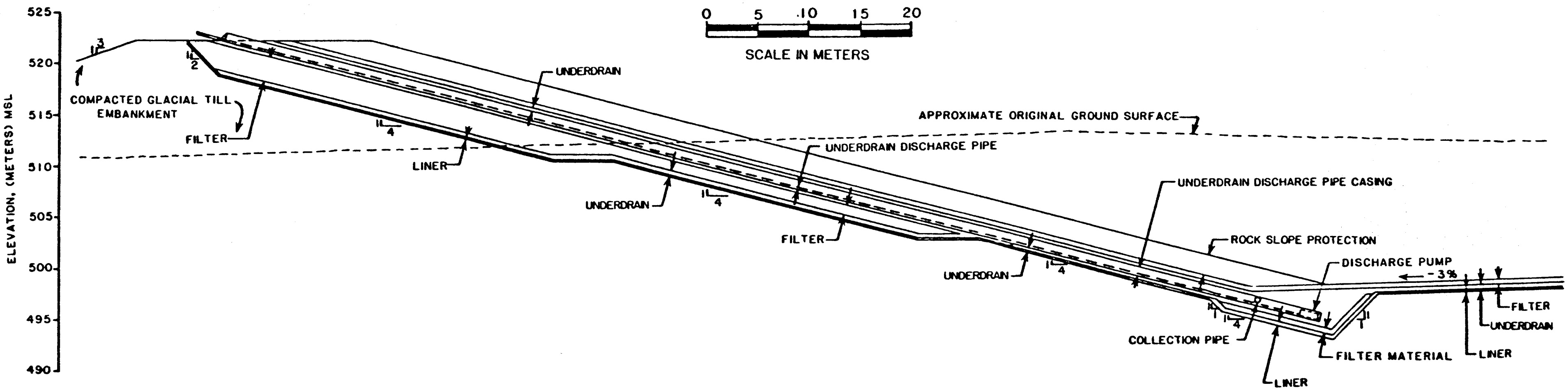
SCALE NONE	STATE WISCONSIN	COUNTY FOREST	
DRAWN BY	DATE 3/21/83	CHECKED BY	DATE
APPROVED BY	DATE	APPROVED BY	DATE
APPROVED BY	DATE	EXXON	DATE
DRAWING NO FIGURE 2		SHEET ____ OF ____	REVISION NO



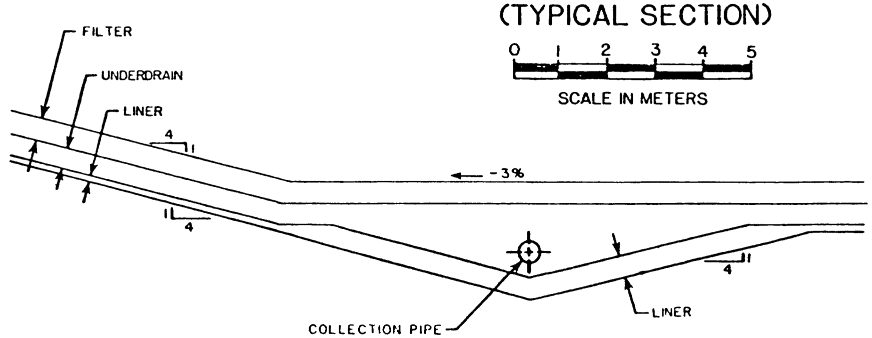
SEAL TO BE MADE OF BENTONITE MODIFIED SOIL
OVERDRAIN CONSISTS OF COARSE GRAVEL

EXXON MINERALS COMPANY CRANDON PROJECT				
TITLE **RECOMMENDED COVER SYSTEM FOR TAILINGS PONDS**				
SCALE NONE	STATE WISCONSIN		COUNTY FOREST	
DRAWN BY S. J. Harvey	DATE 9/8/82	CHECKED BY C. Schroeder		DATE 10/82
APPROVED BY	DATE	APPROVED BY C. E. Fowler		DATE 9/23/82
APPROVED BY	DATE	EXXON		DATE
DRAWING NO **FIGURE 3**		SHEET 1 OF 1		REVISION NO 0

UNDERDRAIN DISCHARGE PIPE
(TYPICAL SECTION)



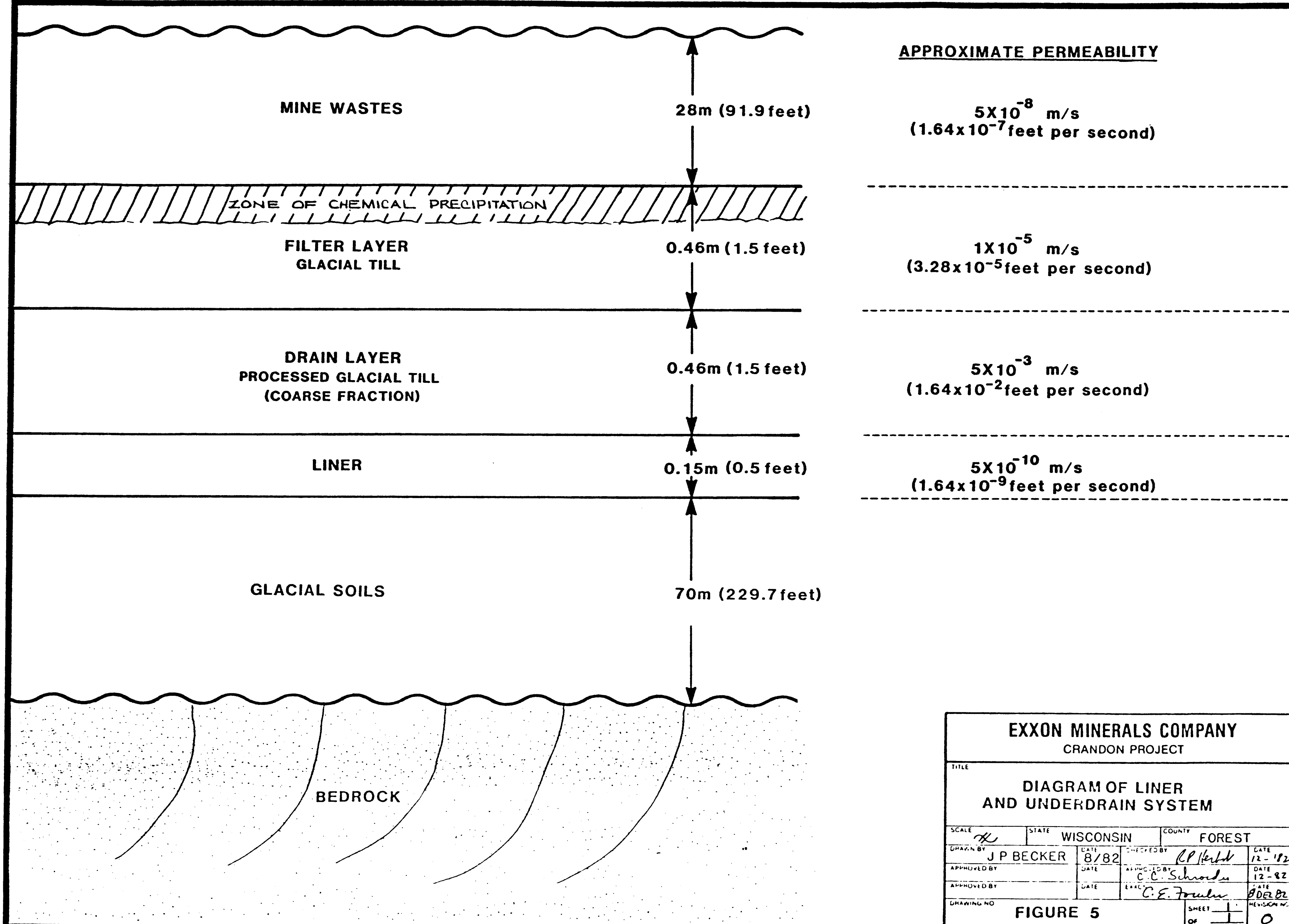
UNDERDRAIN POND PERIMETER PIPE
(TYPICAL SECTION)



EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE
WASTE DISPOSAL FACILITY SEEPAGE CONTROL SYSTEM

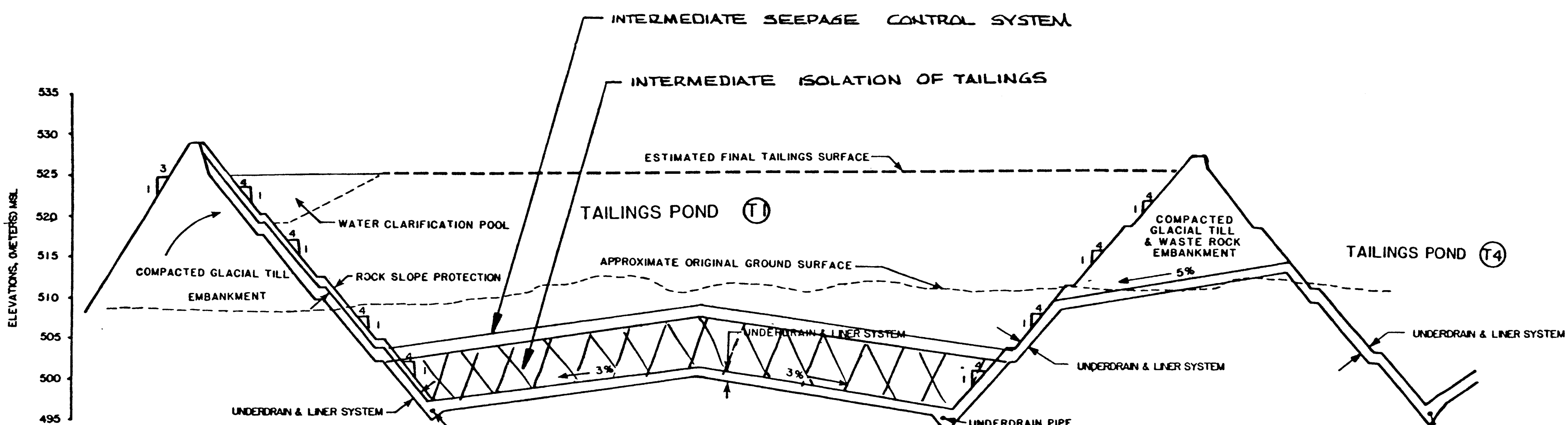
SCALE AS SHOWN	STATE WISCONSIN	COUNTY FOREST
DRAWN BY D.R. SPRINGBORN	DATE 7/82	CHECKED BY
APPROVED BY	DATE	APPROVED BY
APPROVED BY	DATE	EXXON
DRAWING NO FIGURE 4	SHEET 1 OF 1	REVISION NO 0



