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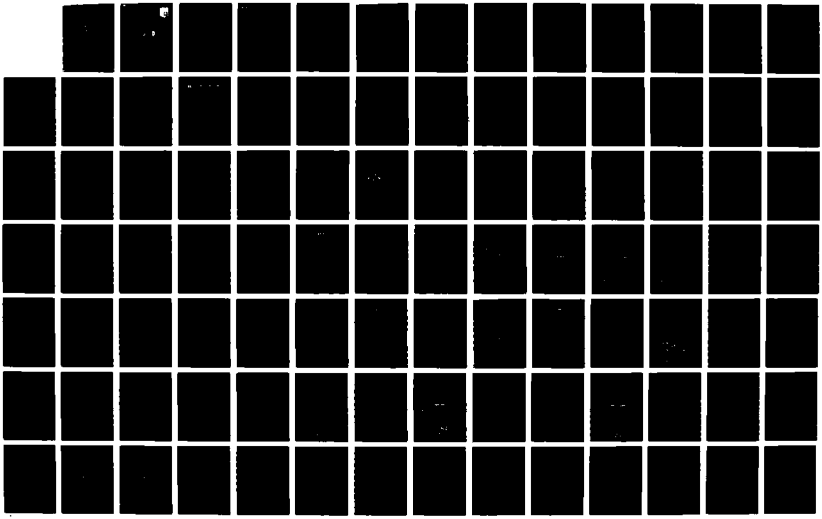

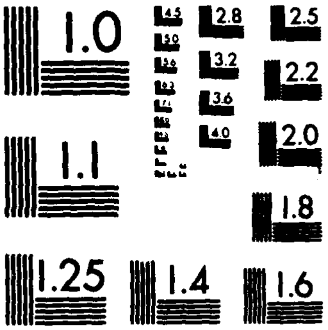

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AFWAL-TR-87-2042
Volume I

PRODUCTION OF JET FUELS FROM COAL DERIVED LIQUIDS

VOL I - Market Assessment for Liquid By-Products from the Great Plains Gasification Plant

J. E. SINOR

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In September 1986, the Fuels Branch of the Aero Propulsion Laboratory at Wright-Patterson Air Force Base, Ohio commenced an investigation of the potential of production of jet fuel from the liquid by-product streams produced by the gasification of lignite at the Great Plains Gasification Plant in Buelah, North Dakota. Funding was provided to the Department of Energy (DOE) Pittsburgh Energy Technology Center (PETC) to administer the experimental portion of this effort. This report details the effort of JE Sinor Consultants, who, as a subcontractor to the DOE contract with the University of North Dakota Energy Research Center (UNDERC), determined the market potential of these by-product streams. This report describes the market potential of the by-product streams for the production of phenols, benzene, cresote, cresylic acids, coal tar pitch, paving materials, carbon black, naphthalene, rubber processing oils, as well as, jet fuels.

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FOREWORD

In September 1986, the Fuels Branch of the Aero Propulsion Laboratory at Wright-Patterson Air Force Base, Ohio commenced an investigation of the potential of production of jet fuel from the liquid by-product streams produced by the gasification of lignite at the Great Plains Gasification Plant in Buelah, North Dakota. Funding was provided to the Department of Energy (DOE) Pittsburgh Energy Technology Center (PETC) to administer the experimental portion of this effort. This report details the effort of JE Sinor Consultants, who, as a subcontractor to the DOE contract with the University of North Dakota Energy Research Center (UNDERC), determined the market potential of these by-product streams. DOE/PETC was funded through Military Interdepartmental Purchase Request (MIPR) FY1455-86-N0657. Mr William E. Harrison III was the Air Force project engineer, Mr Gary Stiegel was the DOE/PETC project engineer.

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INTRODUCTION

The University of North Dakota Energy Research Center requested J. E. Sinor Consultants Inc. to carry out a marketing analysis for liquid by-products from the Great Plains coal gasification plant at Beulah, North Dakota. These liquid streams are currently burned as plant fuel within the plant. At the same time, lignite fines, which cannot be accepted by the gasifiers, must be sold to the adjoining power plant. If these fines or another inexpensive replacement fuel could be utilized for plant fuel, then the liquid by-product streams could be processed as necessary and sold into higher-value markets.

The objective of this study was to identify those products which would yield the highest net return to the facility owners, after paying capital and operating costs of any new processing units needed. The scope of the study included the definition of market volumes, product specifications, market locations, prices, transportation costs, and estimated manufacturing costs.

Factors to be considered in the implementation of a by-products manufacturing and marketing scheme include the internal transfer cost which must be assigned to the raw liquids, long distances to some markets, and questions about the ability of the liquid products to meet product specifications. In addition, recent large swings in world oil prices have cast doubt on the ability of some coal-derived products to compete with petroleum-derived products in the near future. A recommended course of action is developed in light of constraints and uncertainties.

Although the funding for this study was derived from an overall investigation of the feasibility of producing military jet fuels from the Great Plains liquid streams, the scope of the study was not limited to a specific product slate involving jet fuel. The economic calculations assumed that the entire liquid streams could be made available for any product of interest.

EXECUTIVE SUMMARY

FROM A TECHNICAL STANDPOINT, THE VARIETY OF PRODUCTS WHICH COULD BE MADE FROM THE GREAT PLAINS LIQUID BY-PRODUCTS STREAMS IS ALMOST UNLIMITED. The coal tar refining industry has had a long history. Such products as jet fuel were produced in the 1940's and 1950's. However, there has never been a large-scale coal refining industry in the United States based on low-temperature tar products, such as the tar oil from the Great Plains coal gasification plant.

THE TAR OILS PRODUCED IN THE GREAT PLAINS PLANT HAVE SOME SIGNIFICANT DIFFERENCES FROM THE MATERIALS PRODUCED AS COKE OVEN BY-PRODUCTS. This creates a handicap for Great Plains products in certain markets. Creosote produced at Great Plains, for example, should be an effective wood preservative, but it is barred from major markets because of existing specifications. Penetrating these markets will require changing the specifications.

THE GREAT PLAINS REGION IS BASICALLY SELF-SUFFICIENT IN REFINED PETROLEUM PRODUCTS. Any new production of materials such as jet fuel or gasoline would have to displace existing production in the region. Because the Great Plains output would be less than one percent of regional demand, any effects on prices will be minimal.

THERE IS A LARGE ENOUGH DEMAND FOR MILITARY JET FUEL IN THE IMMEDIATE REGION TO ABSORB ANY PRODUCTION FROM GREAT PLAINS. A contract to produce jet fuel for the Air Force bases in North Dakota should be a prime objective for the Great Plains plant.

ONLY ONE REFINERY IN THE REGION WILL HAVE THE CAPABILITY TO ACCEPT GREAT PLAINS TAR OIL AS A FEEDSTOCK. This is the refinery in Regina, Saskatchewan, which is building a 50,000 barrel per day heavy oil upgrading facility.

THE ACCURACY OF THE INFORMATION AVAILABLE FOR EVALUATING THE ECONOMICS OF UPGRADING THE LIQUID BY-PRODUCT STREAMS IS INSUFFICIENT FOR MAKING INVESTMENT DECISIONS AT THIS TIME. This is partly due to the fact that there has never been a large, modern low-temperature tar refinery in operation in this country. As a result, it is not feasible to give definitive answers about the economics. Results in this study are order-of-magnitude only.

A MAJOR DEFICIENCY IN THE COST DATA AVAILABLE IS A RELIABLE ESTIMATE FOR THE COSTS OF EXTRACTING ALKYLPHENOLS FROM THE CRUDE PHENOL AND TAR OIL STREAMS. The calculated return on investment differs by a factor of two when different cost estimates are used for the extraction step.

RECOVERY OF THE PHENOLS IN A PURE STATE IS THE KEY TO A PROFITABLE BY-PRODUCTS OPERATION. These materials do not have to compete directly with large-volume petroleum refinery operations, as would be the case for gasoline or other fuel products.

THE MARKET OUTLOOK FOR BENZENE AND PHENOL IS POSITIVE. Demand for light aromatics as octane-improvers will be strong because of the total elimination of tetraethyl lead for this purpose. At the same time, chemical demand is starting to recover from a several-year slump.

SMALL MARKET VOLUMES CONSTITUTE A RISK FOR SOME POTENTIAL BY-PRODUCTS. Maximum creosote production from the Great Plains plant could represent one half of the smaller creosote market expected in the future. Maximum cresylic acids production could supply a large fraction of the total natural cresylic acids market in the United States. A marketing strategy for cresylics will require penetration of overseas markets. Products such as benzene and phenol carry no such market volume risk.

THE STEEP DROP IN WORLD OIL PRICES IN 1986 HAS MADE UNPROFITABLE THE MANUFACTURE OF PRODUCTS COMPETING DIRECTLY WITH PETROLEUM. The table below shows that benzene and the phenols have been proportionately less affected.

COMPARISON OF 1985 AND 1987 PRODUCT PRICES
(Dollars per Pound)

Product	1985	1987
Gasoline	0.14	0.08
Methane	0.54	0.34
Jet Fuel, JP-4	0.12	0.07
Phenol	0.28	0.21
Cresols	0.45	0.38
Xylenols	0.48	0.50
Benzene	0.18	0.16

THE PRODUCTION OF REFINED FUEL PRODUCTS IS UNLIKELY TO BE COMPETITIVE WITH PETROLEUM IN THE NEAR FUTURE. The economies of scale which can be achieved with high-volume petroleum refining make it extremely unlikely that a modest-sized by-products operation would be effective in the fuels area. Products derived from the unique nature of the gasification plant streams (i.e. high aromaticity, high phenols) offer a better opportunity for profitable operation.

CONCENTRATIONS OF MOST INDIVIDUAL COMPOUNDS IN THE TAR OIL STREAM ARE PROBABLY TOO SMALL TO BE ECONOMICALLY IMPORTANT. Coal tar oil is an extremely diverse material, with hundreds, even thousands of individual species identifiable. Although some of these would be valuable as specialty chemicals, the concentrations of most are too low to be of economic interest. Recovery and sale of individual chemical species may provide a fringe benefit, but will never be a major economic force.

A LONG-TERM TREND AWAY FROM COMPLEX FEEDSTOCKS TO PURER SYNTHETICS CONTINUES. At one time a large number of chemicals were produced from coal tar. The number has dwindled steadily over the last 20 years due to declining coal tar production combined with increasing competition from cheaper and higher purity synthetics made from petroleum. Within the last few years the coal tar refining industry has greatly diminished. Rather than attempting to fight this trend, a by-products operation should be structured to produce what the market wants, if at all possible. Pure benzene and phenol would be ideal products.

MARKETS FOR MIXTURES MAY REQUIRE A LONG TIME TO DEVELOP. With pure compounds, marketing is a matter of meeting specifications then offering a reliable source and price. With complex mixtures, specifications are unlikely to be able to shield a user from risk in using a new product derived from coal gasification by-products. Therefore, prolonged market development efforts may be required, with large samples carried through the buyer's manufacturing process, and the end-product subjected to extensive reliability and quality tests.

REQUIRED PRE-MANUFACTURING NOTICES UNDER THE TOXIC SUBSTANCES CONTROL ACT WILL BE A MAJOR DETERRENT TO ESTABLISHING NEW MARKETS FOR BY-PRODUCTS. Products sold from the plant should be kept as generic as possible in order to avoid the need for PMN's for every possible end-product. In any case, a PMN strategy will be a major factor in project planning.

THE OPTIMUM PRODUCT SLATE WOULD BE MILITARY JET FUEL PRODUCED FROM THE TAR OIL STREAM PLUS BENZENE AND PHENOL PRODUCED FROM THE NAPHTHA AND CRUDE PHENOLS STREAMS. The production of jet fuel would require government support, but the benzene and phenol operations should be profitable whether or not a jet fuel facility is implemented. If no support can be obtained for jet fuel production, the tar oil may find its best outlet as creosote.

ECONOMICS WILL BE STRONGLY DEPENDENT ON THE TRANSFER VALUE WHICH MUST BE ASSIGNED TO THE RAW LIQUID STREAMS. This will be determined by the cost of converting the gasification plant from liquid-fired to lignite-fired operations, and by the alternative price which could be received for the lignite fines. The table below highlights the effect that the liquid transfer value will have on by-product economics.

Product	DCFROR, Percent, If Liquids Value Is $1/MMBTU	DCFROR, Percent, If Liquids Value Is $3/MMBTU
Benzene	23.3	16.9
BTX	26.8	20.0
Benzene + Phenol	35.9	22.5
Multiple Products	28.9	18.9

LEVERAGED FINANCING COULD INCREASE INDICATED RETURNS TO ABOVE 40 PERCENT. The above rates of return are based on constant-dollar analysis, with 100 percent equity financing. Adding inflation would raise the rate of return by about the rate of inflation (forecast to be approximately five percent). Leveraged financing would also raise the rate of return. Borrowing 70 percent of the capital cost at 12 percent interest would increase the DCFROR by about another 10 percentage points.

TRANSPORTATION COSTS ARE A MAJOR DETERRENT TO PRODUCING LOW-VALUE PRODUCTS IN THE GREAT PLAINS REGION. There are no large markets within economical reach of truck transport. For shipment by rail or combined rail and barge, a generic average cost of transportation will be about $6 per barrel. The table below highlights the effect that transportation costs can have on the rate of return (basis is liquids transfer cost of $2 per million BTU).

EFFECT OF TRANSPORT COSTS ON RATE OF RETURN

Product	DCFROR, Percent, No-Cost Transportation	DCFROR, Percent, High-Cost Transportation
Benzene	23.1	17.1
BTX	26.8	20.1
Benzene + Phenol	31.5	23.8
Multiple Products	28.1	20.0

THE PRODUCT PRICE OUTLOOK IS GENERALLY POSITIVE. The worldwide decline in commodity prices which occurred over the last few years appears to have reached bottom. Many facilities have been closed. Further closures are unlikely to have a substantial additional effect. Increased product prices will have a very large effect on the rate of return for a by-products operation, as illustrated below (basis is liquids transfer cost of $2 per million BTU).

EFFECT OF PRODUCT PRICES ON RATE OF RETURN

Product	DCFROR, Percent, If Prices Fall By 25 Percent	DCFROR, Percent, If Prices Increase By 50 Percent
Benzene	12.6	32.1
BTX	15.5	36.2
Benzene + Phenol	15.2	46.1
Multiple Products	12.5	41.1

THE POTENTIAL PROFITABILITY OF A BY-PRODUCTS UPGRADING OPERATION WARRANTS SERIOUS CONSIDERATION FOR IMPLEMENTATION REGARDLESS OF WHETHER SUPPORT CAN BE OBTAINED FOR DEMONSTRATING THE PRODUCTION OF JET FUEL FROM COAL LIQUIDS. The first priority should be to obtain improved estimates for the costs of extracting benzene and phenols from the naphtha and crude phenols streams.

BASIS FOR THE STUDY

The basis for the market analyses carried out in this study is information on flow rates and stream compositions provided by ANG Coal Gasification Company. There are three by-product liquid streams produced in the gasification plant with quantities as shown in Table 1.