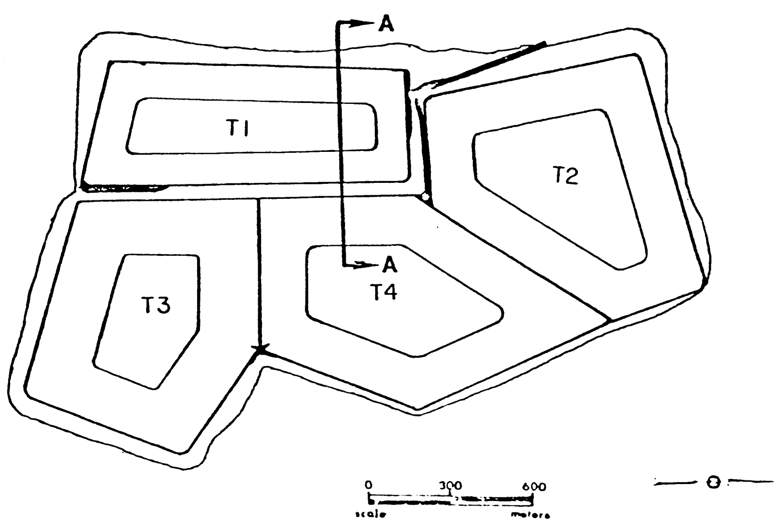
EXXON MINERALS COMPANY
CRANDON PROJECT

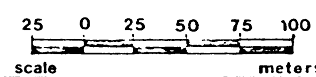
TITLE: DIAGRAM OF LINER AND UNDERDRAIN SYSTEM

SCALE: NONE	STATE: WISCONSIN	COUNTY: FOREST	
DRAWN BY: J P BECKER	DATE: 8/82	CHECKED BY: CP Herbst	DATE: 12-'82
APPROVED BY	DATE	APPROVED BY: C. C. Schroeder	DATE: 12-82
APPROVED BY	DATE	EXEC: C. E. Fowler	DATE: 8 DEC 82
DRAWING NO: FIGURE 5		SHEET 1 OF 1	REVISION NO: 0



SECTION A-A
VERTICAL SCALE EXAGGERATED 5x



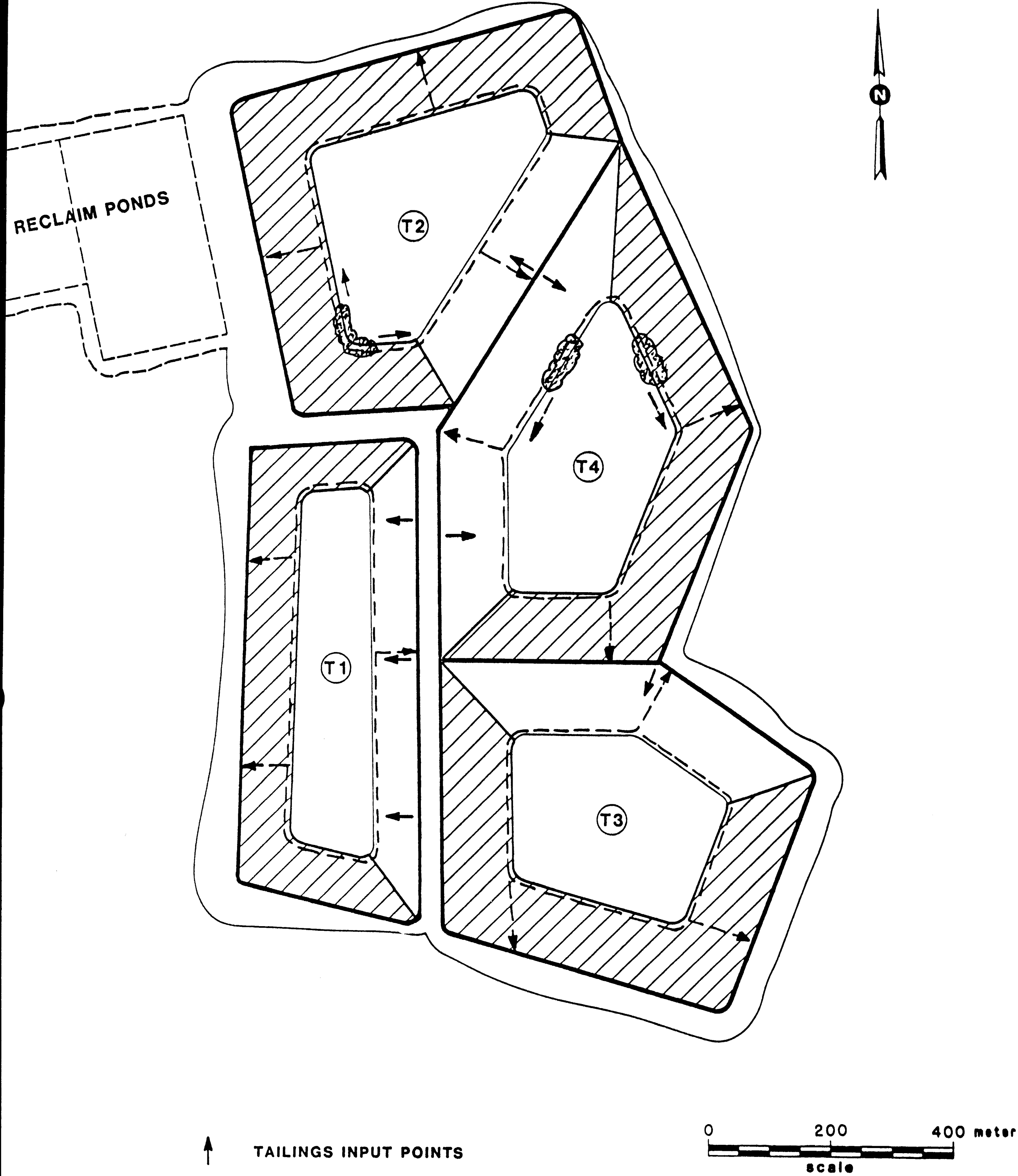


EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE

WASTE DISPOSAL FACILITY
POND SECTION

SCALE AS SHOWN	STATE WISCONSIN		COUNTY FOREST		
DRAWN BY J P BECKER	DATE 8/82	CHECKED BY [illegible signature]		DATE 8-17-82	
APPROVED BY	DATE	APPROVED BY [illegible signature]		DATE [illegible] /82	
APPROVED BY	DATE	EXXON		DATE	
DRAWING NO FIGURE 6			SHEET 1 OF 1		REVISION NO. 0



↑ TAILINGS INPUT POINTS

ROCK FACING FOR SLOPE PROTECTION

UNDERDRAIN COLLECTOR

UNDERDRAIN DISCHARGE

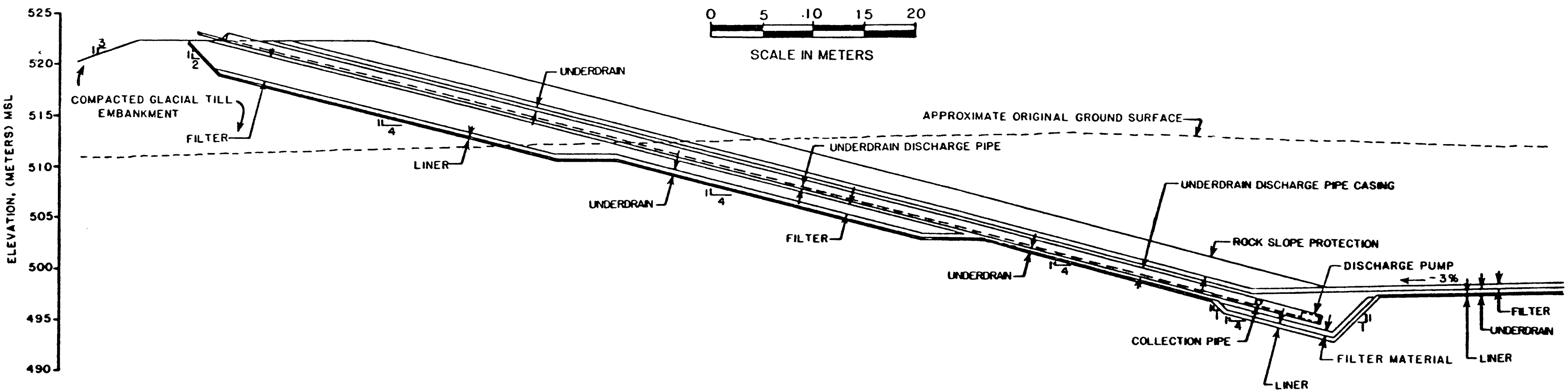
PIPE FAILURES

EXXON MINERALS COMPANY

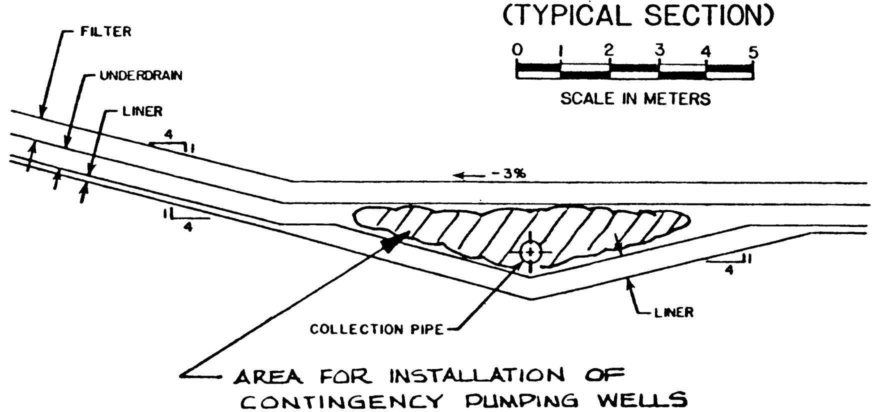
CRANDON PROJECT

TITLE	**WASTE DISPOSAL FACILITY TAILINGS PONDS DEPOSITION POINTS**		
SCALE AS SHOWN	STATE WISCONSIN	COUNTY FOREST	
DRAWN BY R.C. DIETZ	DATE 7/82	CHECKED BY C.C. Schroeder	DATE 8.17.82
APPROVED BY	DATE	APPROVED BY C E Fowler	DATE 9/26/82
APPROVED BY	DATE	EXXON	DATE
DRAWING NO **FIGURE 7**		SHEET 1 OF 1	REVISION NO 0

UNDERDRAIN DISCHARGE PIPE
(TYPICAL SECTION)



UNDERDRAIN POND PERIMETER PIPE
(TYPICAL SECTION)



EXXON MINERALS COMPANY CRANDON PROJECT			
TITLE: WASTE DISPOSAL FACILITY SEEPAGE CONTROL SYSTEM			
SCALE: AS SHOWN	STATE: WISCONSIN	COUNTY: FOREST	
DRAWN BY: D.R. SPRINGBORN	DATE: 7/82	CHECKED BY: C.C. Schroeder	DATE: 9-17-82
APPROVED BY	DATE	APPROVED BY: C.E. Fowler	DATE: 9/20/82
APPROVED BY	DATE	EXXON	DATE
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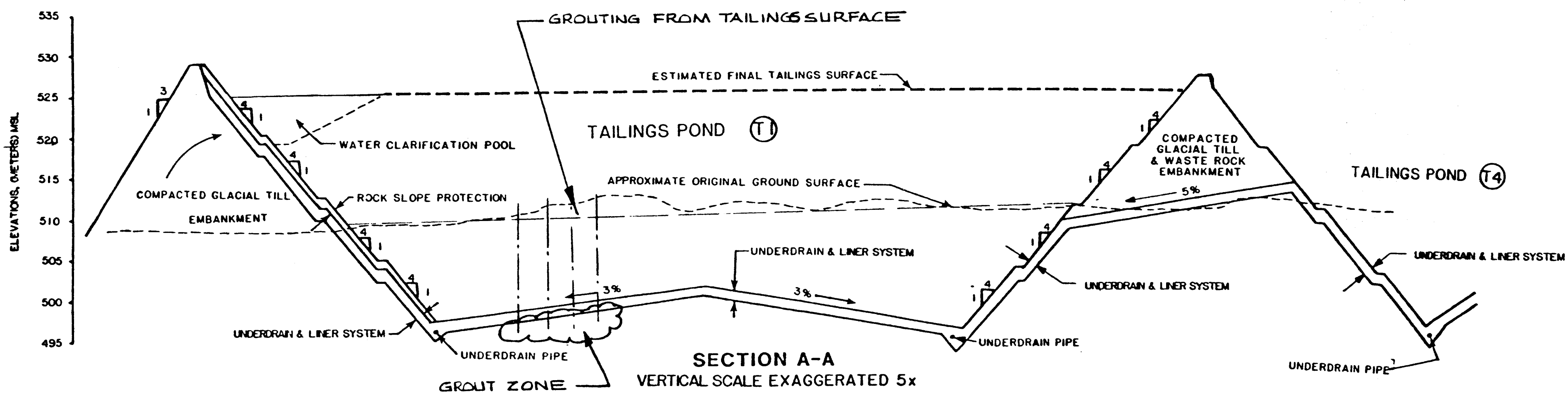
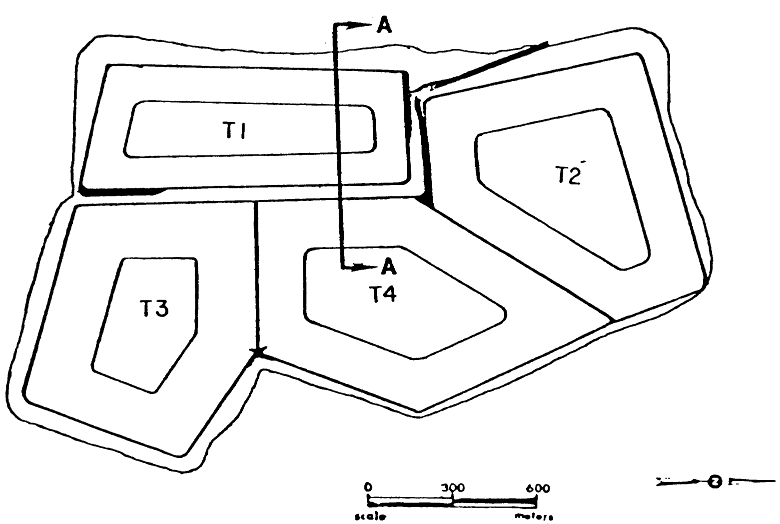


SECTION A-A
VERTICAL SCALE EXAGGERATED 5x



25 0 25 50 75 100
scale meters

EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE
WASTE DISPOSAL FACILITY
POND SECTION

SCALE AS SHOWN	STATE WISCONSIN	COUNTY FOREST	
DRAWN BY J P BECKER	DATE 8/82	CHECKED BY C.C. Schroeder	DATE 8-17-82
APPROVED BY	DATE	APPROVED BY C.E. Fowler	DATE 10-2-82
APPROVED BY	DATE	EXXON	DATE
DRAWING NO FIGURE 9		SHEET 1 OF 1	REVISION NO 0

Attachment No. 2

CRANDON PROJECT

MINE WASTE DISPOSAL FACILITY

SYSTEM 41-114B

TAILINGS SURFACE DUSTING FROM WIND EROSION

Exxon Minerals Company

C. C. Schroeder

February 8, 1983

MINE WASTE DISPOSAL FACILITY

SYSTEM 41-114B

TAILINGS SURFACE DUSTING FROM WIND EROSION

Tailing Pond Description and Operation

The proposed mine waste disposal facility (MWDF) consists of four similarly sized tailing ponds that will be sequentially constructed, operated, and reclaimed over the approximate 28 year Project life. The pond bottoms will be incised to provide fill for the surrounding pond embankments. The inside embankment slopes will be 1 on 4 and pond depths will be approximately 30 m. The tailings are completely enclosed by the surrounding embankments which are to be full earthen construction. Vegetation is to be established on the outside 1 on 3 slopes of the pond embankments as soon as possible after embankment placement.

Over the course of each pond's use (6-8 years) the exposed tailings surface area will increase from approximately 14 ha (bottom pond area) to 40 ha (pond area inside the crest). A tailings distribution system has been planned to allow discharge of thickened tailings from multiple locations around the pond perimeters. It is expected tailing beaches with slopes in the range of 0.5-1.0 percent will develop throughout the pond. Water will be removed from the pond through a surface decant system and via the pond underdrain system.

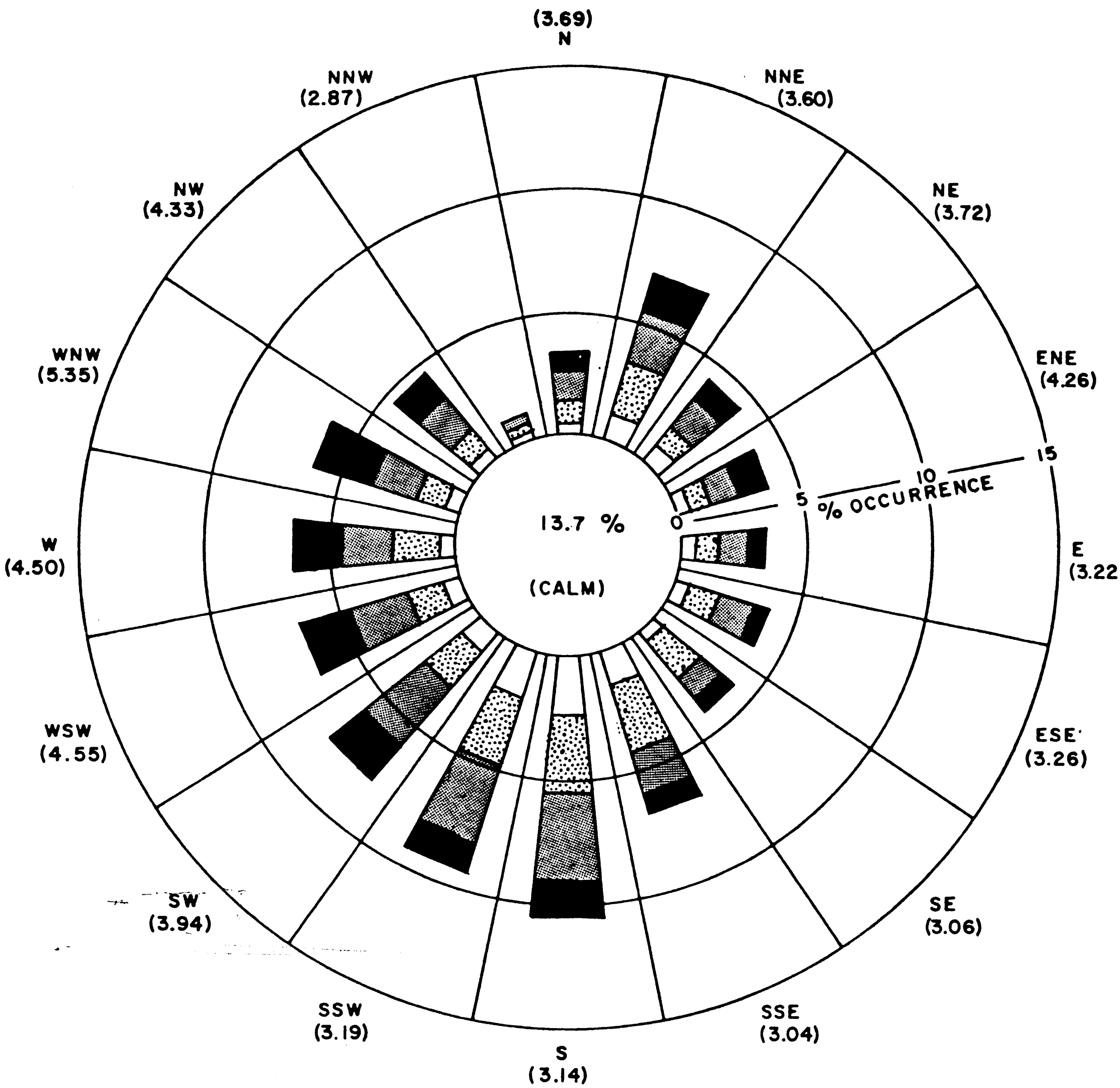
Potential Tailings Surface Dusting Problems

The action of the wind on the exposed tailings area has potential to cause dusting in the Project area. Wind currents can lift tailings particles and transport the particles considerable distances through the air. These particles can be a nuisance as airborne dust and as settled dust which then has the potential to affect natural systems (Reference 1).