Current opinion is that the dusty tar stream must continue to be recycled to the top of the gasifiers in order to hold down the dust in the gas stream. Therefore, only the three streams shown in Table 1 were considered as being available for by-product production. All three of these streams are presently being burned for fuel within the gasification plant complex. Typical analyses and the high and low values observed for these three streams are provided in Tables 2 and 3.

Some of the potentially most valuable components in the phenol and tar oil streams are the tar acids. The total tar acids available are indicated in Table 4. Average quantities contained in the phenol and tar oil streams are indicated in the first tow columns of numbers. It is assumed that these tar acids could be concentrated into a 70 percent fraction of the crude phenol stream and a 30 percent fraction of the tar oil stream, amounting to 67.77 million pounds per year and 95.96 million pounds per year, respectively. The last three columns then give the average, low and high values for total quantity of each tar acid in the combined streams.

The agreed basis for the marketing analysis was that only products for which manufacturing processes are commercially available would be considered.

TABLE 1

LIQUID BY-PRODUCTS FROM THE GREAT PLAINS PLANT
(Based On 91 Percent Onstream Factor, Gas Production At 137.5 Million SCFD)

Stream	Specific Gravity	Flow Rate
Tar Oil	1.016	319.9 Million pounds per year
Crude Phenol	1.059	96.8 Million pounds per year
Rectisol Naphtha	0.825	59.2 Million pounds per year

TABLE 2

TYPICAL ANALYSES FOR LIQUID BYPRODUCTS

	Rectisol Naphtha			Crude Phenol			Tar Oil		
	Average	Low	High	Average	Low	High	Average	Low	High
Specific Gravity	0.825	0.806	0.845	1.072	1.066	1.088	1.014	1.000	1.022
ASTM D-86 Distillation									
IBP, °F	100			210			210		
10%	120			365			250		
20%	140			380			360		
30%	160			385			400		
50%	180			395			440		
70%	195			425			520		
80%	215			470			640		
90%	230			525			690		
EP	270			570					
TBP Distillation									
IBP, °F							225		
10%							354		
20%							399		
30%							435		
50%							525		
70%							637		
80%							711		
90%							804		
EP							975		
Heating Value (LHV-BTU/lb)	17,200	16,400	17,500	1,400	13,600	14,400	16,500	16,300	16,800
Flash Point									
COC (°F)				205			190	180	200
PMCC (°F)				145			125	115	130
Pour Point (°F)				0	-20	5	60	55	65
Viscosity (SUS)									
80 °F				68	62	73	1,000	800	1,200
120 °F				45	40	49	60	59	62
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TABLE 3

COMPONENT ANALYSES FOR LIQUID BYPRODUCTS

	Rectisol Naphtha			Crude Phenol			Tar Oil		
	Average	Low	High	Average	Low	High	Average	Low	High
Elemental Analysis-Dry-(Wt%)									
C	87.0	86.0	88.5	79.0	76.0	82.0	87.7	83.0	91.0
H	9.0	8.2	10.1	7.2	6.7	8.5	8.6	7.7	9.2
N	0.3	0.1	0.4	0.4	0.4	0.6	0.6	0.4	0.8
S	1.5	0.9	2.3	0.2	0.1	0.6	0.4	0.4	0.5
0 (By Diff)	2.2	1.6	3.9	13.2	10.1	19.7	2.7	0.5	6.9
PONA (LV %)									
Paraffins	14								
Olefins	4								
Naphthenes	16								
Aromatics	66								
Trace Metals/ppm									
Arsenic							<1		
Nickel							<1		
Vanadium							<1		
Iron							15		
Component Analysis (Wt%)									
Water	0.5	0.2	0.8	4.5	4.0	5.5	2.0	1.5	4.0
Methanol	2.0	0.3	4.3						
Acetone	5.0	4.0	8.2						
MEK	3.0	2.0	5.0						
Benzene	36.0	28.0	50.0						
Toluene	15.0	12.0	21.0						
Xylene	3.0	2.0	6.0						
Or Lt Aromatics				0.8	0.5	1.2	2.5	1.5	6.0
Phenols				31.2	27.0	40.0	1.5	0.5	3.5
Cresols				21.7	20.0	28.8	3.6	2.0	4.5
Guiacol				0.8	0.0	1.4	0.1	0.0	0.2
Ethylphenol				2.1	0.5	3.0	0.8	0.5	1.0
Xylenols				4.6	3.2	9.8	2.5	2.0	7.0

TABLE 4

POTENTIAL TAR ACIDS PRODUCTION
(Million Pounds Per Year)

Component	Crude Phenol Fraction	Tar Oil Fraction	Total Tar Acids Production		
	Avg	Avg	Avg	Low	High
Phenol	30.20	4.64	34.84	30.13	38.89
O-Cresol	5.81	3.97	9.78	8.71	11.19
M,P-Cresol	15.20	7.49	22.68	20.06	25.33
Subtotal	21.01	11.45	32.46	28.77	36.52
Guiacol	0.77	0.32	1.09	0.71	2.13
2,6 Xylenol	0.29	0.64	0.93	0.66	1.21
2,4/2,5 Xylenol	1.84	3.93	5.77	4.46	6.66
3,5 Xylenol	2.03	2.94	4.98	3.87	5.90
2,3 Xylenol	0.29	0.48	0.77	0.66	1.29
3 Ethylphenol	0.87	1.22	2.09	1.82	2.39
2 Ethylphenol	0.48	0.54	1.03	0.83	1.34
4 Ethylphenol	0.68	0.83	1.51	1.69	2.48
Subtotal	6.49	10.59	17.07	13.98	21.29
Total Tar Acids	57.70	26.68	84.38	72.88	96.69
Neutral Oil/Other	10.07	69.29	79.35	90.86	71.27
Total Product	67.77	95.96	163.73	163.73	167.96
Total Stream Rate	96.81	319.88			

MARKET ASSESSMENTS

MILITARY JET FUELS

The end product of primary interest to the Department of Defense is military jet fuel. Synthetic fuels have been widely proposed as military fuels for national security reasons. For the most part, jet fuel has been produced from the straight distillation of light petroleum crude oil. Because of changing feedstock characteristics in the future, jet fuel will have to be hydrotreated in order to meet military and commercial specifications. The continuing depletion of petroleum reserves in the United States has led the Air Force to evaluate the potential of alternate sources of jet fuels. They are greatly concerned about security of energy supply.

JET FUEL FROM SHALE OIL

The United States Department of Defense (DOD) developed an aggressive program known as "Project: Rivet Shale." A research and development phase was completed including testing of over 1.3 million gallons of shale-derived fuel in complete engine systems. The next phase, "Operation Validation," will involve the use of shale-derived JP-4 jet fuel at Hill and Mountain Home Air Force Bases. The production from Union Oil Company's Parachute Creek Oil Shale Project (Colorado) is planned to supply 100 percent of the jet fuel needs of both Air Force bases. Hence, for the near term, the Air Force will have an adequate supply of shale-derived jet fuel.

After the operational validation phase, which is expected to last two years, the Air Force plans to be in a position to accept JP-4 that is derived from shale oil in any percentage, at any location where the fuel is used.

The Department of Defense has played a very significant role in all the large-scale shale oil refining studies which have been done to date. This includes sponsoring the refining of 100,000 barrels of Paraho shale oil (Colorado) at the Sohio refinery in Ohio, refining of 40,000 barrels of Geokinetics oil (Utah) at the Caribou refinery in Utah, and the future refining of Union's output at the Gary refinery in Colorado. In addition, DOD has sponsored extensive laboratory Research and Development studies on western shale oil upgrading and refining.

In the early 1980s, the United States Air Force sponsored a number of bench-scale and pilot plant studies to ascertain the suitability of western shale oil to produce acceptable JP-4, meeting the current specifications. These efforts were with Sun Oil Company, Ashland Petroleum, UOP Process Division and Amoco Oil Company. Using different refining approaches it was concluded that western shale oil produced by a number of different recovery techniques was an excellent source of heavy naphtha and middle distillate materials. A shale-derived fuel was produced which exceeded all the requirements of the MIL-T-5624L specification. Because of the hydrorefining required to produce this fuel, there is a possibility of some lubricity problems in fuel-wetted close-tolerance components, i.e., fuel pumps, controls, etc. The United States Air

Force routinely uses surface-active corrosion inhibiting materials to reduce this problem and a ball-on-cylinder test is being standardized to test for the property.

JET FUEL FROM TAR SAND

In 1983 the Fuels Branch (AFWAL/POSF) of the Aero Propulsion Laboratory at Wright-Patterson Air Force Base, Ohio, awarded contracts to the Ashland Petroleum Company and to the Applied Research and Development Division (ARD) of Sun Oil Company to conduct the research on aviation turbine fuels produced from Kentucky and Utah bitumens. The goal of the program was a commercially viable processing scheme to produce high yields of aviation turbine fuel, grades JP-4 and JP-8, with a minimum energy efficiency of 70 percent and net production of coke and residual materials of no more than 10 percent. The program was completed in 1986.

The Air Force selected a pilot-scale produced Kentucky bitumen, recovered by Westken Petroleum Company as part of the Kensyntar program. The bitumen was recovered via an in situ wet combustion process from the Big Clifty deposit of Edmonson County, Kentucky. The Air Force also selected a pilot-scale produced Utah bitumen, recovered by the Chevron/GNC joint venture. The tar sand was mined from the Sunnyside deposit and the bitumen recovered via a solvent assisted water flotation process.

Each contractor investigated a different processing scheme. Ashland's approach to processing the Kentucky bitumen was based on established commercial processing techniques (Commercial Chemical Desalting, ART, RCC, Hydrotreating) used at their Cattletsburg, Kentucky refinery. Sun chose to process the bitumens using conventional refining processes for desalting, hydrovisbreaking, hydrotreating and hydrocracking.

Each contractor investigated three product slates; a product slate which minimized the cost of JP-4; a slate which maximized the production of JP-4; and a product slate which maximized the production of JP-8.

The processes all produced high quality JP-4 fuels. The processes also produced high quality JP-8 fuels.

At Ashland, four JP-4 (MIL-T-5624L) samples were produced by varying the severity of the final hydrotreater. These samples provided a range of aromatics contents from conventional to extreme, and addressed the Air Force efforts to evaluate the effects of higher aromatics contents on jet engines. Increased aromatics levels offer cost reductions and increased fuel energy per unit of tank volume, but also result in decreased engine combustion liner life and increased smoke emissions. The JP-4 samples were excellent fuels. In contrast to conventional JP-4, this fuel showed very naphthenic character, with a low API gravity, hydrogen content, and K factor. Thermal stability and freeze point were excellent. Key characteristics of all the JP-4 samples varied linearly with aromatics content.

A JP-8 fuel (MIL-T-83133) was also prepared. The result was an extremely naphthenic fuel; existing hydrogen content specifications were met only by reducing the distillation end point of the fuel by about 70 °F. Thermal stability, freeze point, and water reaction for this fuel were outstanding. Smoke point, however, was marginal due to the low hydrogen content. Of particular interest, this fuel confirmed the high volumetric heating value anticipated for naphthenic or so-called "high density" fuels.

JET FUEL FROM COAL LIQUIDS

Not as much attention has been given to producing military turbine fuels from coal liquids as to the use of shale oil and tar sands. One reason is that the high level of aromatics in coal liquids makes them unsuitable (aromatics cause smoke) without hydroprocessing. Even a few percent naphthalenes in jet fuel are a problem. However, the work discussed under "Jet Fuel From Tar Sands" makes it clear that aromatic compounds can be converted to cycloparaffinic (naphthenic) compounds, which may be ideal jet fuels. In this case, coal-tar-oil-derived liquids might even be a preferred feedstock.

FUEL SPECIFICATIONS

Aviation gas turbine fuel represents only about 7 percent of the refinery production in the United States. The 1984 domestic production of naphtha-type military jet fuel (JP-4) was 221,000 barrels per day while the production of kerosene-type fuels (Jet A, JP-5, Jet A-1) was reported to be 922,000 barrels per day. The growing scarcity of light sweet petroleum could impact the future availability of a minor product such as jet fuels. For this reason, DOD has studied alternative refinery feedstocks for the future and evaluated their potential for producing aviation gas turbine fuels. The potential for modifying fuel specifications, making them more identifiable with the basic feedstocks, and improving aircraft performance has also been considered.

Jet fuels are the most critical product, in terms of quality, produced by the refining industry. The naturally occurring hydrocarbons in petroleum can be essentially fractionated with little additional processing to produce highly stable jet fuels. There are instances where fuels are mildly hydrotreated to remove sulfur but for the most part, chemical conversion processes have not been necessary.

In 1951 the United States Air Force standardized aircraft operations on JP-4 jet fuel in order to optimize performance and availability. Some of the most important chemical and physical properties of JP-4 are depicted in Table 5. This fuel can be characterized as a "wide-cut" fuel with a boiling range between 150 degrees F and 480 degrees F. This range optimizes the requirement for a vapor pressure between 2 and 3 psi at 100 degrees F and a maximum freeze point of -72 degrees F. These properties are required for high alt-

TABLE 5

PRIMARY MILITARY AVIATION FUEL SPECIFICATION REQUIREMENTS

	JP-4 (Jet B) MIL-T-5624L	JP-8 (Jet A-1) MIL-T-83133A
Specific Gravity, 60 F	0.751-0.802	0.775-0.840
Gravity, API @60 F	45-57	37-51
Distillation, Max Degrees F		
10% Recovered	---	---
20% Recovered	293	401
50% Recovered	374	---
90% Recovered	473	---
Final Boiling Point	518	572
Freezing Point, Degrees F	-72(-58)	-54
Viscosity, Centistokes @ -40 F, Max	---	8.0
Aromatics, Vol% Max	25.0 (20.0)	25.0 (20.0)
Olefins, Vol% Max	5.0	5.0
Sulfur, Wt%, Max	0.40 (0.30)	0.40 (0.30)
Net Heat Of Combustion, BTU/lb, Min	18,400	18,400
Hydrogen Content, Wt%, Min	13.6	13.6
Thermal Stability, JFTOT		
Pressure Drop, mm Hg, Max	25	25
Heater Deposit, Max	3	3
Flash Point, Degrees F, Min	---	100
Vapor Pressure, Reid, psi,	2-3	---

itude operations and low ambient temperature conditions at certain air bases. Chemical composition is controlled by limits on aromatic, olefin, sulfur and mercaptan sulfur contents. For operations where JP-4 may not be available, a kerosene-type fuel, specification JP-8, may be used. The Navy fuel specification is JP-5, which is identical to JP-8, except for a minimum flash point of 140 °F, for safety on aircraft carriers.