The mechanics of the tailings particle transport are related to airspeed, air currents, particle diameter, and particle specific gravity. Based on experience with tailings similar to the anticipated Crandon Project tailings and for areas with similar meteorological conditions, there is potential for tailings dusting from wind erosion.

Figure 1 and Tables 1 and 2 present wind, temperature, and precipitation data applicable to the site area (Reference 2). Based on these data and with experience from other operating facilities, if there was no provision for its control there could be wind erosion and dusting of tailings for brief periods from May through November. Precipitation is greatest through these months, which acts to eliminate much of the tailings dusting; however, evaporation rates are also high and surface drying times are fast. Normal precipitation, temperature, and ground conditions will eliminate any potential for tailings dusting through the late fall, winter, and early spring periods. Mean temperatures below freezing and frozen ground conditions usually occur from December through March and there is also usually snowcover throughout this period.

Since the full earthen embankments will be vegetated on the outside, potential tailings wind erosion is restricted to only the tailings surface area inside the pond. Also, the potential for wind erosion should be at a minimum during



LEGEND:

(0.00) MEAN WIND SPEED (m/s) FOR SECTOR

WIND SPEED (m/s)

> 5.0

3.0 - 5.0

1.5 - 3.0

0.0 - 1.5

MEAN WIND SPEED FOR
ALL SECTORS: 3.24 m/s

EXXON MINERALS COMPANY
CRANDON PROJECT

ENVIRONMENTAL STUDY AREA WIND ROSE
JANUARY-DECEMBER, 1978
STATION 1

DAMES & MOORE

FIGURE 1

TABLE 1

LONG-TERM AVERAGE TEMPERATURES (°C) AT NICOLET COLLEGE, RHINELANDER, WISCONSIN AND WAUSAU MUNICIPAL AIRPORT, WAUSAU, WISCONSIN

	NICOLET COLLEGE (1908-1980)[a]			WAUSAU MUNICIPAL AIRPORT (1973-1977)[b]				
MONTH	MEAN DAILY MAXIMUM	MEAN DAILY MINIMUM	MONTHLY MEAN	MEAN DAILY MAXIMUM	MEAN DAILY MINIMUM	MONTHLY MEAN	HIGHEST	LOWEST
Jan.	- 6.1	-17.2	-11.7	- 6.0	-16.7	-11.3	11.1	-31.7
Feb.	- 3.3	-15.6	- 9.4	- 1.5	-12.7	- 7.1	12.2	-31.7
Mar.	2.8	- 9.4	- 3.3	4.1	- 5.8	- 0.8	18.3	-23.3
Apr.	11.1	- 0.6	5.3	12.6	0.9	6.8	28.3	-14.4
May	18.3	6.1	12.2	19.8	7.2	13.5	31.1	- 2.8
Jun.	23.9	11.1	17.5	24.5	12.0	18.3	32.8	1.7
Jul.	24.4	12.2	18.3	26.1	14.6	22.0	36.1	7.2
Aug.	25.0	12.8	18.9	25.7	13.6	19.7	36.1	4.4
Sep.	19.4	7.8	13.6	19.7	8.3	14.0	34.4	- 2.2
Oct.	14.4	3.9	8.9	14.4	3.0	8.7	32.8	- 8.9
Nov.	4.4	- 3.9	0.3	4.6	- 4.3	0.2	21.7	-23.9
Dec.	- 3.6	-12.8	- 8.0	- 3.8	-13.0	- 8.3	10.0	-27.8

[a]Black, 1981.

[b]NOAA, 1973-1977b.

TABLE 2

LONG-TERM AVERAGE PRECIPITATION TOTALS (mm) AT NICOLET COLLEGE, RHINELANDER, WISCONSIN AND WAUSAU MUNICIPAL AIRPORT, WAUSAU, WISCONSIN

MONTH	NICOLET COLLEGE (1908-1980)[a]	WAUSAU MUNICIPAL AIRPORT (1973-1977)[b]
Jan.	26.8	20.9
Feb.	24.9	24.1
Mar.	37.5	76.0
Apr.	58.8	90.1
May	84.2	94.8
Jun.	114.7	71.8
Jul.	97.8	73.2
Aug.	104.0	87.0
Sep.	95.0	67.5
Oct.	59.0	37.7
Nov.	46.8	53.2
Dec.	27.2	38.5
Annual Total	776.7	734.8

[a]Black, 1981.

[b]NOAA, 1973-1977b.

the first few years of operation because the tailings surface area is small and the full height of the surrounding embankments will offer wind protection. Wind erosion will increase to its full potential as the tailings surface approaches the pond crest.

The overall potential for wind erosion of the tailings is primarily minimized by the staged construction, operation, and reclamation of the mine waste disposal facility thereby keeping a reduced area of tailings exposed. Early reclamation, consisting of a vegetated earthen cap, is the most positive way of eliminating the potential for tailings wind erosion and dusting. Although final reclamation eliminates the potential for dusting, during operation of the pond other interim dust control measures will be utilized.

<u>Proposed Interim Dust Control Measures</u>

Tailing pond reclamation methods, for both final reclamation or interim temporary reclamation, are generally classified in three categories:

1) Physical - covering with soil or other restraining material and also including moisture control.

2) Chemical - addition of an interaction material to form a crust.

3) Vegetative - establishment of vegetative cover.

Sometimes, combinations of methods such as chemical-vegetative or physical-vegetative treatments prove most effective (Reference 3).

The final Crandon Project reclamation method, after a tailing pond has been filled and removed from service, is a physical method. An impervious seal, drainage layer, and soil cover with vegetation is used to provide permanent long-term isolation of tailings. However, as noted above because of the potential for tailings wind erosion during operation, interim measures, to be applied as required, must also be capable of controlling tailings wind erosion. In the case of interim measures, they must not degrade the waste management facility or its operation, or be prohibitively expensive. The same basic methods used for permanent tailings erosion control can be utilized for interim control of dusting, including moisture control, developing a surface crust, and vegetating the tailings surface.

Moisture Control - An effective method of eliminating potential tailings dusting is by maintaining a moist tailings surface. Moist conditions will prevail in the areas covered by the tailings discharge and pooled water in the pond. With the proposed tailings discharge system, it is expected that operating procedures can be employed to take maximum advantage of moisture control through tailings discharge. This might involve periodic discharge at alternating locations in the pond or divided discharge at multiple pond locations.

If necessary, to either cover some portions of the tailings surface area, or in the event tailings discharge is interrupted, the surface decant and underdrain water removal systems can be used for wetting the tailings surface. Instead of pumping removed water to the reclaim ponds it would be recycled through the tailing ponds. Either the tailings lines (if they are shut down), separate discharge lines, or separate spray systems could be employed for this method. The necessary additional system equipment would be minimal since the network of pond perimeter pipes and the pumps are already planned for the surface decant and underdrain systems. Although not expected to be necessary, water could also be returned from the reclaim ponds for this purpose. This method also offers the prospect of improved overall system water balance through loss of water by evaporation.

Surface Crusting - The development of a surface crust on the tailings, whereby the tailings particles are held in a coherent layer with the aid of a binder (either naturally occurring or as an additive), may also be employed to prevent wind erosion of the tailings. There is evidence that a crust may normally develop on the tailings surface through the oxidation of the iron-bearing sulfides in the tailings. When this occurs, the resulting oxides act as a binder to the tailings, resulting in a coherent layer or crust of oxide and tailing (Reference 4).

Binding of the tailing surface particles can also be accomplished through addition of chemicals or other materials. Lignosulfonate products, a paper mill waste product, have been used as dust control agents. Basically, these products are the cementing agents in the wood materials. Typically, they are sold as a concentrated solution and then diluted at the time of application. Normally, they are sprayed on a surface but they could also be entered into a tailing stream as a final tailings layer is being deposited (Reference 5).

A wide range of other chemicals, including petroleum-based products, resin emulsions, cements, bituminous-based products, and organic polymers, have also been shown to be effective in stablizing fine tailings surfaces. The chemical treatments are generally not as durable as the physical treatments; however, they are good for use in active ponds and can be evaluated and selected to be compatible with the mill processes and with a range of tailings properties (Reference 3).

Tailings Surface Vegetation - For areas that will be inactive for substantial periods of time, the use of grass and herb cover development directly on tailings is suitable and effective (Reference 6). Adjustment of pH with limestone and fertilization are usually necessary; however, grasses can be established rapidly depending upon time of planting. This is even true for highly acidic tailings. Excellent growth of grasses has been observed on copper tailings with pH's as low as 3.1 (Reference 7). In many cases either a physical (normally a mulch) or chemical method is employed with the vegetation to provide further protection of the seedlings. Adequate study of vegetative type reclamation methods is recommended before a full scale reclamation program is initiated. However, these types of studies have indicated direct reclamation on sulfide tailings is possible, and is becoming an established procedure in Canada (Reference 8). There is less availability of longer term results and they are less predictable, and continued pH maintenance and fertilization sometimes has been required; however, for the Crandon Project this type of vegetative cover would only be used as an interim dust control measure prior to installation of the permanent cap.

Conclusion

During the Project operating period, the action of the wind on the exposed tailing area in the MWDF has potential to cause dusting in the Project area. However, there is ample evidence that tailings dusting can be controlled by a variety of methods including moisture control, chemical binders, and vegetation. It would be imprudent to formulate a specific interim dust control plan without some actual operating experience with the proposed MWDF. However, the general approach will be to start with the most cost-effective method and proceed from there as necessary. For the Crandon Project this would include:

- Utilization of natural surface crusting through oxidation of the tailings.
- Moisture control of the surface by recycling decant and underdrain water over the tailings.
- Creation of a surface crust on the tailings through addition of a chemical binder.
- Vegetation of the tailings surface.

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1) Hawley, John R. 1977. The Problem of Acid Mine Drainage in the Province of Ontario. Publication, Ministry of the Environment, Ontario, pp. 170-174.

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3) Dean, K. C., R. Havens, M. W. Glantz. 1974. Methods and Costs for Stabilizing Fine-Sized Mineral Wastes. RI 7896, Bureau of Mines Report of Investigations.

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5) Flambeau Paper Corporation. "Flambinder for Dust Control and Road Stabilization." Publication.

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Attachment No. 3

CRANDON PROJECT

MINE WASTE DISPOSAL FACILITY

SYSTEM 41-114B

TAILING PONDS WATER CLARIFICATION POOLS

Exxon Minerals Company

C. C. Schroeder

February 8, 1983, Rev. 0

March 22, 1983, Rev. 1

MINE WASTE DISPOSAL FACILITY

SYSTEM 41-114B

TAILINGS PONDS WATER CLARIFICATION POOLS

INTRODUCTION

Presented in this paper is an analysis of the potential for water to pool in the tailing ponds. Because of the underdrain system design which is continuous across the pond bottom and up the side slopes, there may be too much exposed filter and underdrain for water to pool in the ponds. Golder Associates, based on their knowledge and experience, believes there will be water pooling in the ponds; however, their preliminary engineering work did not attempt to analyze or quantify these conditions.

SYSTEM DESIGN AND OPERATION

Each of the four tailing ponds in the Crandon Project mine waste disposal facility (system 41-114B) is similarily designed according to the typical cross section shown in Figure 1. The details of the liner, underdrain, and filter system that cover the bottom and inside faces of the embankments for all ponds are shown in larger scale in Figure 2.

While the bottom section is identical for all ponds there are minor differences in the side slope cross sections, including:

1. A layer of rock slope protection is included on the sides where ponded water is anticipated, whereas on the tailings input side(s) the rock is omitted.

2. The filter layer is thickened on the ponded water sides (in tailing pond T1 since there is a surplus of waste rock available at the time of its construction, the waste rock layer is thickened and the filter layer thickness is not changed).

Each of the ponds has two or three benches along the side slope length to allow vertical staging of the construction of the liner and underdrain and filter system if desired.

The purpose of the liner, underdrain, and filter system is to reduce seepage from the tailing ponds to minimal levels. This system is required over the pond bottom and the pond sides, which by the time the pond is filled, have substantially more area exposed to the tailings than the pond bottom. The underdrain conducts seepage to a perimeter pipe system at a low point on the inside embankment toe where it is removed from the pond. With the underdrain functioning only a negligible depth of water is maintained on the liner and seepage through the liner is greatly reduced. The filter layer between the tailings and the underdrain prevents any migration of tailings into the underdrain layer.

In the operation of the MWDF, thickened tailings are discharged on one or two sides of the tailing ponds where it is anticipated beaches with slopes in the range of 0.5 to 1.0 percent will develop. With tailings input at the locations shown, the estimated final tailings surface is shown in Figure 3.

Based on Golder Associates' experience, they suggest a water pool will develop in the tailing ponds. They expect the pooled water area would be approximately 20 percent of the pond area and the water pool would remain at about a 6.1 m (20 foot) depth. They further suggest that the bottom of the pooled water area would be essentially horizontal except for the area at the waters edge which would have an approximate 10 percent slope. In estimating these conditions, Golder Associates has reviewed tailing ponds that they consider to be similar to the proposed MWDF (system 41-114B). While the ponds do not employ similar underdrains, they are typically high leak rate facilities that would behave like the proposed system.

DEVELOPMENT OF WATER CLARIFICATION POOL

Because of the extent of exposed filter and underdrain, there would be no chance of any water pooling when a tailing pond is first put in use, until at least the pond bottom is covered with tailings. Based on average tails production this would require 2-3 months. However, after the bottom is covered with tailings, the area of exposed underdrain and filter is greatly reduced. In this situation, the filter layer will act to restrain seepage from the system and the typical condition for a tailing pond will be similar to Figure 4.

The figure shows the relationship between an assumed depth of ponded water and the slope length exposed for seepage. On a total area exposed basis, taking the typical length of the potential ponded water area around the embankment face to be about 500 m, the total seepage area is approximately 2,000 d (with the pooled water depth d in meters).

Following calculations presented in the appendix, using a Q = KiA relationship with average head on the filter being d/2 and Q taken from the anticipated pond water balance, a depth of water can be determined based on the permeability of the filter layer. With the above method of analysis the following K, d, and surface decant pumping relationship is obtained:

K of Filter	d of Pooled Water	Rate of Surface Decant Pumping
1×10^{-6} m/s	3.3 m (11 feet)	0
5×10^{-7} m/s	5.0 m (16.4 feet)	0
1×10^{-7} m/s	5.0 m (16.4 feet)	0.014 m^3/s (219 gpm)
5×10^{-8} m/s	5.0 m (16.4 feet)	0.016 m^3/s (247 gpm)

The pooled water analysis shows that the permeability of the filter must be about 1×10^{-6} m/s (3.3×10^{-6} feet per second) before any significant ponded water depth would develop. Also, the permeability would have to be below 5×10^{-7} m/s (1.64×10^{-7} feet per second) before an approximate 5.0 m (16.4 feet) depth of water would develop. Lower permeability values would result in greater ponding depth or would require decant pumping to maintain an approximate 5.0 m (16.4 feet) water pool depth.

The analysis indicates that ponded water development will be predictable and depend upon the filter permeability. The majority of the till materials, which are planned to be used for the filter, are estimated to have a permeability of less than 2×10^{-7} m/s when placed and compacted with normal efforts. In addition, there are other simple options available to assure that desired permeabilities are achieved such as special compactive effort or use of waste fines from underdrain material processing as a filter blend.

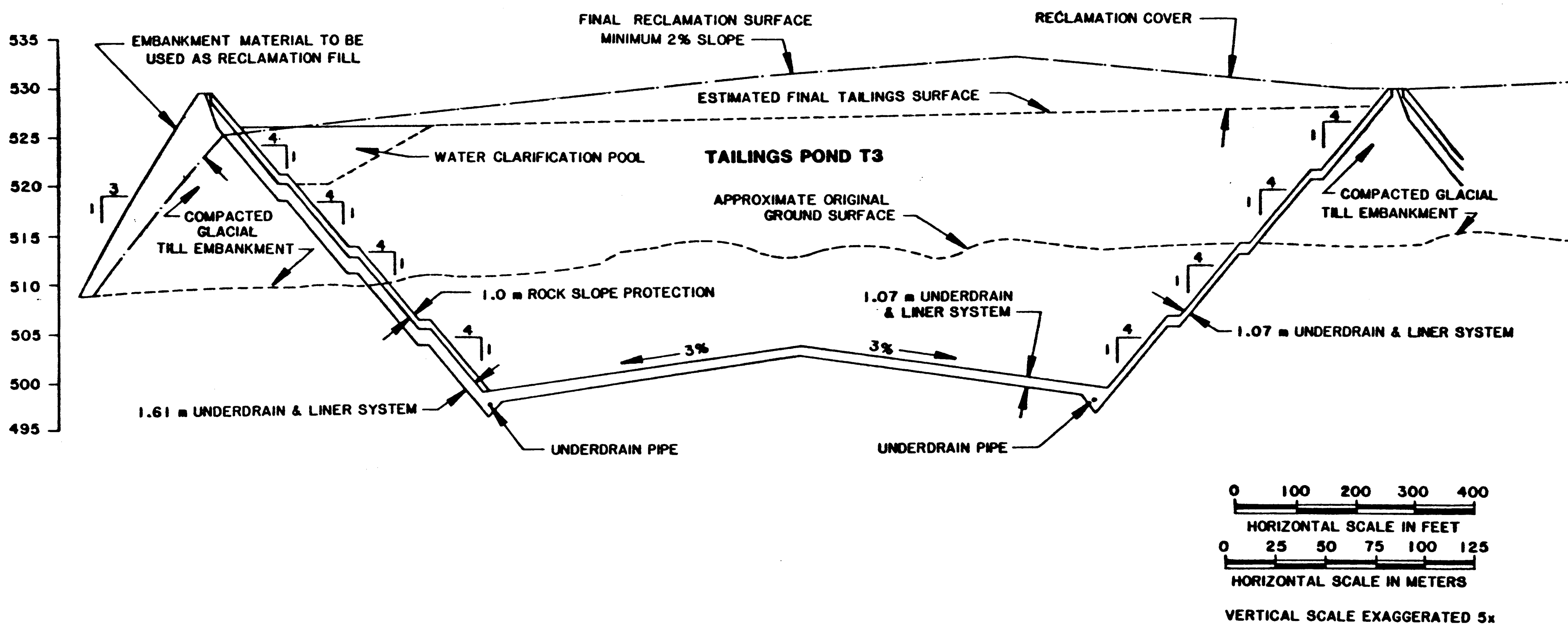
Once in operation, the system itself would probably be somewhat self adjusting as far as permeability is concerned. Areas of the filter that do seep faster because of higher permeabilities would likely experience some surface choking from any of the finest tailings fraction still suspended in the decant water.

Finally, there is also opportunity to reduce the lateral extent of the exposed seepage area by movement of the tailings discharge lines around the pond perimeter. Thus the 500 m length used in the analysis can be field adjusted. Any reduction of exposed area by these means would also increase ponded water depth.

OPERATING FLEXIBILITY

While the above analysis does indicate that pooled water conditions will develop in the tailing ponds, the operation of the waste disposal facility is not dependent on maintaining a pool of water in the tailing pond. While normally a pooled water area would be maintained in the tailing pond for water clarification, the filter layer will perform the same function in the proposed MWDF. With the rather limited water volumes entering the tailing pond, because of the thickened tailings, both the surface water decant pumping system and the underdrain pumping system can be sized to easily handle the entire tailing water volume with little size penalty in the equipment.