Although made up of many different hydrocarbons, jet fuels consist essentially of four general types of compounds: paraffins (including isoparaffins); cycloparaffins or naphthenes; aromatics; and olefins. The proportion of each compound type varies with the different types of crude oils and the processing needed to produce the fuel. A typical fuel will contain hundreds of different compounds. Except for restrictions on aromatics and olefins, the proportions of hydrocarbon types are not directly controlled. The requirements on density, energy content, freeze point and hydrogen content favor paraffinic or isoparaffinic based fuel. The hydrocarbon constituents of most JP-4 fuels are primarily normal or isoparaffins (50-70 volume percent) and cycloparaffins (20-40 volume percent).

The hydrocarbon-type composition of a typical petroleum JP-4 is depicted in Table 6. The refiner produces JP-4 from a blend of 60-70 percent light naphtha and 30-40 percent kerosene in terms of crude oil fractions. The commercial specification for the wide-cut fuel is designated as Jet B and is similar, with a few minor exceptions, to JP-4, as indicated in Table 5.

The basic differences between Jet A-1 and JP-8 are the additives required for military operations. The "average" boiling range for Jet A-1 is between 350 degrees F and 520 degrees F where volatility is limited by a flashpoint minimum of 100 degrees F. This fuel has a freeze point maximum limit of -54 degrees F. The hydrocarbon constituents in this fuel are, in general, denser than JP-4.

HIGH DENSITY JET FUEL

The possibility of modifying jet fuel specifications has been the objective of various research efforts over the years. Most of these efforts were aimed at reducing fuel costs while minimizing any effect on aircraft performance. One way of doing this is reducing the hydrogen requirements and increasing aromatic content thus eliminating the expense of hydrotreating. There is also a benefit to be gained by allowing the jet fuels to become more cyclic, thereby increasing fuel density and allowing additional range. A major increase in density is experienced for each ring formed from a given carbon-number species. Methyl or ethyl substitution generally does not lower the density and major improvements in freezing point depression can be realized. Volumetric heating values increase with density. Therefore large concentrations of cyclic paraffins (naphthenes) could increase the range of aircraft and maintain good low temperature capability. Table 7 shows the effect of cyclization in terms of two representative C-10 hydrocarbons, n-decane and decalin (decahydronaphthalene). These compounds are components in varying amounts in jet fuels. The decalin, which is a bi-cyclic saturated hydrocar-

TABLE 6

TYPICAL HYDROCARBON COMPOSITION OF JET FUELS
(Modified ASTM Method D-2789)

Hydrocarbon Type	JP-4 Composition Weight %	Jet A-1 Composition Weight %
Paraffins	66.0	44.5
Cycloparaffins	16.7	36.2
Alkylbenzenes	15.8	16.5
Indans and Tetralins	1.0	2.3
Naphthalenes	0.5	0.5
Total	100.0	100.0

TABLE 7

PROPERTIES OF C-10 HYDROCARBONS

	n-Decane	Decalin
Formula	$C_{10}H_{22}$	$C_{10}H_{18}$
Molecular Weight	142.29	138.25
Specific Gravity	0.7342	0.9011
Boiling Point, Degrees F	345.5	384.5
Freeze Point, Degrees F	-21.4	-45.6
Characterization Factor, K	12.61	10.50
Hydrogen, Wt%	15.59	13.12
Net Heat Of Combustion		
BTU/Pound	19,017	18,324
BTU/Gallon	116,410	137,660

bon, produces a denser material, with a lower freeze point and an 18 percent increase in volumetric heating value. However, the drawback to using cyclic hydrocarbons is the reduction in hydrogen content, which affects the combustibility in terms of increased flame radiation and soot formation.

Worldwide there is a variety of crudes that might be characterized by the dominant hydrocarbon types present in the mixtures. For example, paraffinic crudes are generally waxy, hence, they are selected for the manufacture of paraffinic lubricants. Naphthenic-type crudes are relatively low in paraffin content. They are selected for special applications or for the manufacture of aromatics and gasoline. Aromatic rich crudes may be high in asphaltene content. They are used for manufacturing gasoline and asphalt. In the United States, the production of low sulfur naphthenic crude is declining rapidly and it will soon become a scarce commodity. Hence, this raw material cannot be considered to be a major supply source for manufacturing higher density jet fuels.

However, modern petroleum refiners utilize a variety of thermal, catalytic and physical separation processes to manufacture high quality fuels from crude oils. In the refinery conversion processes where large molecules are cracked either thermally or catalytically, fractions rich in aromatic rings are produced. These fractions can be converted to naphthenes by various additional hydrogenation processes.

The Air Force recently reviewed the availability of hydrorefining and hydrotreating facilities in domestic refineries. From these specific refineries and their hydroprocessing capacities, the potential volume of naphthenic fuel that could be blended from these plants was estimated to be 1,772,700 barrels per day. This potential volume is far in excess of any demand. However, the resulting quality and characteristics of these fuel components would have to be determined.

Tar oil from coal gasification contains high levels of both naphthenes and aromatics. By selectively hydrogenating the aromatics, but not cracking the naphthenic rings, a high density fuel could be produced.

In order to evaluate a naphthenic fuel produced from an aromatic stream an effort was carried out under a research contract with Stone & Webster Engineering Corporation. A light pyrolysis fuel oil produced from the steam cracking of a petroleum gas oil fraction was converted into jet fuel. The raw aromatic fuel oil was converted into naphthenic products by hydrogenation in a pilot plant operation carried out at the Institute Francais de Petrole at Rueil-Malmaison, France. Table 8 presents the critical fuel properties and compares them with the starting feedstock.

This sample of naphthenic fuel (JP-8X) has the same volatility as JP-8 or Jet A-1, essentially a kerosene. The high density JP-8X fuel is 93.6 percent naphthenic (cycloparaffins). When comparing the volumetric heating value of this JP-8X to conventional JP-4, the energy increase is nearly 12.5 percent. For certain volume limited aircraft this energy increase could result in

TABLE 8

HIGH DENSITY JET FUEL PRODUCTION

	Feedstock Pyrolysis Fuel Oil	High Density JP-8 (JP-8X)
Specific Gravity, 60 F	0.978	0.872
Net Heat of Combustion		
BTU/Pound	16,881	18,271
BTU/Gallon	138,060	135,425
Hydrogen, Wt%	8.33	13.25
Flash Point, Degrees F	175	134
Boiling Range, Degrees F	392-562	369-500
Freeze Point, Degrees F	---	-100
Thermal Stability	---	Excellent
Viscosity, Centistoke @ -40 F	74	21
Chemical Analyses		
Naphthenes, Wt%	---	93.6
Aromatics, Wt%	100	6.4
Paraffins, Wt%	---	0

comparable range increases. The JP-8X prototype fuel therefore offers promise as a range extender for aircraft.

Such a fuel could be derived from many of the refinery feedstocks of the future, such as heavy oils, tar, bitumen, and coal liquids. The cyclic nature of all these materials makes them ideal for a higher density product if the hydrocarbon ring is preserved in the processing.

MILITARY JET FUEL DEMAND

Total jet fuel consumption by the United States Air Force is approximately 220,000 to 240,000 barrels per day. However, within a reasonable marketing radius of the Great Plains plant, there are only four air bases (Figure 1). Current demand at these bases is given below:

Grand Forks	2,348 barrels per day
Minot	2,479 barrels per day
Malmstrom	130 barrels per day
Ellsworth	1,300 (currently shut down)

PRICES AND MARKET STRUCTURE

Military fuel purchases are obtained by open bid, and therefore follow the prices for commercial jet fuel very closely. Supplies for the air bases are generally let for bid once a year. The most recent contracts have a bid date of October 1986. The results are listed in Table 9. These contracts are for one year, and have escalation and de-escalation clauses depending on posted prices for petroleum products in the region.

Because of the escalation clauses, the base prices in the contracts, as listed in Table 9, actually have very little meaning. The contract is typically written with two complex escalation clauses. The first clause determines the delivered price. It is based on published prices in Platts and another publication. Two weighting factors are used. Seventy percent weight is assigned to a formula involving the price of unleaded gasoline and thirty percent weight is assigned to a formula involving reported contract prices for commercial jet fuel (Jet A).

The second escalation clause is applied after delivery, when the Department of Energy Petroleum Marketing Monthly is issued. Depending on the factor, the jet fuel supplier may then either receive an additional payment, or may have to make a refund to the government.

To illustrate the importance of the escalation clauses, Table 9 indicates that current (April 1987) delivered prices to Grand Forks, North Dakota should be in the range of $0.80 per gallon. Actual deliveries in April, 1987 are running about $0.45 per gallon.

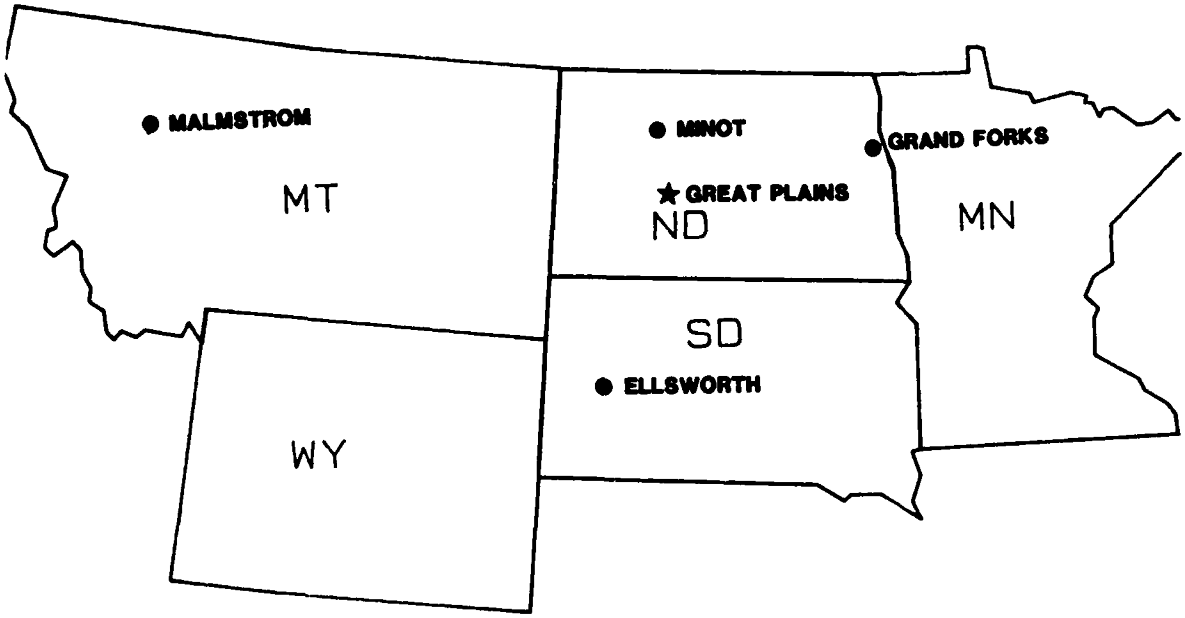


FIGURE 1

AIR FORCE BASES IN GREAT PLAINS REGION

TABLE 9

OCTOBER 1986 BID PRICES FOR JP-4 DELIVERED TO AIR FORCE BASES
(For Deliveries Through September, 1987)

Base	Quantity Gallons	Vendor	Price $/gallon
Grand Forks, ND	15,000,000	Ashland	0.775
	15,000,000	Ashland	0.79
	3,320,000	Ashland	0.81
	2,680,000	Western Petroleum	0.8335
	36,000,000		
Minot, ND	12,600,000	Western Petroleum	0.8510
	12,600,000	Western Petroleum	0.8510
	12,600,000	Farmers	0.8631
	200,000	Ashland	0.8635
	38,000,000		
Malmstrom, MT	2,000,000	Black Eagle	0.91406
Ellsworth, SD	Not Operating		

Intermediate resellers, such as those listed in Table 9, are able to function in this market only by having agreements with refineries which exactly parallel the government escalation clauses. They are able to work in this way with some refineries simply because the refineries do not want the problems of dealing directly with the government themselves. The intermediate sellers deliver the product directly form the refinery to the airbase, to avoid any chance of the additives or other specification properties deteriorating during storage.

Because of the limited military jet demand in the immediate region, and the once-a-year bid process, it would be impractical to build a free-standing facility targeted to this market. An advance purchase contract such as that which was provided by the Defense Department for the shale oil from Unocal's Parachute, Colorado shale oil plant, would be necessary.

DEMAND OUTLOOK

Although the Department of Defense makes five-year projections of military fuel requirements for internal use, these projections are classified and are not available for public release. With no major change in aircraft engines planned in the near future, and a stable world political situation, it is assumed that military jet fuel demand will remain approximately constant.

PETROLEUM PRODUCTS

INTRODUCTION

The liquid by-product streams from the Great Plains plant could be processed by petroleum refining techniques to make a variety of products competing with conventional refined petroleum products.

The objective of the next section is to describe the overall petroleum refining network in which North Dakota and the Great Plains plant operate. This entails examining the production, consumption and movements of crude oil and refined products in the Great Plains region. For purposes of this analysis, the Great Plains marketing region is defined as the states of North Dakota, Minnesota, South Dakota, Wyoming and Montana, and the provinces of Manitoba and Saskatchewan.

CRUDE OIL

Pipeline Network

The network of major crude oil pipelines in the Great Plains region is shown in Figure 2. As seen in the figure, there are five pipelines which import crude oil into the region. Crude oil from Alberta, Canada enters Montana near Cut Bank. A pipeline also runs from Alberta into Saskatchewan. This line enters Saskatchewan near Macklin, then runs east through Manitoba and Minnesota to points east. Two other pipelines that import crude into the region run north from Iowa to Minneapolis, Minnesota. The fifth incoming line is the Frontier line, operated by Amoco. It is a new 16-inch line which leads from the Anschutz Ranch oil field, just inside Utah at the southwest corner of Wyoming, to Casper. At Casper it connects to the Amoco refinery and to the Platte and Sinclair pipelines. Ultimate capacity of the line is expected to be 120,000 barrels per day.

Wyoming is a major exporting state with five pipelines carrying crude oil out of the state. Two major pipelines export crude oil from Wyoming to the east. The 20-inch Platte (Marathon) pipeline connects Casper, Wyoming to St. Louis, Missouri. The 20-inch Amoco pipeline connects a large crude oil gathering system in Wyoming to Sterling, Colorado then to Freeman, Missouri and goes on to Whiting, Indiana. A Conoco crude oil line originating in Wyoming runs south to Cheyenne and Denver. It interchanges with the Platte line at Guernsey station. A four-inch pipe connects from Guernsey station to the Amoco system at Ft. Laramie station. The Conoco line carries both crude and asphalt to Denver, with a capacity of 56,000 barrels per day. To the west, an eight-inch Amoco crude oil pipeline runs to Salt Lake City from southern Wyoming. Amoco also has two parallel four-inch lines that run from southern Wyoming to Rangely, Colorado.

Production

The 1986 crude oil production for the Great Plains region states and provinces is presented in Table 10. Wyoming is by far the largest producer of crude oil in the region. Historical production figures are given in Table 11.