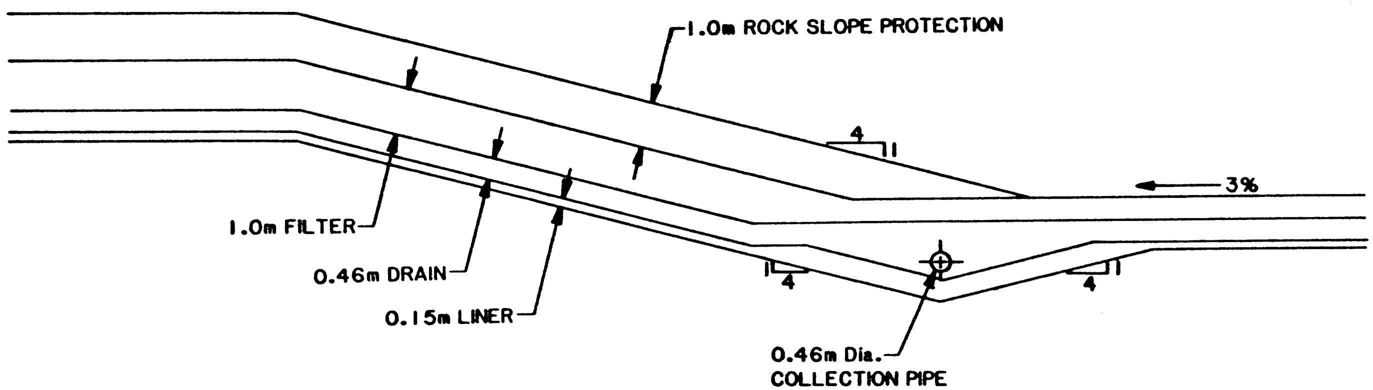
Regardless of tailing water decant requirements, a decant system for storm water removal would be included in the MWDF. Detailed requirements for the system based on storm water handling capacities have not been developed, but if storm water volumes such as the probable maximum precipitation (PMP) event have to be removed from the pond in a two or three week period, they will govern the sizing of the decant system.



EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE
TYPICAL TAILINGS POND CROSS SECTION

SCALE AS SHOWN	STATE WISCONSIN	COUNTY FOREST	
DRAWN BY S. J. HARVEY	DATE 1/83	CHECKED BY	DATE
APPROVED BY	DATE	APPROVED BY	DATE
APPROVED BY	DATE	EXXON	DATE
DRAWING NO **FIGURE NO. 1**	SHEET ___ OF ___	REVISION NO	



0 1 2 3 4 5 6

SCALE IN METERS

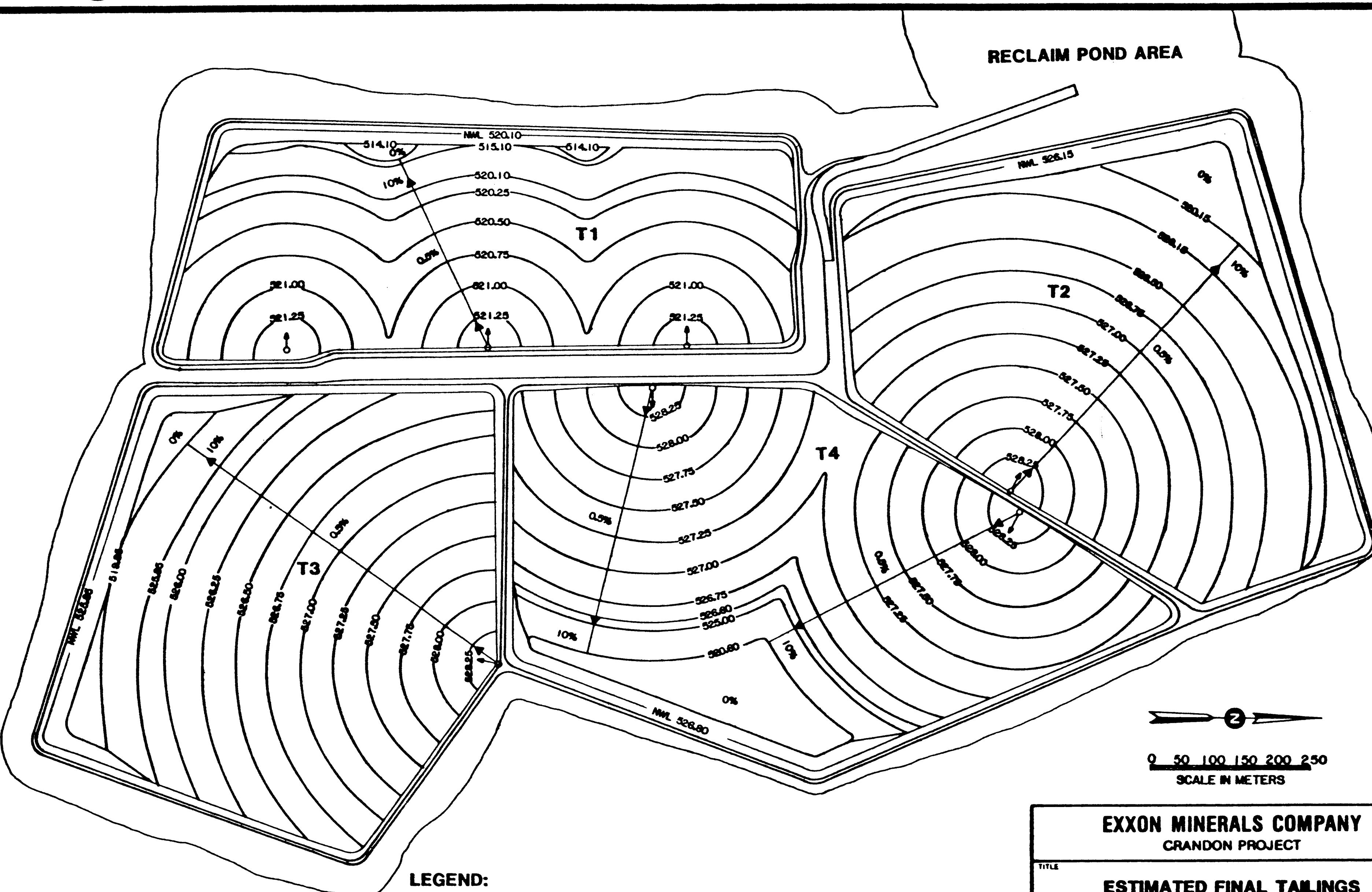
EXXON MINERALS COMPANY

CRANDON PROJECT

TITLE

LINER, UNDERDRAIN, & FILTER DETAIL

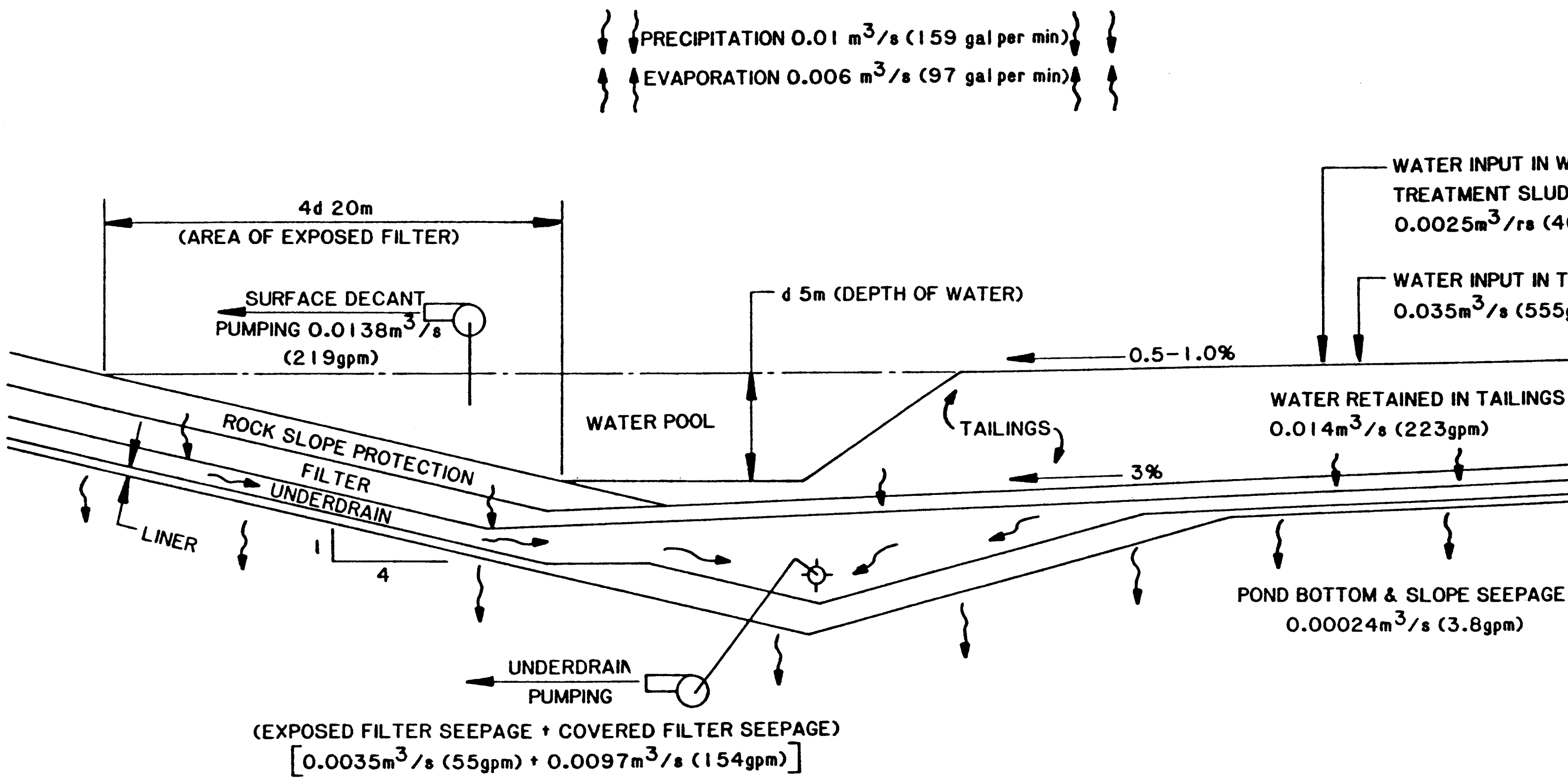
SCALE SHOWN	STATE WISCONSIN	COUNTY FOREST	
DRAWN BY DR SPRINGBORN	DATE 1/83	CHECKED BY	DATE
APPROVED BY	DATE	APPROVED BY	DATE
APPROVED BY	DATE	EXXON	DATE
DRAWING NO **FIGURE NO. 2**	SHEET ____ OF ____	REVISION NO	



LEGEND:

- TAILINGS INPUT POINT
- 0% TAILINGS SURFACE SLOPE
- — NWL — NORMAL FULL POND WATER LEVEL

EXXON MINERALS COMPANY CRANDON PROJECT					
TITLE **ESTIMATED FINAL TAILINGS SURFACE**					
SCALE SHOWN	STATE WISCONSIN		COUNTY FOREST		
DRAWN BY DR SPRINGBORN	DATE 1/83		CHECKED BY		DATE
APPROVED BY	DATE		APPROVED BY		DATE
APPROVED BY	DATE		EXXON		DATE
DRAWING NO **FIGURE NO. 3**			SHEET ___ OF ___		REVISION NO



NOTES:

1) Typical pond water balance maintains
Q Decant + Q Underdrain = Q Tails + Q Sludge + Q Prec. -
Q Evap. - Q Seepage - Q Retained

2) Typical pond water balance during operation based on pond T3 area.