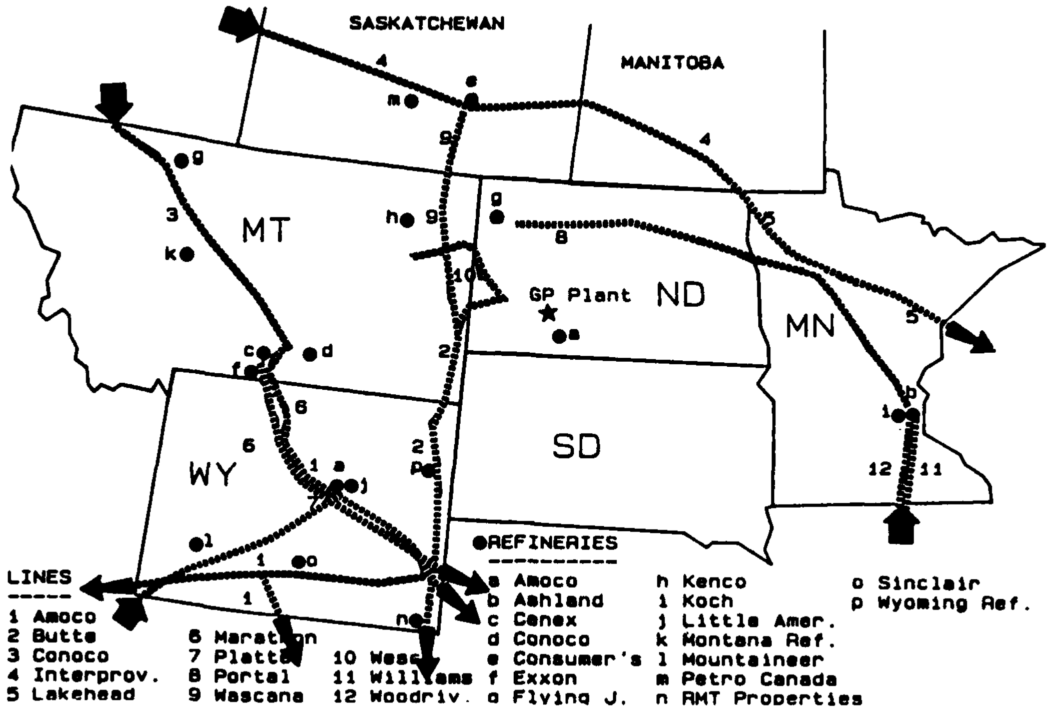


FIGURE 2

GREAT PLAINS REGION CRUDE PIPELINES

TABLE 10

PRODUCTION OF CRUDE OIL IN GREAT PLAINS REGION
(1986, Barrels Per Day)

State or Province	Production	Percent
Manitoba	14,200	1.8
Minnesota	0	0
Montana	74,200*	9.8
North Dakota	125,000	16.5
Saskatchewan	200,900	26.5
South Dakota	4,300	0.6
Wyoming	340,000	44.8
Total	758,000	100.0

*Estimation

Source: State Oil and Gas Commissions

TABLE 11

GREAT PLAINS REGION CRUDE PRODUCTION
(Units: Million Barrels Per Year)

	1979	1981	1983	1985	1986
Manitoba	3.67	3.42	4.65	5.16	5.19
Minnesota	0.00	0.00	0.00	0.00	0.00
Montana	29.96	30.81	29.67	29.85	27.08*
North Dakota	30.91	45.71	47.55	52.63	45.62
Saskatchewan	58.31	46.00	59.38	72.86	73.32
South Dakota	0.85	0.63	1.17	1.58	1.59
Wyoming	129.61	122.21	120.98	130.98	124.00*
Total	253.31	248.78	263.40	293.06	276.80

*Estimation

Source: State Oil and Gas Commissions

CRUDE OIL BALANCE

The locations of refineries in the region are also shown in Figure 2. Nominal crude oil distillation capacities of these refineries are listed in Table 12. Several small refineries in the region, which have been shut down, are not listed. Using an average of 85 percent operating capacity for the refineries in Table 11, a crude oil balance for the region is constructed in Table 13. Although a reasonable closure accuracy is indicated, it must be emphasized that no data were available for several of the pipelines. The near closure of the balance may be only fortuitous.

It is clear from the table, however, that refinery consumption is much less than crude oil production in the region, and that the region is a net exporter of crude oil. This is important because it suggests that any new source of liquids within the region will have to find a market by displacing other liquids to markets outside the region.

In other words, if the Great Plains plant should start using coal for plant fuel and convert its liquid by-products to fuels for sale within the region, the effect would probably be to reduce crude runs at existing refineries in the region. If these refineries are operating at less than full capacity while crude oil is being shipped out of the region, it indicates that they are unable to sell more product than they are presently producing. New production from Great Plains, therefore, would cause them to reduce crude runs. This, in turn, would push more crude oil into markets outside the region. Since the region is already a large net exporter, the infrastructure for such a market shift is in place, and the effect on crude oil prices would not be noticeable. The end result would most likely be a reduction in imports, either from Canada or from overseas sources shipping to the Gulf Coast. With an apparent net of exports over imports of 262,000 barrels per day for the region, an additional 5,000 barrels per day would have minimal impact on prices.

REFINED PRODUCTS

Pipeline Network

Refined products are produced at refineries in the Great Plains region and also imported into and exported from the region via products pipelines. A map of major refined products pipelines is shown in Figure 3. Refined products enter the region via the Dome, Interprovincial and Petroleum Transmission pipelines all from Alberta, Canada. The Williams, MAPCO, Dome, Amoco, Wyco, Medicine Bow, and Pioneer pipelines export refined products to many locations outside the Great Plains region.

Refinery crude capacities in the Great Plains region were listed in Table 11. Refineries located in Casper, Sinclair, and Cheyenne, Wyoming and in Billings, Montana serve Montana, Wyoming, Colorado and North Dakota. From Sinclair and Casper, Wyoming, products can move to southwestern Wyoming and Salt Lake City, Utah. The refineries located in Regina and Moose Jaw, Saskatchewan serve Saskatchewan and Manitoba and send some products to Minnesota and points south. Minnesota itself has an extensive products pipeline network connected with North Dakota, South Dakota and regions to the south of Minnesota.

TABLE 12

1986 GREAT PLAINS REGION REFINERY CAPACITIES

Refinery	Crude Distillation Capacity, BPCD	Location
Manitoba		
No Refineries		
Minnesota		
Ashland	67,143	St. Paul Park
Koch	137,000	Rosemount
Subtotal	204,143	
Montana		
Cenex	40,400	Laurel
Conoco	48,500	Billings
Exxon	42,000	Billings
Kenco	4,700	Wolf Point
Montana	6,300	Great Falls
Subtotal	141,900	
North Dakota		
Amoco	58,000	Mandan
Subtotal	58,000	
Saskatchewan		
Consumer's	40,000	Regina
Petro-Canada	13,300	Moose Jaw
Subtotal	53,300	
South Dakota		
No Refineries		
Wyoming		
Amoco	48,000	Casper
Frontier	28,800	Cheyenne
Little America	20,000	Casper
Sinclair	53,000	Sinclair
Wyoming	12,500	Newcastle
Subtotal	161,500	
Total	618,843 Barrels Per Calendar Day	

Source: Oil and Gas Journal

TABLE 13

GREAT PLAINS REGION CRUDE OIL BALANCE
(Units: 1,000 Barrels Per Year)

SUPPLY & IMPORTS

Production: Crude Oil	
Manitoba	5,194
Minnesota	0
Montana	27,080#
North Dakota	45,624
Saskatchewan	73,321
South Dakota	1,586
Wyoming	124,000#
Total	276,805
Pipeline Imports Into:	
Saskatchewan	
Interprovincial Pipeline	307,634
Wyoming	
Frontier Pipeline	18,250#
Montana	
Conoco Pipeline	17,338
Minnesota	
Woodriver Pipeline	34,218*
Minnesota	
Williams Pipeline	4,563
Total Imports	382,003
Total Supply and Imports	658,808

CONSUMPTION AND EXPORTS

Refinery Consumption	191,995
Exports From:	
Wyoming	
Conoco Pipeline, South	20,440
Platte Pipeline, East	36,594
Amoco Pipeline, Southwest	3,650
Amoco Pipeline, East	39,694*
Amoco Pipeline, West	14,600
Minnesota	
Lakehead Pipeline, East	362,733
Total Exports	477,711
Total Consumption & Exports	669,706

Closure Deficit = 669,706 - 658,808
= 10,898 thousand barrels

* Estimated capacity, not actual value

Estimation

TABLE 14

1986 REFINED PRODUCT PIPELINE IMPORT/EXPORT BALANCE FOR GREAT PLAINS REGION

(Units: 1,000 Barrels Per Year)

	Total Products	
	Net Imports	Net Exports
Manitoba	23,649	
Minnesota	12,305	
Montana		10,950
North Dakota	5,220	
South Dakota		1,898
Saskatchewan	1,092	
Wyoming		38,124
Regional Totals	42,266	50,972

Source: Pipeline Companies

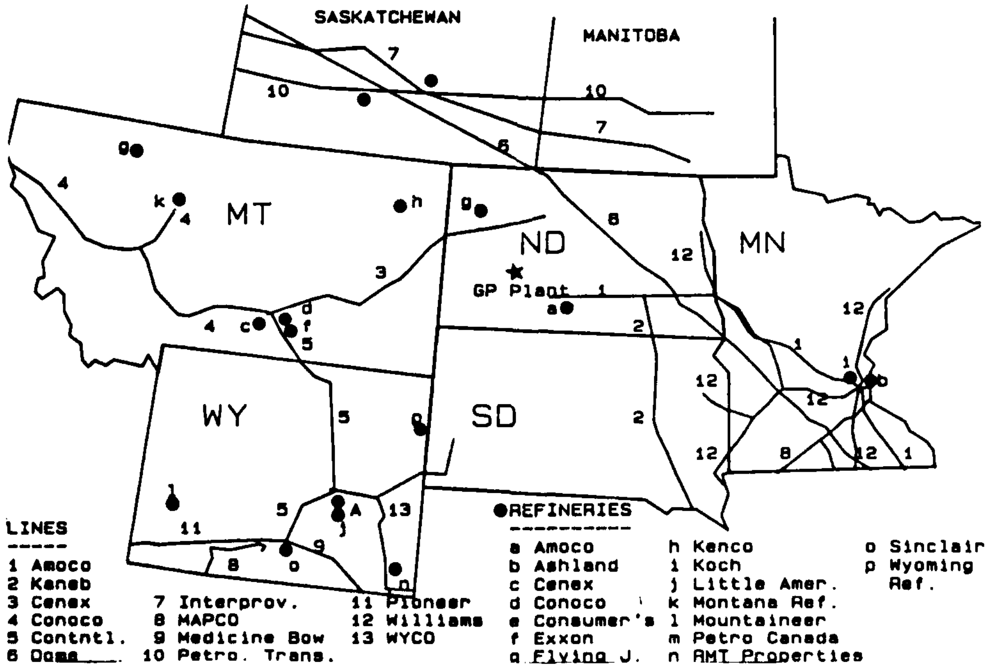


FIGURE 3

GREAT PLAINS REGION PRODUCT PIPELINES

A pipeline import/export balance (Table 14) constructed from the information available shows that the region is a slight net exporter of refined products. These figures must be viewed with much caution because some pipelines are missing from the accounting and because both refined products and natural gas liquids pipelines are included. Nevertheless, it indicates in a general way that refined products production in the region is nearly in balance with demand.

Refined Product Demand

Data on refined product demand (consumption) is available from the State Energy Data Report from the EIA. The most recent data available are for 1984. Attempts were made to update the EIA data by contacting individual state agencies, but information is scarce and some states keep no record of the type of information needed. Demand based on 1984 figures (EIA 1986 report) is summarized in Table 15.

Refined Products Production

There is no good source of public information on actual production by individual refineries. The nominal capacities listed in Table 12 are a good guide because if a refinery falls below about 70 percent capacity it usually becomes uneconomic and is likely to be shut down. However, actual production may be either below or above the design capacities listed in the Oil and Gas Journal. Numbers listed in Table 12 are barrels per calendar day, or average daily rates after accounting for all scheduled maintenance shutdowns. On the other hand, direct contacts with refineries were couched in terms of barrels per stream day.

North Dakota

The only refinery operating in North Dakota is the Amoco refinery in Mandan. Throughput is about 50,000 barrels per day. They run only 42 gravity light crude from North Dakota. Product mix is about 60 percent gasoline, 40 percent distillate.

Minnesota

Minnesota has the largest refining capacity of any of the states in the region although there are only two refineries, in the Minneapolis area. Koch Refining runs about 150,000 barrels per day of Canadian sour crudes. Output is mostly gasoline. The Ashland refinery runs 60,000 barrels per day of mostly North Dakota crude, with some Texas and some Canadian sour. Output is heavily gasoline, with some asphalt.

Saskatchewan

Saskatchewan has two refineries. However, the Petro-Canada refinery in Moose Jaw is only a topping operation to produce asphalt from heavy crude. They operate from April to October at 8,000-9,000 barrels per day. They had considered Great Plains tar as a blending stock for asphalt, but backed away because of environmental concerns. Consumers' Cooperative refinery in Regina runs about 45,000 barrels per day of light Alberta crude. Production is about 50/50 gasoline and diesel fuel.

TABLE 15

REFINED PRODUCT DEMAND IN GREAT PLAINS REGION (1985)
(Units: 1,000 Barrels Per Year)

	Manitoba	Minnesota	Montana	North Dakota	Saskat-chewan	South Dakota	Wyoming	Total
Asphalt & Road Oil	310	4,669	1,215	996	818	805	1,223	10,036
Aviation Gasoline	136	125	77	31	75	85	57	586
Distillate Fuel	5,452	18,187	9,445	7,486	7,845	4,892	7,403	60,710
Jet Fuel	383	6,975	692	1,759	522	1,071	102	11,504
Kerosene	447	142	12	21	659	37	44	1,362
LPG	83	7,994	1,160	727	665	1,692	2,202	14,523
Motor Gasoline	9,312	48,051	10,451	8,867	11,790	8,885	8,196	105,552
Residual Fuel	524	1,478	1,336	1,389	228	126	327	5,408
Other	40	4,495	2,871	1,070	32	156	2,635	11,299
Total	16,687	92,116	27,260	22,344	22,634	17,749	22,189	220,980

Source: DOE-EIA State Energy Data Report, April 30, 1986

Montana

Montana has one small and three large operating refineries. Montana Refining runs 7,000 barrels per day of one-half Canadian light and one-half Montana heavy sour crudes. Output is about 50 percent gasoline, 33 percent diesel, some #5 fuel oil.

The Conoco refinery swings between 33,000 barrels per day in the winter and 54,000 barrels per day in the summer depending on the market for asphalt. Feedstock is a mix of Canadian sweet and Wyoming sour crudes. The distillate product slate is mostly gasoline, with some diesel.

A similar type of operation is carried out at the Exxon refinery. It runs close to capacity of 50,000 barrels per day in summer and drops back to 35,000 barrels per day in winter. Input is a mix of sweet and sour crudes, while distillate output is 50 percent gasoline, 50 percent diesel and jet fuel.

The Cenex refinery has a listed capacity of 40,400 barrels per day.

Wyoming

Wyoming has the second largest refining capacity after Minnesota, and has the largest number of operating refineries at five.

The Little America refinery runs 24,000 barrels per day, using both sweet and sour crudes. They had at one point planned to distill some of the Great Plains tar oil, shipping some of the product back to Great Plains and using some of it. They eventually decided against it because of environmental concerns.

Frontier Refining (formerly RMT Properties) is running about 30,000 barrels per day of 60/40 sour/sweet Rocky Mountain crudes. They produce about 65 percent gasoline and 35 percent diesel. The Sinclair refinery runs 35,000 barrels per day, all 40 degree Wyoming and Anschutz sweet crudes.

The Mountaineer refinery in western Wyoming is basically a reclaiming operation, running 500 barrels per day of slop crudes. They usually pay less than $2.50 per barrel for feedstock.

Wyoming Refining runs 15,000 barrels per day of Wyoming sweet, making mostly gasoline which is marketed in South Dakota.

Natural Gas Liquids Production

The Great Plains region, Wyoming in particular, produces appreciable quantities of natural gas liquids. A breakdown by state and province is given in Table 16. The total for the region is 58,000 barrels per day or 21 million barrels per year. Natural gas liquids produced in the region are partially consumed in the region and partially exported. Natural gasoline is added to refinery streams.

TABLE 16
1985 GREAT PLAINS NATURAL GAS PLANT OPERATIONS
(Units: 1,000 Gallons/Day)

	No. of Plants	Gas Throughput MMcfd	Raw NGL, Ethane, Other	LPG	Natural Gasoline	Total
Manitoba	0	0.0	0.0	0.0	0.0	0.0
Minnesota	0	0.0	0.0	0.0	0.0	0.0
Montana	9	38.0	32.6	78.8	8.6	120.0
North Dakota	10	197.8	210.1	244.4	83.1	537.6
Saskatchewan	13	91.4	149.9	-	-	149.9
South Dakota	0	0.0	0.0	0.0	0.0	0.0
Wyoming	41	1,188.9	623.3	727.2	277.2	1,627.7
Total	73	1,516.1	1,015.9	1,050.4	368.9	2,435.2

MMcfd = Million standard cubic feet per day

Source: Oil and Gas Journal

From Table 15 it is seen that total LPG consumption is 14.5 million barrels per year, which is of the same order of magnitude as the production indicated in Table 16.

Refined Products Balance

On the basis of the above refinery survey, current refinery throughput in the Great Plains region is approximately 601,000 barrels per stream day (Table 17). Multiplying this by an average 94 percent onstream factor gives a calendar day average of 565,000 barrels per day. Although this is about seven percent above the value which was calculated earlier by assuming an 85 percent capacity factor, some of the refineries in the survey reported only capacity rather than actual rates, so the true value is probably 550,000 barrels per day (200 million barrels per year) or less.

Without having detailed information on the configuration of each refinery, it is impossible to calculate product yields on the basis of crude oil input. However, on a national average, the volume of products produced is approximately equal to the volume of crude oil processed. This is because most of the products have a lower density than the crude oil from which they are made. This gain in volume approximately offsets the amount of material consumed during processing. This is illustrated in Table 18 where the volume gain is approximately equal to the amount of refinery gas produced. We may therefore conclude that refinery output of refined products is 200 million barrels per year.

Table 15 shows total product demand of 221 million barrels per year, which may be compared to the sum of 200 million barrels per year from refinery production plus 21 million barrels per year of natural gas liquids production (221 million barrels per year total). The exact match of these two numbers is simply coincidental, because not all of the data are equivalent, and no consideration was given for movement of products into and out of the region. Nevertheless, it is clear that, on the whole, the Great Plains region is approximately in balance between production and consumption of refined products. This reinforces the earlier conclusion that any increased production in the region would either force a cutback at existing refineries or else force them to export outside the region. The latter will be difficult to achieve.

Comparison of Tables 15 and 18 shows that the relative demand for different products in the Great Plains region corresponds fairly well with the national average, with the exception of appreciably lower demand for residual fuel oil and jet fuel.

An overall refined products balance for the Great Plains region is given in Table 19. The indicated closure accuracy of 3.0 percent is much better than appears warranted by the data and the assumptions used, and therefore should not be relied upon excessively. The missing quantity is most likely a part of the pipeline data. Also, movements by truck, rail and barge are missing from the table.

An obvious conclusion to be drawn from the refined products balance is that it should be easier to market new production from Great Plains to the east rather than to the west. Although the region as a whole is approximately in balance, there is little direct interchange between the product-surplus area in Wyoming

TABLE 17

REFINERY OPERATING RATES IN GREAT PLAINS REGION

Refinery	Crude Distillation Rate, BPSD
Minnesota	
Ashland	60,000
Koch	150,000
Subtotal	210,000
Montana	
Cenex	40,400
Conoco	44,000
Exxon	42,500
Montana	7,000
Subtotal	133,900
North Dakota	
Amoco	50,000
Subtotal	50,000
Saskatchewan	
Consumers	45,000
Petro-Canada	4,250
Subtotal	49,250
Wyoming	
Amoco	35,000
Frontier	30,000
Little America	24,000
Sinclair	54,000
Wyoming	15,000
Subtotal	158,000
Total	601,150 Barrels Per Stream Day

Source: Contacts with refineries

TABLE 18

ANNUAL YIELDS FROM A BARREL OF CRUDE OIL

Product	Gallons Per Barrel	% Yield
Leaded Gasoline	6.9	16.4
Unleaded Gasoline	12.3	29.4
Distillate Fuel Oil	9.1	21.6
Residual Fuel Oil	3.0	7.1
Jet Fuel	4.0	9.5
Petrochemical Feedstocks	1.2	2.8
Asphalt and Road Oil	1.3	3.2
Still Gas (Refinery Gas)	2.0	4.7
Coke	1.5	3.7
Liquefied Gases	1.3	3.1
Lubricants	0.5	1.2
Kerosene	0.3	0.8
Miscellaneous	0.2	0.4
Special Naphthas	0.2	0.4
Wax	0.1	0.1
Processing Gain	-1.9	-4.5
Total	42.0	100.0

Source: American Petroleum Institute

TABLE 19

OVERALL REFINED PRODUCT BALANCE FOR THE GREAT PLAINS REGION

(Units: 1,000 Barrels Per Year)

	Total Products
Refinery Production	200,750
Natural Gas Liquids Production	21,000
Pipeline Imports From Other States Or Provinces	2,266
Total Supply & Imports	264,016
Consumption	220,980
Pipeline Exports	50,972
Total Consumption & Exports	271,952
Difference	7,936
Balance Closure, Percent	3.0

Source: DOE-EIA, state agencies, company contacts and the product-short area in Minnesota. North Dakota, like the region as a whole, appears to import only a relatively small fraction of its needs. Thus, if it were decided to market conventional fuel products from the Great Plains plant, it would be necessary to displace local production from conventional refineries.

Individual Products Demand

The 10-year demand history for individual petroleum products in the five-state region is shown in Figures 4 through 13. Overall petroleum demand (Figure 13) fell sharply from its peak value in 1978 until 1981, and has shown only small gains since. The pattern has been basically the same in all states. Individual products, however, may show quite different demand histories.

Commercial jet fuel, or Jet A, has registered long-term strong growth in demand in Minnesota (Figure 4). This is of course due to the presence of a regional international airport at Minneapolis-St. Paul, and no comparable facilities in the other states. Aviation gasoline, used in non-commercial aircraft, has shown declining sales in all states (Figure 5).

Motor gasoline is the major product of almost all refineries in the region, and its demand pattern (Figure 6) follows closely that for total petroleum products in all cases. Distillate fuel demand, on the other hand, shows some variation in pattern from state to state, and is generally subject to much wider swings in demand than gasoline.

Kerosene was once an important product in the region, but demand has almost disappeared over the last ten years (Figure 8). Liquefied petroleum gas (Figure 9) demand has declined from peaks in the 1970's, but in most cases the decline has not been great. The demand for residual fuel oil has declined almost as drastically as for kerosene (Figure 11). The change in markets for residual fuel in particular has had a large impact on refinery operations in the region. Those refineries unable to convert residual fuel to other products have suffered from the inability to match their product slate to market requirements. In some cases, overall production has been constrained because of an inability to sell the residual oil fraction.

Regional demand for asphalt and road oil has declined somewhat since peaking in the early 1970's, but has been reasonably stable (Figure 10). Miscellaneous products (Figure 12) have been somewhat less stable.

It is clear from the product histories that continuation of these trends into the future would make it unattractive to produce any product competing with residual fuel oil. Only gasoline, jet fuel and asphalt appear to be on stable or rising demand trends.

Specifications

Definitions

The terminology used for petroleum products is not always consistent and is sometimes confusing. Most major distinctions are made on the basis of boiling point. As generally used, gasoline is the lowest boiling fraction; it will be 10 percent distilled at 122-158 °F and 90 percent distilled at 365-374 °F.