3) Precipitation 0.78 m/y (30.77 inches per year).

4) Evaporation 0.59 m/y (22.56 inches per year).
Over 80 percent of pond area

5) Conditions shown at point in time when pond bottom has just been covered with tailings.

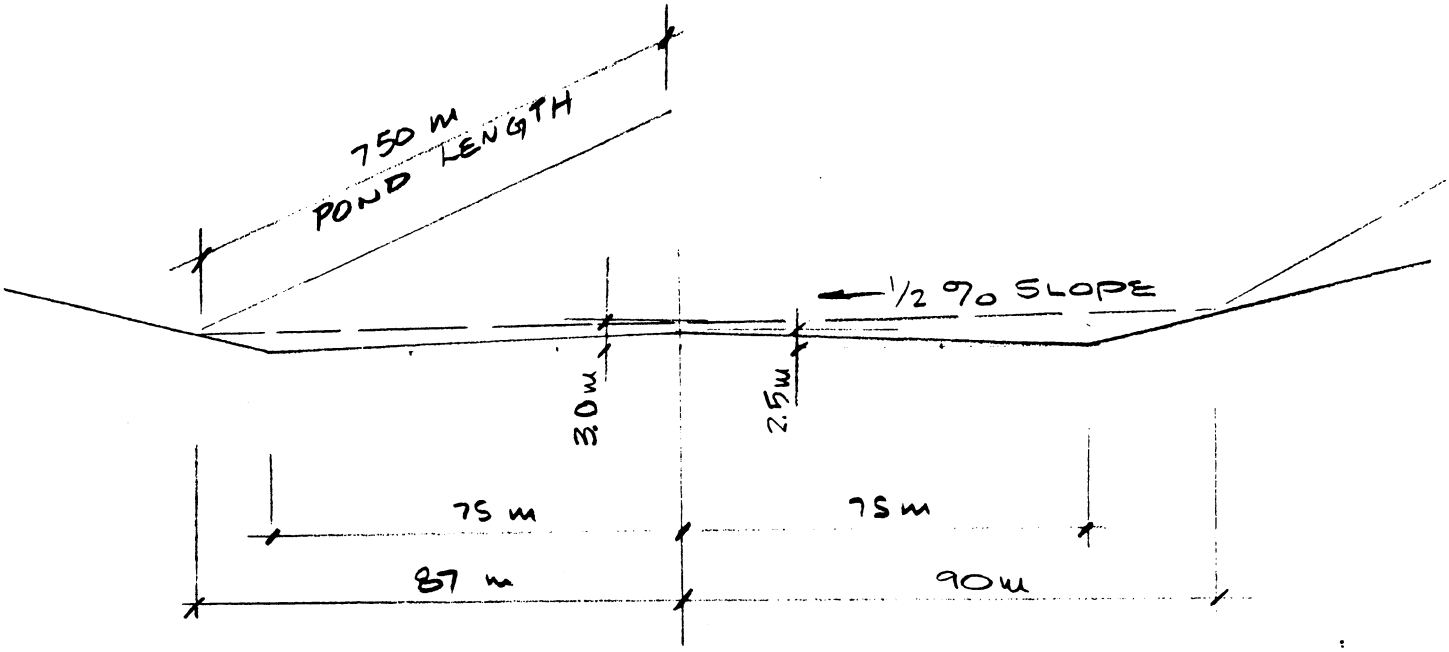
EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE
TYPICAL POND
POOLED WATER CONDITION

SCALE NONE	STATE WISCONSIN		COUNTY FOREST		
DRAWN BY	DATE 3/21/83	CHECKED BY		DATE	
APPROVED BY	DATE	APPROVED BY		DATE	
APPROVED BY	DATE	EXXON		DATE	
DRAWING NO FIGURE 4			SHEET ___ OF ___		REVISION NO

TAILS POND WATER POOLING C. Schroeder 3-21-82

DETERMINE TIME TO COVER POND BOTTOM WITH TAILS



END AREA = 177 × 0.5 + 1/2 × 87 × 2.5 + 1/2 × 90 × 2.5

END AREA = 310 m^2

APPROX. VOL. = 310 m^2 × 750 m = 232,300 m^3

= 389,530 t

at 4300 t/d of tailings ~ 90 days

DETERMINE DEPTH OF POOLED WATER IN TAILINGS PON[D]

1) FROM TYPICAL POND WATER BALANCE (SEE ATTACHED FIGURE 1.4-18) DETERMINE POTENTIAL QUANTITY OF WATER AVAILABLE FOR SURFACE POOLING

   a. AVERAGE SURFACE DECANT AND UNDERDRAIN COLLECTION WATER RETURNED TO RECLAIM POND is 0.027 m^3/s (430 gal. per min.)

   b. PORTION SEEPING THROUGH TAILINGS VARIES AS PONDS ARE FILLED. $Q = KiA$, WITH $K = 5 \times 10^{-8}$ m/s (1.6×10^{-7} ft. per sec.), $i = 1$, and A varying from 0 to the inside pond crest area. At the POINT IN TIME WHEN THE BOTTOM OF THE POND IS JUST COVERED (USING POND T3 AS THE TYPICAL POND) Q THROUGH THE TAILINGS IS:

$$Q = K i A$$

where A = 12.92 ha (31.9 acs.)

$$Q = 5 \times 10^{-8} \times 1 \times 12.92 \times 10000$$

$$Q = 0.006 \ m^3/s$$ (102 gal per min.)

WHEN THE POND IS FILLED A has INCREASED TO 40.29 ha (99.5 acs.) and Q is:

$$Q = 5 \times 10^{-8} \times 1 \times 40.29 \times 10000$$

$$Q = 0.020 \ m^3/s$$ (319 gal. per min.)

c. determine TOTAL BOTTOM SEEPAGE ACCORDING to above figure where:

- 90% of bottom area has tailings seeping at unit gradient
- 10% of bottom area has tailings seeping at $i = 6$ $\left(i = \frac{5+1}{1} \right)$

Then Q = bottom Seepage = KiA

$$= 5\times10^{-8} \times 1 \times 12.92 \times 10000 \times 90\%$$

$$+ 5\times10^{-8} \times 6 \times 12.92 \times 10000 \times 10\%$$

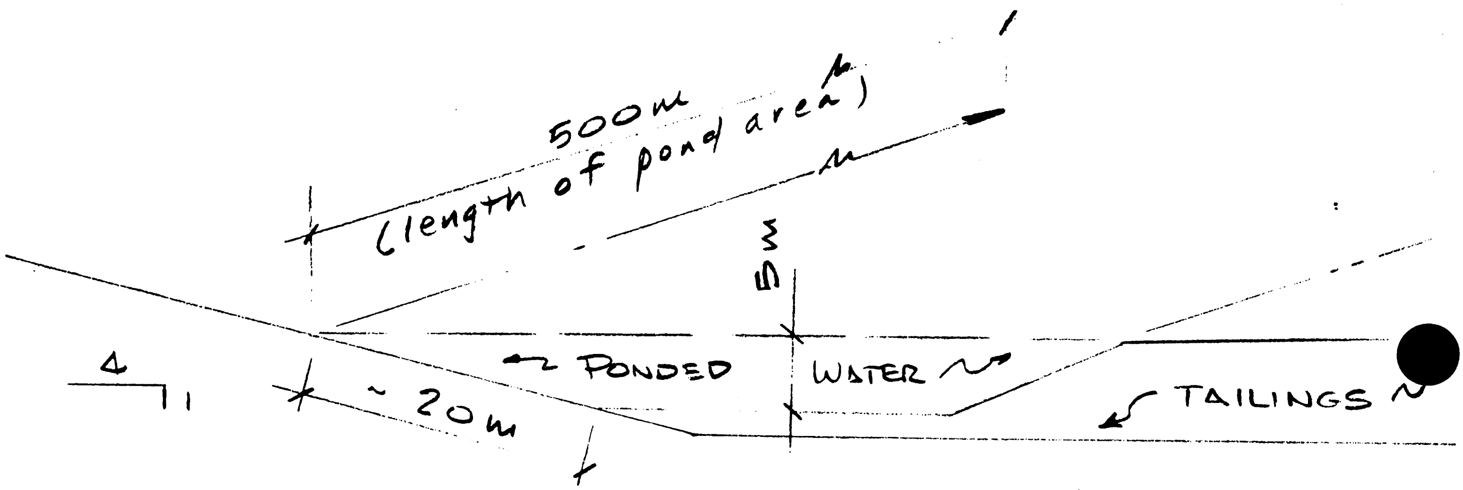
$$Q = 0.00969 \text{ m}^3/\text{s} \quad (154 \text{ gpm})$$

Then WATER AVAILABLE FOR POOLING = Q_{POOL}

$$Q_{POOL} = 0.027 - 0.00969 = 0.0173 \text{ m}^3/\text{s} \quad (274 \text{ gpm})$$

2. DETERMINE FLOW THROUGH EXPOSED FILTER AREA FOR DIFFERENT PERMEABILITIES. ASSUME THE FOLLOWING :

- CONFIGURATION ACCORDING TO SKETCH BELOW
- LENGTH OF EXPOSED FILTER = 500 m
- 5 m Ponded Water Depth



AREA (EXPOSED FILTER) = 20 m × 500 m
= 10000 m^2

i (EXPOSED FILTER) = (AVG. HEAD + LINER) / LINER
= (5/2 + 1) / 1
= 3.5

a. <u>WITH K = 1×10^{-6}</u>

Q = K i A

= $1 \times 10^{-6} \times 3.5 \times 10000$

$Q = 0.035\ m^3/s$ (too great - water won't pool to 5 m depth with $k = 1\times10^{-6}\ m/s$

determine depth with $k = 1\times10^{-6}$

then Exposed AREA $= 4 \times d \times 500$
$= 2000\ d$

Avg. seepage gradient $= (d/2 + 1)/1$

then : $Q = kiA$

$$0.0173 = 1\times10^{-6} \times \left[(d/2+1)/1\right] \times 2000d$$

$$8.65 = d^2/2 + d$$

$$d = 3.3$$

b. with $k = 5\times10^{-7}$

$$Q = 5\times10^{-7} \times 3.5 \times 10000$$

$Q = 0.0175\ m^3/s$ (277 gpm) (just about equal to water available for pooling; nothing to decant)

c. with $k = 1\times10^{-7}$

$$Q = 1\times10^{-7} \times 3.5 \times 10000$$

$Q = 0.0035\ m^3/s$ (55 gpm)

decant water $= 0.0173 - 0.0035$

$= 0.0138\ m^3/s$ (219 gpm)

d. with $K = 5 \times 10^{-8}$

$$Q = 5 \times 10^{-8} \times 3.5 \times 10000$$

$$Q = 0.00175 \ m^3/s \ (28 \ gpm)$$

decant Water $= 0.0173 - 0.00175$

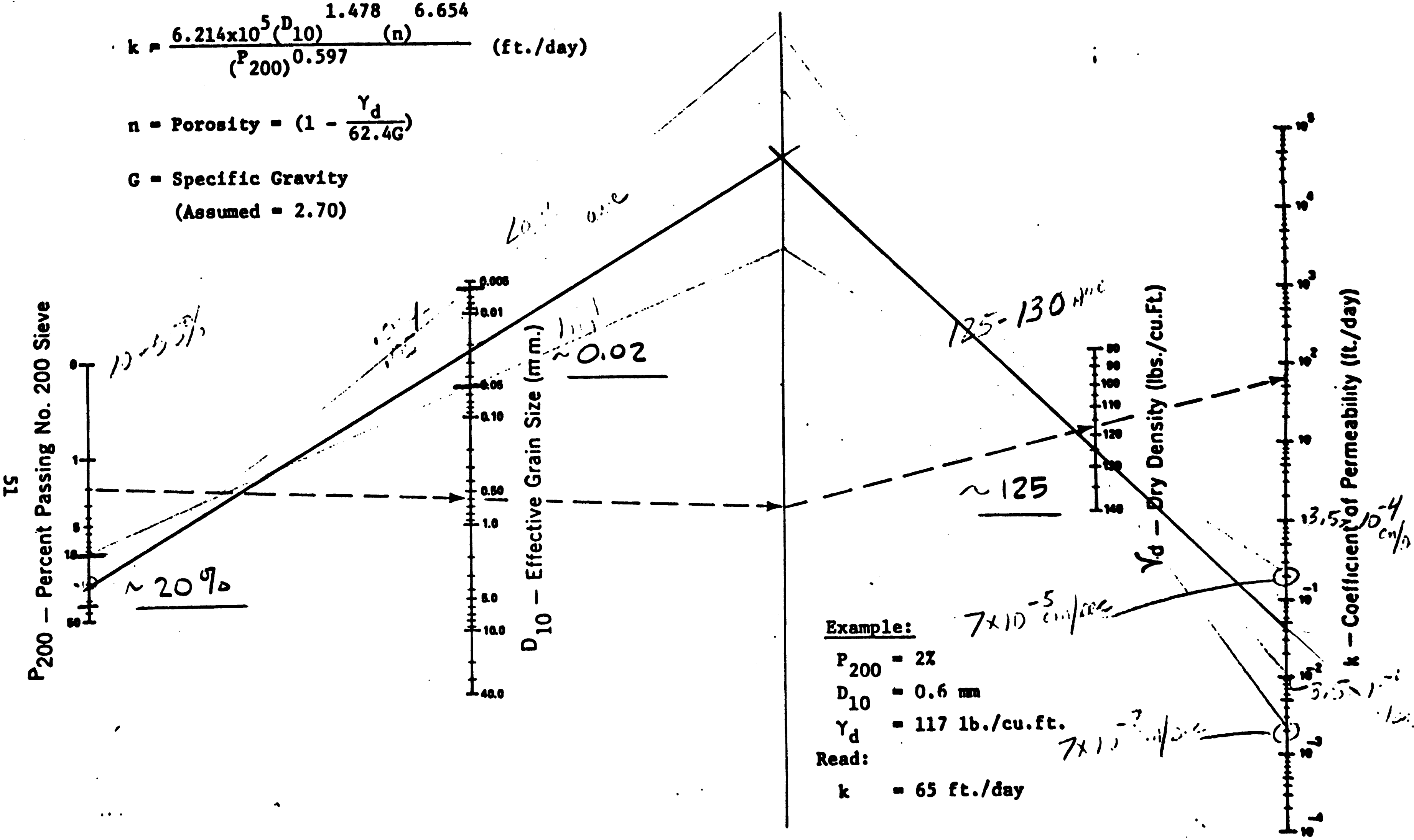
$$= 0.0156 \ m^3/s \ (247 \ gpm)$$

APPENDIX

$$k = \frac{6.214 \times 10^{5} (D_{10})^{1.478} (n)^{6.654}}{(P_{200})^{0.597}} \quad \text{(ft./day)}$$

$$n = \text{Porosity} = \left(1 - \frac{\gamma_d}{62.4G}\right)$$

G = Specific Gravity
(Assumed = 2.70)



Example:

P_{200} = 2%
D_{10} = 0.6 mm
γ_d = 117 lb./cu.ft.
Read:
k = 65 ft./day

Figure 28. Chart For Estimating Coefficient of Permeability of Granular Drainage and Filter Materials

K = 0.04 ft/day

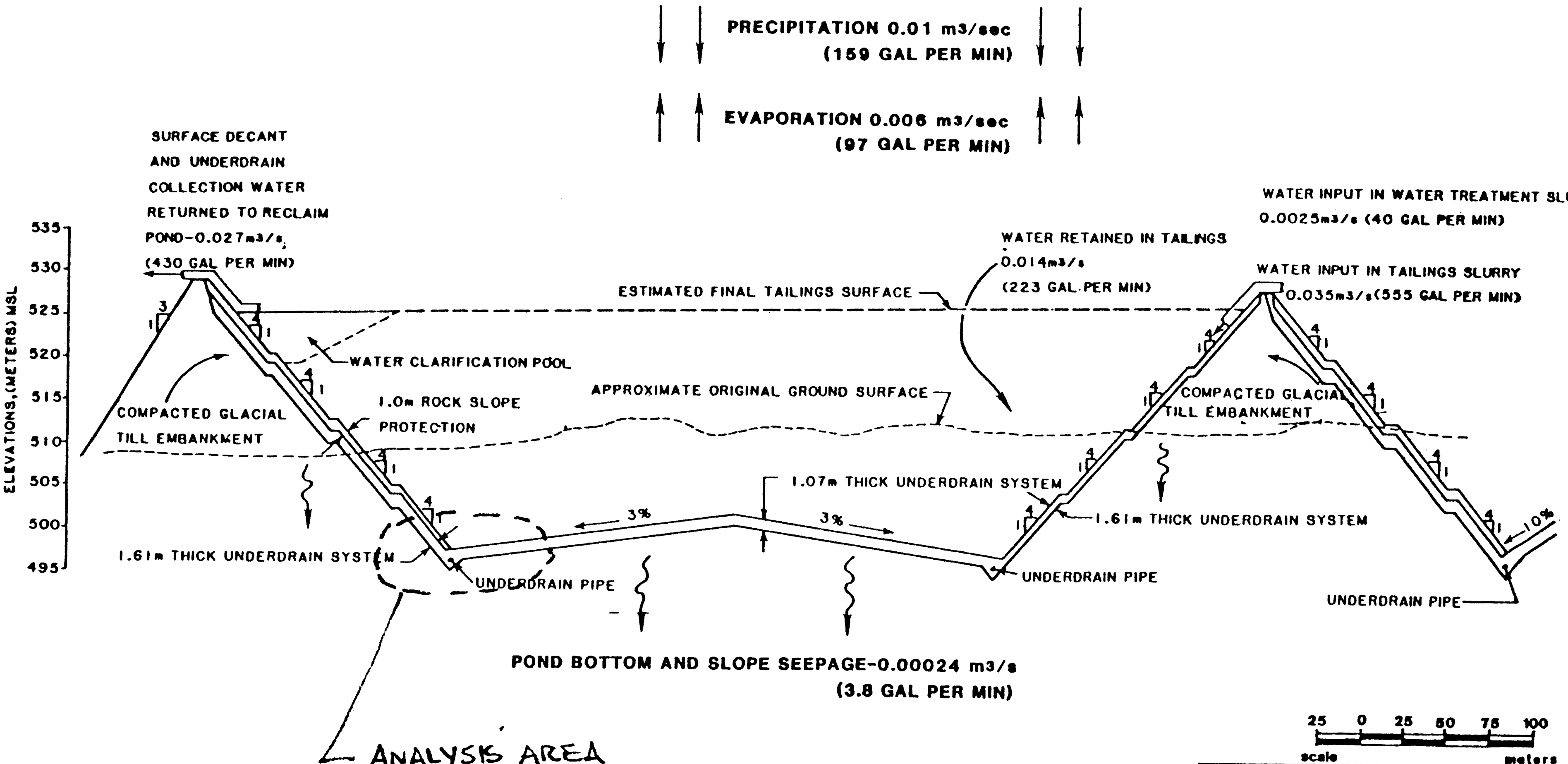
K = 1.4×10^{-7} m/s

Ref: Report No. FHWA-TS-80-224
Highway Subdrainage Design, August 1980

326-443 O - 80 - 5

TYPICAL POND WATER BALANCE DURING OPERATION

(COMPUTATIONS BASED ON POND T3 AREA WITH AVERAGE PRECIPITATION)



NOTE:

1) VERTICAL SCALE EXAGGERATED

2) PRECIPATATION 0.78m/YEAR
(30.77 IN PER YEAR)

3) EVAPORATION 0.59m/YEAR
(22.36 IN PER YEAR)
OVER 80% OF POND AREA

EXXON MINERALS COMPANY
CRANDON PROJECT

TITLE
WASTE DISPOSAL FACILITY TYPICAL TAILINGS POND WATER BALANCE

SCALE ABOVE	STATE WISCONSIN		COUNTY FOREST
DRAWN BY J.P. BECKER	DATE 8/82	CHECKED BY C.C. Schroeder	DATE 8-17-82
APPROVED BY	DATE	APPROVED BY	DATE
APPROVED BY	DATE	EXXON	DATE
DRAWING NO FIGURE 1.4-18	SHEET 1 OF 1		REVISION NO