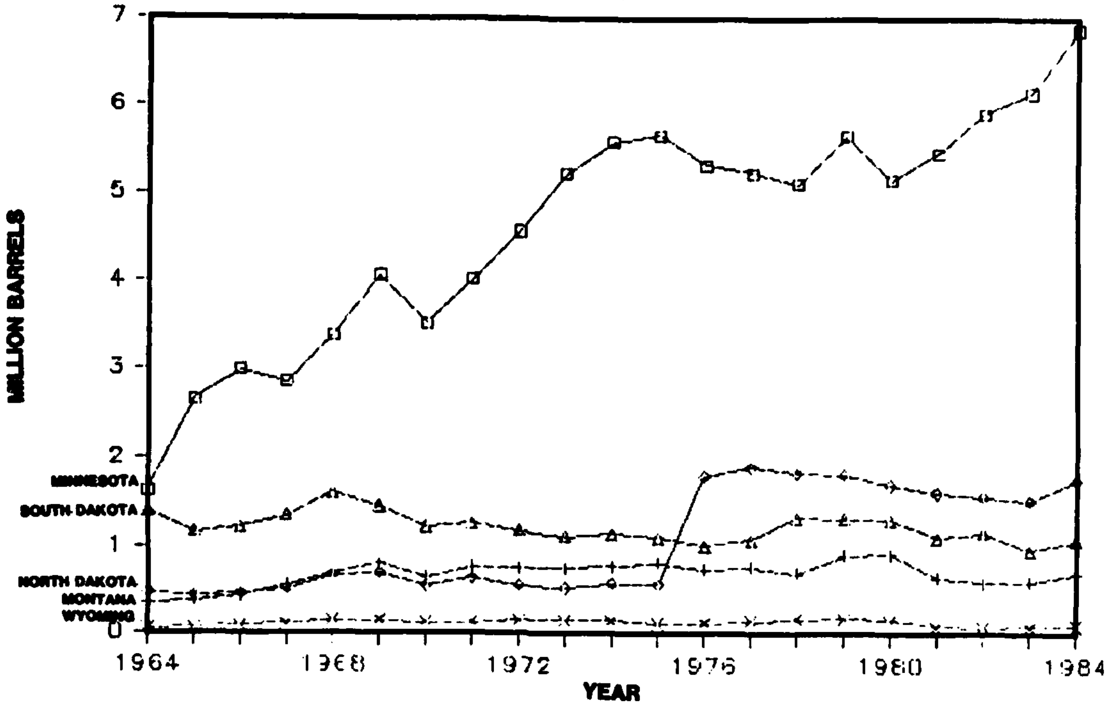


FIGURE 4

JET FUEL DEMAND

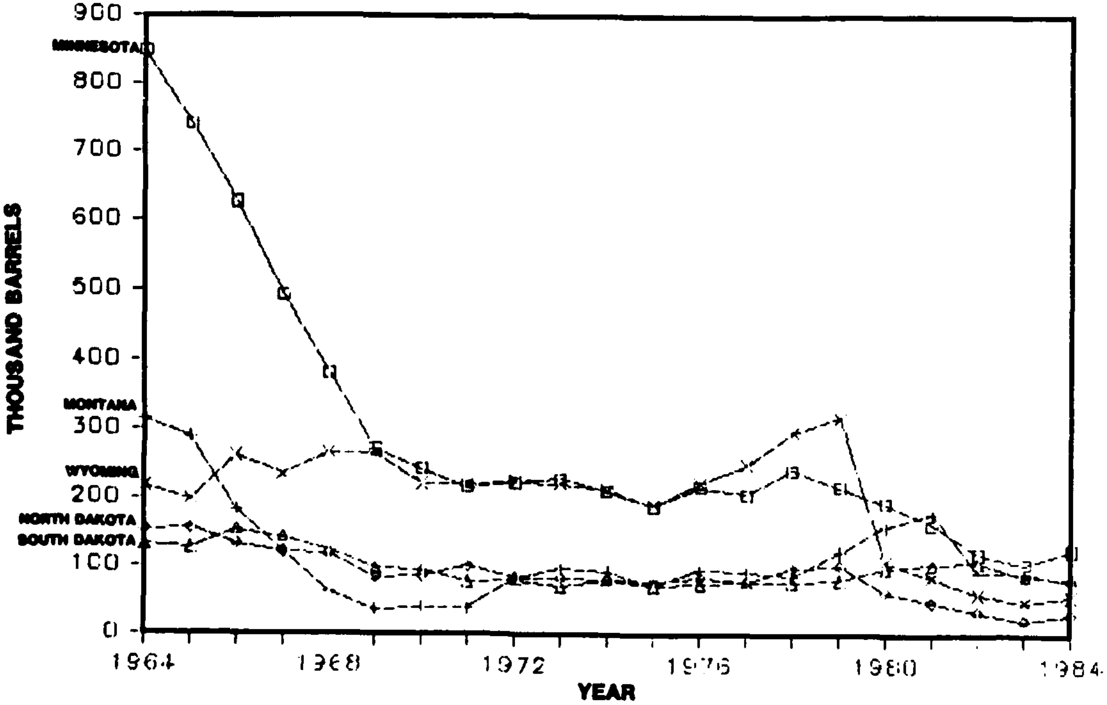


FIGURE 5

AVIATION GASOLINE DEMAND

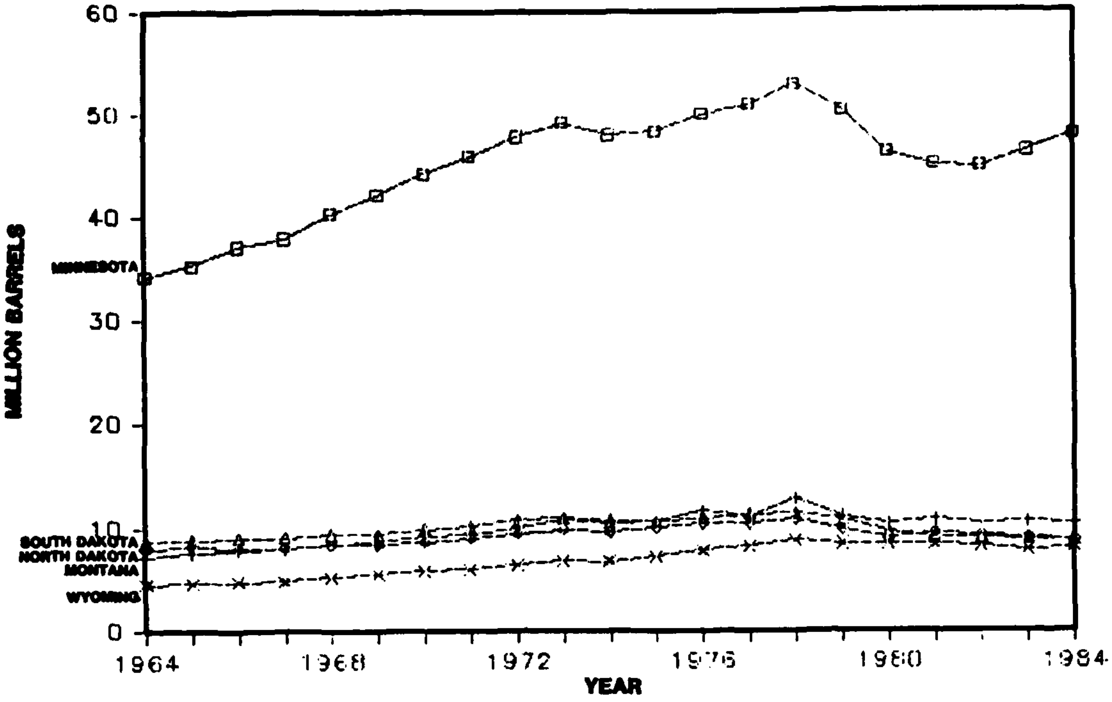


FIGURE 6

MOTOR GASOLINE DEMAND

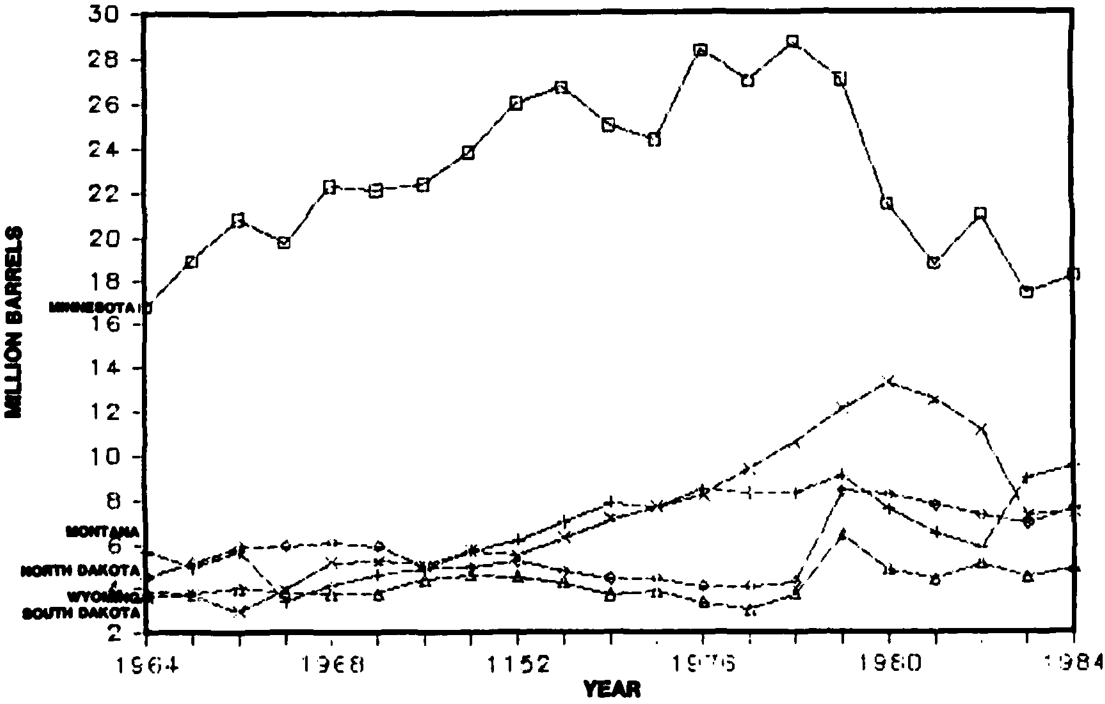


FIGURE 7

DISTILLATE FUEL DEMAND

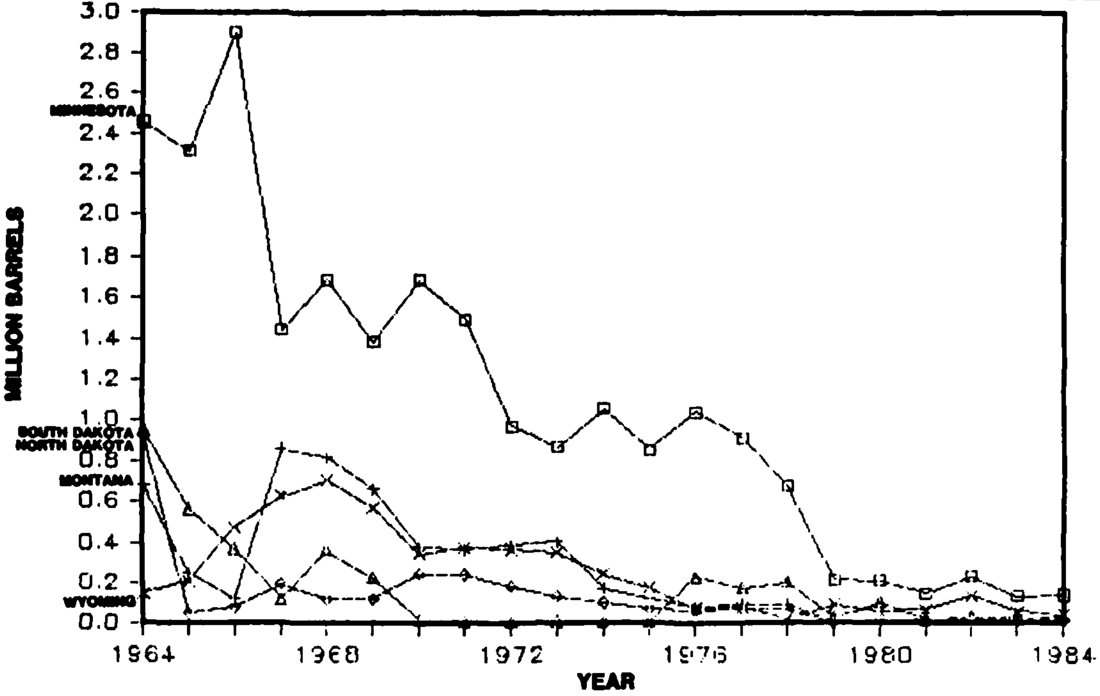


FIGURE 8

KEROSENE DEMAND

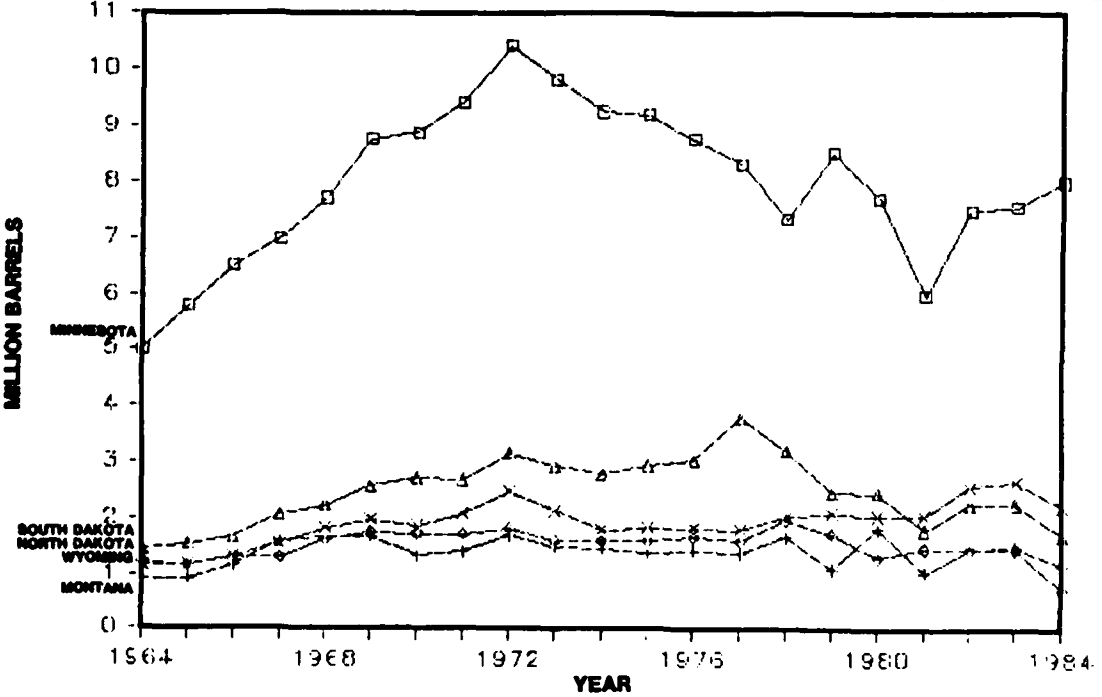


FIGURE 9

LPG DEMAND

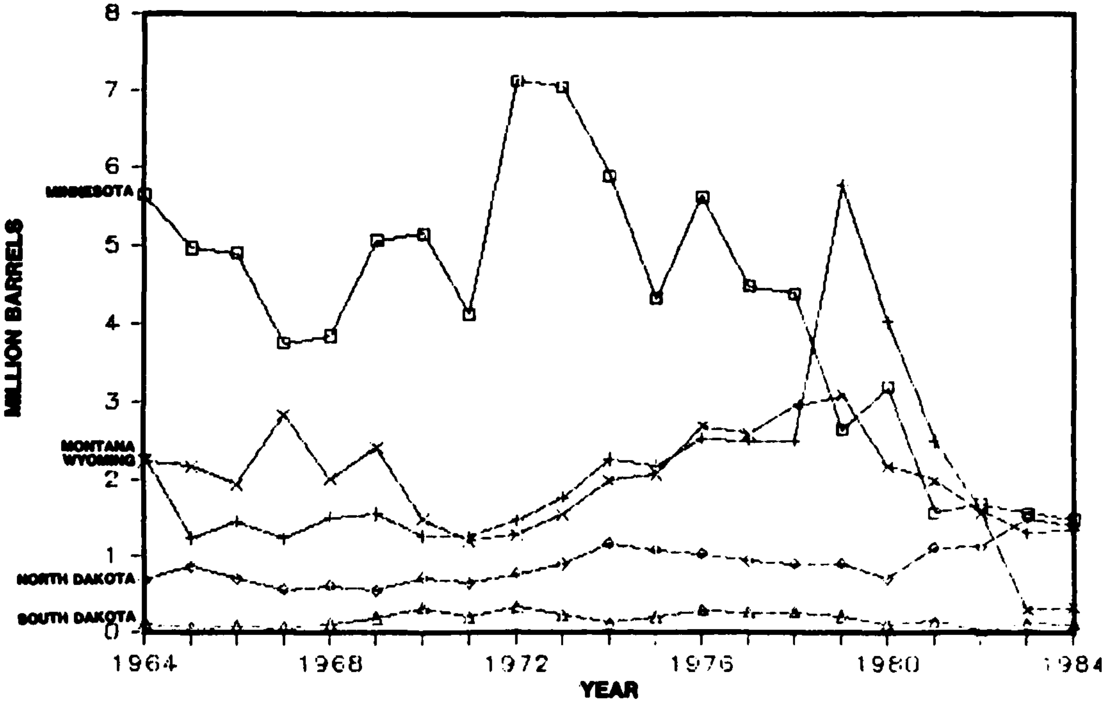


FIGURE 10

ASPHALT & ROAD OIL DEMAND

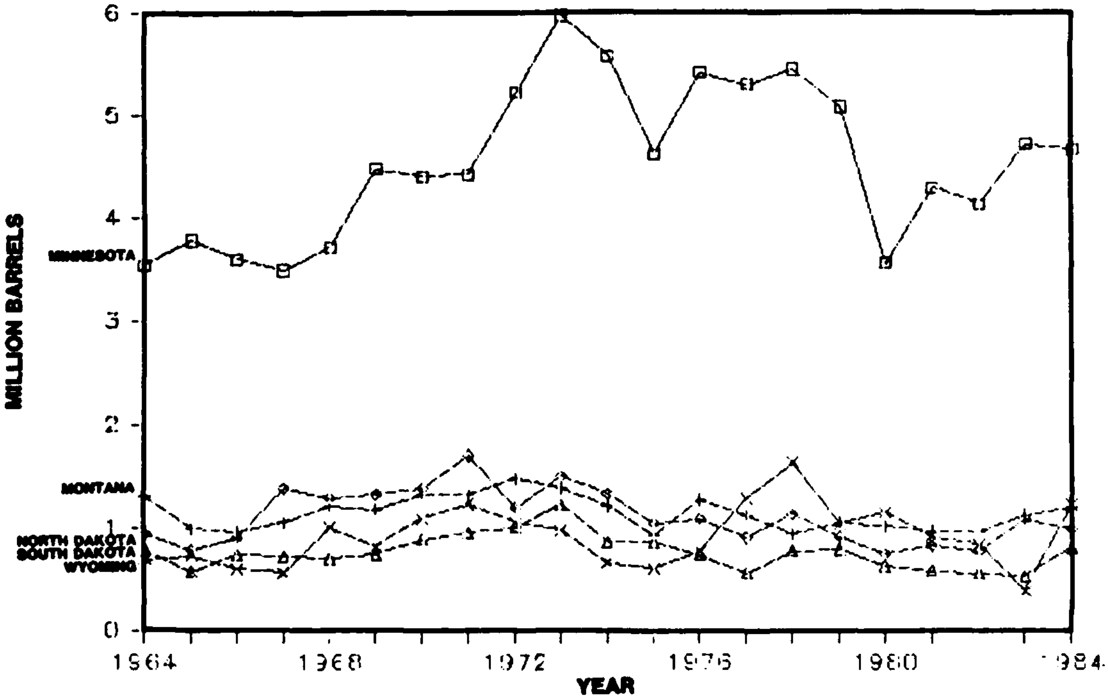


FIGURE 11

RESIDUAL FUEL DEMAND

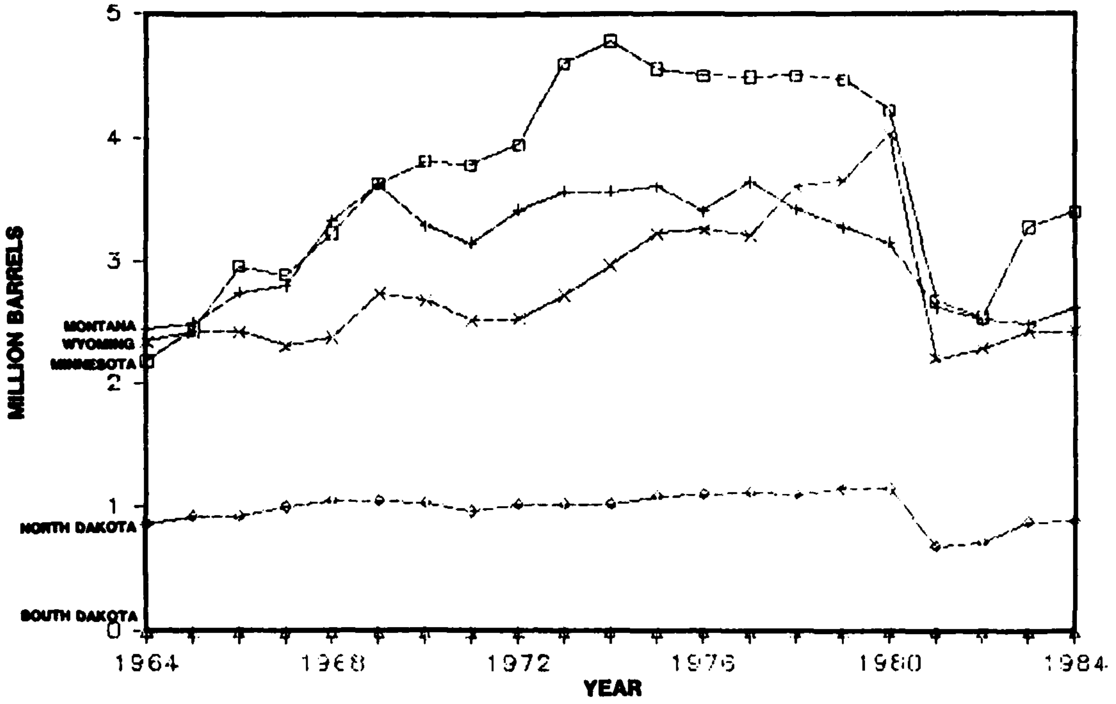


FIGURE 12

OTHER PETROLEUM PRODUCTS DEMAND

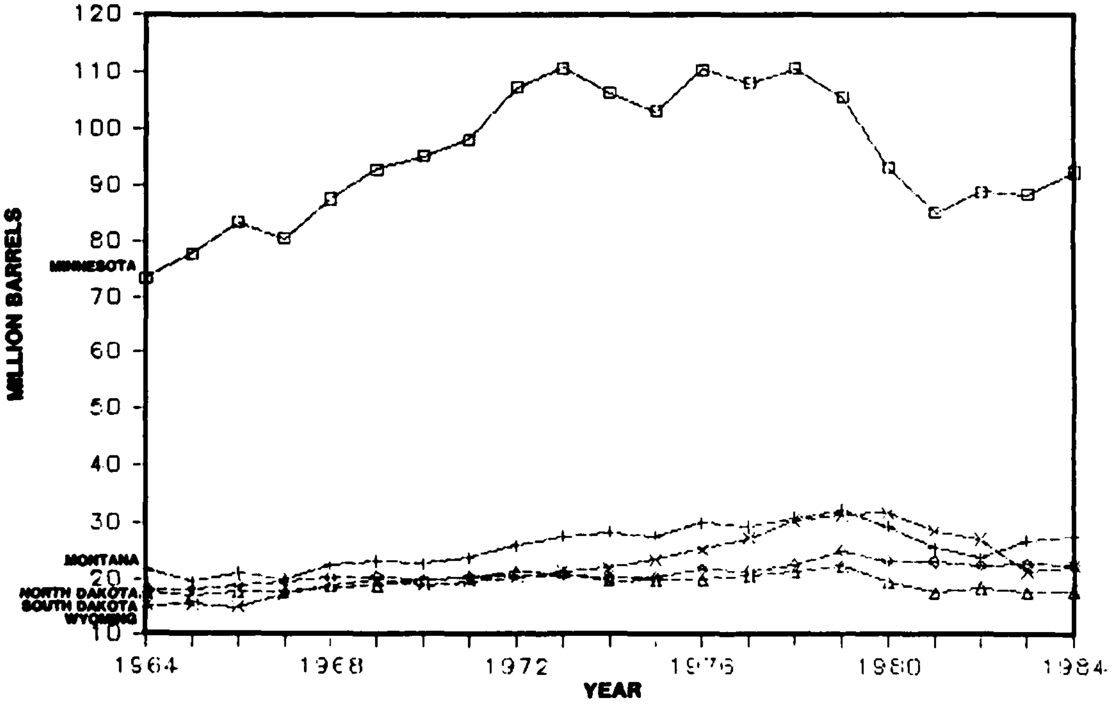


FIGURE 13

TOTAL PETROLEUM PRODUCTS DEMAND

After gasoline, the next boiling fraction is usually defined as naphtha. In an alternative definition, the naphtha boiling range includes gasoline, which is referred to as refined petroleum naphtha. Within a refinery, naphtha is a process intermediate; it is commonly fed to a steam reformer to make additional gasoline blending components. In this usage, naphtha may refer to a stream boiling above gasoline and up to 500 or even 600 °F endpoint. "Light naphtha" may have an endpoint of 400 °F. When prepared as a finished product, "naphtha" denotes a more specific type of product with a narrow boiling range. Here the terms "solvent" and "naphtha" are often used interchangeably. Specialty naphthas may have endpoints as low as 220 °F.

Kerosene is usually considered to have a boiling range higher than naphtha, such as 300-550 °F. Thus a kerosene-type jet fuel may have a 20 percent distilled point of 400 °F, compared to a 20 percent distilled point of 293 °F for a naphtha-type jet fuel. The allowable end points are not so far apart; thus the naphtha-type fuel may be called a "wide-cut" fuel.

The term distillate of course embraces any material which comes overhead in an atmospheric distillation column. The bottoms from the column are residual fuel. Light distillate may refer to gasoline and light naphtha. Middle distillate includes kerosene and the distillate fuel oils, whereas gas oil includes only the fuel oils. The term gas oil descends from when this fraction was used to make illuminating gas.

The distillate fuel oils include #1, #2, and #4 heating oils, and #1, #2 and #4 diesel fuel. However, #4 fuel oil may be made by blending residual fuel with varying proportions of distillate. Thus #4, #5 and #6 are termed "black oils," while #1 and #2 are "white oils."

Grade #1 fuel oil is designed for use in vaporizing pot-type burners, while #2 fuel oil is designed for use in atomizing type burners for domestic heating or moderate capacity commercial/industrial burner units. Grade #4 fuel oil is intended for commercial burner installations not equipped with fuel preheating facilities. It is used extensively in industrial plants.

Diesel fuels are distillate fuels for use in compression-ignition engines. Diesel #1 is for use in high-speed diesel engines generally operated under variations in speed and load. It includes type C-B diesel fuel used for city buses and similar operations. Diesel #2 is a lower volatility fuel, designed for high-speed diesel engines which are operated under generally uniform load and speed. It includes type R-R for railroad locomotive engines and type T-T for trucks. A #4 diesel is intended for low and medium-speed diesel engines.

Residual fuel, which includes #5 and #6 fuel oil, and Bunker C fuel oil, is used for the production of electric power, industrial steam generation, vessel bunkering, large commercial heating systems, and various other industrial purposes.

Jet Fuel

Jet fuel specifications were presented earlier. Specifications provide limits on certain parameters. It is also of interest to know how close the fuels actually being marketed come to those limits. Table 20 presents the results of the fuels testing program carried out at the National Institute for Petroleum

TABLE 20

AVERAGE JET FUEL PROPERTIES IN THE UNITED STATES

	JP-4	JET-A	JP-5
Type	Naphtha	Kerosene	Kerosene
Gravity, °API	54.7	42.2	41.0
RVP, psi	2.6	-	-
Freeze Point, °F	-82	-50	-54
ASTM D86 Distillation Percent Overhead			
10%	195	369	387
50%	277	414	417
90%	378	472	462
Aromatic Content, Vol%	12.3	17.8	18.8
Olefin Content, Vol%	0.8	1.1	0.7
Heat of Combustion, Net, BTU/lb	18,706	18,698	18,504

Source: Bartlesville Energy Technology Center, 1986

and Energy Research (NIPER). The average aromatics content of JP-4 is well below the specification value of 20 percent.

Gasoline

Motor Gasoline is a complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, that have been blended to form a fuel suitable for use in spark-ignition engines. Specifications for motor gasoline, as given in ASTM Specification D439 or Federal Specification VV-G-1690B, include a boiling range of 122-158 °F at the 10 percent point to 365-374 °F at the 90 percent point and a Reid vapor pressure range from 9 to 15 psi. "Motor gasoline" in the past included finished leaded gasoline, finished unleaded gasoline, and gasohol. However, leaded gasoline will be eliminated in the future.

Gasoline properties are changed from summer to winter as a function of the prevailing temperature. Table 21 shows the summer/winter variation for the district in which the Great Plains plant is located.

Kerosene

Kerosene is defined as a petroleum distillate that boils at a temperature between 300-500 °F, that has a flash point higher than 100 °F by ASTM Method D56, that has a gravity range from 40-46 degrees API, and that has a burning point in the range of 150-175 °F. Included are the two classifications recognized by ASTM D3699: #1-K and #2-K, and all grades of kerosene called range or stove oil which have properties similar to #1 fuel oil, but with a gravity of about 43 degrees API and a maximum end-point of 625 °F. Kerosene is used in space heaters, cook stoves, and water heaters and is suitable for use as an illuminant when burned in wick lamps.

Diesel Fuel

Diesel fuel #1 and #2 specifications are given by ASTM Specification D975. These specifications are listed in Table 22. By comparison, the average properties of #1 and #2 diesel fuel sold in the Great Plains region are given in Table 23.

Fuel Oil

The specifications for #1 and #2 fuel oil are basically the same as for #1 and #2 diesel fuel (ASTM D975). Average properties of #1 and #2 fuel oils sold in the Great Plains region are given in Table 24.

ASTM D396 specifications for #4, #5 and #6 fuel oils (including #4 diesel) are listed in Table 25. Very little #4 and #5 fuel oil is sold in the Great Plains region. Average properties of #6 fuel oil sold in the region are given in Table 26.

Summary

All petroleum products are sold to a set of specifications which have been developed through a marriage of consumers' needs and refiners' capabilities. A simple distillation of lignite tar oil would not produce any products

TABLE 21

AVERAGE UNLEADED MOTOR GASOLINE PROPERTIES IN GREAT PLAINS REGION
(NIPER District 9)

	Regular Summer/Winter (R+M)/2 Below 90	Premium Summer/Winter (R+M)/2 Above 90
Gravity, °API	60.1/62.9	59.4/54.6
Sulfur, Wt%	0.023/0.029	0.017/0.009
Benzene, Vol%	-	-
RON	91.6/91.5	95.9/96.7
MON	83.4/83.6	87.8/88.6
(R + M)/2	87.5/87.6	91.8/92.7
RVP, psi	11.3/14.7	11.1/14.7
ASTM-D86 Distillation, Temp, °F		
Initial Boiling Point	83/78	81/71
5 % Overhead	99/86	99/79
10%	115/100	123/98
20%	138/120	151/128
30%	161/143	182/161
50%	209/195	228/211
70%	257/249	262/241
90%	333/333	331/307
95%	368/372	362/353
End Point	414/420	415/408
Residue, Vol%	0.9/0.8	1.0/1.0

Source: Bartlesville Energy Technology Center, 1986

TABLE 22

SUMMARY OF REQUIREMENTS FOR DIESEL FUELS

Grade	No. 1-D	No. 2-D	No. 4-D
Flash Point °F, Min	38	52	55
Carbon Residue On 10% Residual, Percent, Max	0.15	0.35	-
Ash Wt%, Max	0.01	0.01	0.10
Distillation Temp To Give 90% Overhead,			
Min	-	282	-
Max	288	338	-
Kinematic Viscosity cSt At 40 °C			
Min	1.3	1.9	5.5
Max	2.4	4.1	24.0
Sulfur Wt%, Max	0.50	0.50	2.0
Cetane No., Min	40	40	30

Source: ASTM D-975

TABLE 23

TYPICAL PROPERTIES OF DIESEL FUELS IN THE GREAT PLAINS REGION
(NIPER Central Region)

	No. 1-D		No. 2-D	
	Low	High	Low	High
Gravity, °API	41.0	44.6	29.8	40.8
Flash Point, °F	127	169	137	201
Cloud Point, °F	-26	-26	-14	24
Sulfur, Wt%	0.0	0.3	0.100	0.415
Ash, Wt%	0.001	0.008	0.000	0.010
Cetane No.	45.5	47.0	37.8	54.7
Distillation				
Initial Boiling Point	288	393	315	429
10% Overhead	365	412	389	485
50% Overhead	408	452	485	544
90% Overhead	468	510	556	632
End Point	494	545	594	677

Source: Bartlesville Energy Technology Center, 1986

TABLE 24

AVERAGE NO. 1 AND NO. 2 FUEL OIL PROPERTIES FOR THE GREAT PLAINS REGION

(NIPER Central Region)

	No. 1	No. 2
Gravity, °API	42.4	34.1
Viscosity, 100°F, Centistokes	1.64	2.71
Sulfur, Wt%	0.129	0.260
Aniline Point, °F	130.9	127.7
Carbon Residue, Wt%	0.081	0.127
Gross Heat of Combustion, MBTU/Gal	134.3	139.2
ASTM Distillation, °F		
Initial Boiling Point	345	367
10%	382	427
50%	429	509
90%	489	598
End Point	530	647

Source: Bartlesville Energy Technology Center, 1986

TABLE 25

SPECIFICATIONS FOR RESIDUAL FUEL OILS

Grade Of Fuel Oil	Flash Point, °F Min	Pour Point, °F Max	Water and Sediment, Vol% Max	Ash, Weight% Max	Kinematic Viscosity cSt at 100°F Min	Kinematic Viscosity cSt at 100°F Max	Sulfur %
No. 4 Preheating not usually required	130	20	0.50	0.10	5.8	26.4[A]	legal
No. 5 (Light) Preheating may be required	130	-	1.00	0.10	26.4	65[A]	legal
No. 5 (Heavy) May need preheating for burning; and in cold climates, for handling	130	-	1.00	0.10	65	194[A]	legal
No. 6 Preheating required for burning and handling	130	B	2.00	-	-	-	legal

[A] Where low sulfur oil is required, fuel oil falling in the viscosity range of a lower numbered grade down to and including No. 4 may be supplied by agreement between purchaser and supplier.

[B] Where low sulfur fuel oil is required, Grade 6 fuel oil will be classified as low pour, 15 degrees C (60°F) max, or high pour (no max). Low pour fuel oil should be used unless all tanks and lines are heated.

TABLE 26

AVERAGE NO. 6 FUEL OIL PROPERTIES IN THE GREAT PLAINS REGION

(NIPER Central Region)

Gravity °API	11.6
Sulfur, Wt%	0.86
Ash, Wt%	0.010
Gross Heat Of Combustion (MBTU/Gal)	153.4

Source: Bartlesville Energy Technology Center, 1986

matching existing specifications. However, modern refining processes are available to modify the characteristics of hydrocarbon streams almost at will. Large molecules can be cracked and small molecules can be combined. Unsaturated compounds can be hydrogenated and saturated compounds can be dehydrogenated. Ring compounds can be cracked and linear compounds can be reformed into rings. Thus there is no doubt that, with sufficient processing, the Great Plains liquids could be formed into specification fuels.

Most fuel specifications are stated in terms of physical properties rather than chemical composition. Thus there is no inherent barrier to the use of coal-derived liquids. The major exceptions are limits on aromatics content for jet fuels and a proposed similar limit for diesel fuels. Although aromatics in diesel fuel are not currently limited by specification they lower the cetane number and are undesirable for that reason. The high aromatics content of the Great Plains liquids would have to be modified for these applications.

Prices

Prices paid for petroleum products in the Great Plains region over the last four years are summarized in Tables 27 through 32. The generally small differences in prices between states attests to the efficiency of the United States petroleum products distribution system and to the keen competition between refineries. As would be expected, prices are slightly higher in Minnesota, which is a product importer, than in Wyoming, which is a product exporter.

In a number of cases there are not enough sales of a particular fuel in some states of this region to form a statistical base. For this reason, the Petroleum Administration for Defense District (PADD) averages have been included in Tables 27 through 32. PADD definitions are shown in Figure 14. It is unusual to see a spread of more than three or four cents per gallon in fuel prices between states, which corresponds to the cost of moving fuel about 150 miles by truck.

Market Outlook

It is unlikely that petroleum products in general will again show the large year-to-year increases in demand which were common prior to the price shocks of the 1970's. However, gasoline, the largest volume product, could be poised to show some gain in volume. The federally mandated increases in Corporate Average Fuel Economy have reached their legislated limits. Average automobile mileage will continue to increase for some time as new cars replace older less-efficient cars on the road. The average mileage for new automobiles, however, is unlikely to increase from present levels. Gasoline demand should therefore be fairly stable in the future.

Commercial jet fuel is expected to show continued gains in demand. The restructuring of labor rates in the airline industry has dropped fares to the point where they are stimulating increased travel. As consumer desires for goods such as autos, home appliances and electronics becomes sated, there appears to be an almost unlimited desire for travel.

Kerosene is an obsolete product with little chance of revival.

TABLE 27

SALES FOR RESALE PRICES
OF UNLEADED GASOLINE

(Cents Per Gallon Excluding Taxes)

	1983	1984	1985	1986
Padd II Average	93.0	85.0	89.6	49.13
Minnesota	95.5	86.8	91.0	50.1
North Dakota	95.6	86.2	91.5	48.9
South Dakota	95.6	84.5	90.8	47.3
Padd IV Average	91.2	86.7	90.3	50.4
Montana	89.3	85.3	89.3	53.0
Wyoming	92.5	90.0	90.4	47.7

TABLE 28

SALES FOR RESALE PRICES
OF KEROSENE-TYPE JET FUEL

(Cents Per Gallon Excluding Taxes)

	1983	1984	1985	1986
Padd II Average	89.7	86.1	82.6	45.9
Minnesota	-	82.9	85.3	47.7
North Dakota	-	94.8	-	-
South Dakota	-	95.6	93.5	-
Padd IV Average	90.9	88.2	83.3	50.7
Montana	-	87.7	-	-
Wyoming	-	95.0	94.7	-

TABLE 29

SALES FOR RESALE PRICES OF KEROSENE

(Cents Per Gallon Excluding Taxes)

	1983	1984	1985	1986
Padd II Average	96.0	91.8	95.7	54.8
Minnesota	-	93.8	100.9	55.5
North Dakota	-	-	-	-
South Dakota	-	-	-	-
Padd IV Average	90.9	90.9	93.0	54.4
Montana	-	-	-	-
Wyoming	-	-	-	-

TABLE 30

SALES FOR RESALE PRICES OF NO. 1 DISTILLATE

(Cents Per Gallon Excluding Taxes)

	1983	1984	1985	1986
Padd II Average	92.1	87.2	94.0	50.6
Minnesota	-	89.0	95.7	52.9
North Dakota	-	90.6	96.0	53.0
South Dakota	-	89.6	95.1	51.9
Padd II Average	91.2	90.1	91.0	50.8
Montana	-	91.2	91.6	50.4
Wyoming	-	90.8	90.9	50.9

TABLE 31

SALES FOR RESALE PRICES OF NO. 2 DISTILLATE

(Cents Per Gallon Excluding Taxes)

	1983	1984	1985	1986
Padd II Average	86.4	81.9	87.9	44.9
Minnesota	87.9	83.1	89.3	47.9
North Dakota	87.7	-	-	-
South Dakota	87.6	-	-	-
Padd IV Average	84.4	83.7	83.9	46.2
Montana	83.9	-	-	-
Wyoming	84.1	-	-	-

TABLE 32

SALES FOR RESALE PRICES OF RESIDUAL FUEL

(Cents Per Gallon Excluding Taxes)

	1983	1984	1985	1986
Padd II Average	62.4	62.4	52.9	28.7
Minnesota	-	56.9	-	-
North Dakota	-	-	-	-
South Dakota	-	-	-	-
Padd IV Average	59.3	57.8	52.6	27.3
Montana	-	-	-	-
Wyoming	-	-	-	-

Diesel fuel demand is strongly linked to overall economic activity. Trucking, railroads, and construction all exhibit cyclic demand patterns which will continue in the future.

Heating oils are in a long-term decline due to loss of markets to natural gas. This loss is mostly irreversible.

Residual fuel is regaining some markets which were earlier lost to natural gas and coal. If oil prices rise even moderately, however, these markets will again be lost. This is because the differential price between crude oil and residual oil is considerably smaller than it was a few years ago. The differential has shrunk because more refiners have installed processes for converting residual fuel to higher-value products.

Because of strong competition in the petroleum refining industry, all refined product prices move in relationship to the price of crude oil. Because of the dominance of OPEC in supplying crude oil, world oil prices are set not by competitive supply and demand, but by OPEC policy. Price projections for oil products therefore amount to projections of OPEC policy. If oil demand were to decline below present levels, OPEC would lose its power to dictate prices. But with even a modest increase in demand, and the drop-off in non-OPEC production which is occurring at early 1987 price levels, OPEC's position clearly should strengthen. The forecast for this study, then, is that world oil prices will recover slowly, regaining 1985 levels (in constant dollars) by 1992, and 1980 levels by the year 2010.

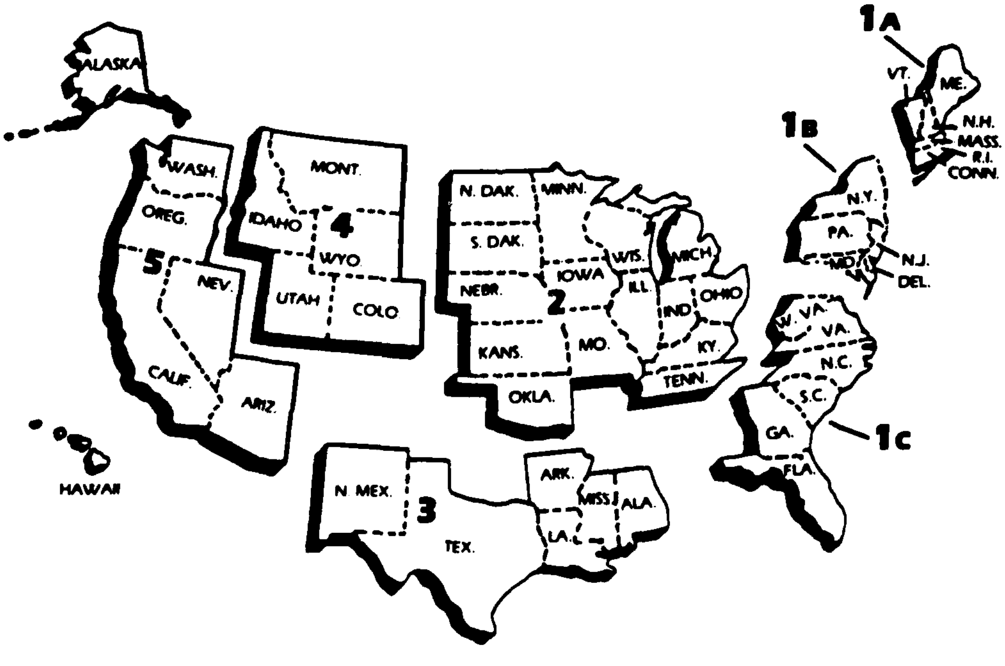


FIGURE 14

PETROLEUM ADMINISTRATION FOR DEFENSE (PAD) DISTRICTS

REFINERY FEEDSTOCK

A number of properties of the Great Plains tar oil make it undesirable as a refinery feedstock. These include high levels of oxygen, nitrogen and particulates. Conventional refineries would be unable to accept the tar oil as feedstock unless blended down to very low concentrations. The configurations of refineries in the Great Plains region were evaluated to determine their hydrotreating capabilities. Table 33 lists the refineries in the defined market area, and their hydrotreating capabilities. As used in the table, hydrocracking includes those processes where 50 percent or more of the feed is reduced in molecular size. In hydrorefining, 10 percent of the feed or less is reduced in molecular size; and for hydrotreating, essentially no reduction in molecular size of feed occurs. None of the refineries in the region have the capability to hydrotreat the whole crude stream, as would be required for tar oil. Only the Exxon refinery in Montana lists hydrocracking capability, and this is for distillate upgrading only.

There is, however, one interesting future possibility for direct sale of the tar oil stream as refinery feedstock. Consumers Cooperative Refinery in Regina, Saskatchewan is building a heavy oil upgrading system to allow it to process the very heavy oils of Saskatchewan and Alberta. The Canadian federal and provincial governments are providing financial aid to the project, which is being carried out by New Grade Energy, Inc., a partnership of Consumers Cooperative Refinery Ltd. and the Saskatchewan government. The 50,000 barrel per day project is expected to cost $650,000,000. Consumers Cooperative is providing 5 percent of the equity, and the provincial government 15 percent. The federal and provincial governments are providing loan guarantees for the remaining 80 percent of the cost as debt.

The project is well along in construction and should be finished next year (1988). Hydrocracking processing technology is provided by Unocal, with their Unicracking process. Unicracking carries out hydrodesulfurization and mild hydrocracking using a fixed catalyst bed. It is normally used to upgrade residual fuel oils and many vacuum resids by removing significant amounts of metals, sulfur, nitrogen and residual carbon. Feed and hydrogen-rich recycle gas are preheated, mixed, and fed to a guard chamber, where a small bed of catalyst removes particulate matter and residual salt. Effluent flows into one or more main reactors, which contain most of the catalyst. Liquid product is cooled, separated and sent to further processing.

According to Unocal, the major feedstream constraints are on oxygen, nitrogen and particulates. If the oxygen level is too high, the resulting partial pressure of water is deleterious. It destroys the catalyst support. The oxygen level of 2.7 percent in the Great Plains tar oil would be borderline acceptable. Because the total tar oil stream would amount to only about 6 percent of the total feed to the upgrader, however, oxygen content is not seen to be limiting.

Similarly, the maximum allowable nitrogen level to the hydrocracker is about 5,000 ppm. The Great Plains tar oil has a slightly higher level (6,000), but not enough higher to be a problem for blending.

The limiting factor is likely to be particulates. Because a fixed catalyst bed is used, Union specifies maximum particulates in the 2-5 parts per million range. Although good numbers are not available for the Great Plains tar oil, one analysis of sediment by extraction gave 0.1 weight percent. If this material were all particulates by Unocal's definition, it would be 1,000 ppm, or too high by two orders of magnitude. Some kind of filtration would have to be provided.

Consumers Cooperative currently brings in some crude oil from North Dakota and Montana, and the trans-border movement of feedstock is not seen to be a problem. Because of favorable government financing assistance, the NewGrade project will likely have a lower break-even point for operating margin than a conventionally financed hydrocracker. It should therefore be able to compete for feedstock on attractive terms. If reasonable transportation costs could be arranged with the railroads, this might provide an outlet for the Great Plains tar oil yielding a higher netback than sale as No. 6 fuel oil.

Two possible issues to be addressed are the strong odor associated with the naphtha and to a lesser extent, the tar oil stream and treatment of the wastewater streams. The refinery would want to be assured that those would not be problems.

TABLE 33

CATALYTIC HYDROTREATING CAPABILITIES OF REFINERIES IN GREAT PLAINS REGION

(Quantities In Barrels Per Stream Day)

Refinery	Crude Capacity	Hydro-Cracking	Hydro-Refining	Hydro-Treating
Manitoba				
No Refineries				
Minnesota				
Ashland	69,220	---	23,000	39,700
Koch	160,000	---	63,500	86,000
Subtotal	229,220	---	86,500	125,700
Montana				
Cenex	42,500	---	14,000	15,000
Conoco	50,000	---	---	41,500
Exxon	44,000	4,900	---	41,500
Montana	6,500	---	---	2,200
Subtotal	143,000	4,900	14,000	100,200
North Dakota				
Amoco	60,000	---	---	15,000
Subtotal	60,000	---		15,000
Saskatchewan				
Consumer's	40,000	---	---	9,000
Petro-Canada	13,000	---	---	---
Subtotal	53,000	---	---	9,000
South Dakota				
No Refineries				
Wyoming				
Amoco	41,000	---	---	7,100
Frontier	35,500	---	4,350	7,000
Little America	24,500	---	---	7,200
Mountaineer	400	---	---	---
Sinclair	54,000	---	10,000	14,000
Wyoming	13,500	---	---	---
Subtotal	170,189	---	14,350	51,050
Total	655,709	4,900	114,850	300,950

CREOSOTE

Definitions and specifications

Creosote may be loosely defined as the fraction of coal tar distillate boiling in the range 400°F to 650°F. It is sometimes referred to as "dead oil," indicating that it is the higher boiling fraction of the oil obtained by distilling coal tar. Rather than producing a virgin distillate in this range, creosote is often produced by blending various tar oil fractions.

The oils are blended to give creosotes conforming to certain user specifications. The major outlet for coal-tar creosote is for the preservation of timber. Although other fungicides have been increasingly used, coal-tar creosote has been the most widely used wood preservative. It is particularly effective in prolonging the life of wood that is used outdoors and in contact with the ground, or seawater or freshwater. Examples are telegraph and electricity transmission poles, railway ties, marine piling, fencing, and farm buildings.

To give these structures service lives of 50 years or more, they are impregnated under pressure with creosote so that the vulnerable sapwood cells are either filled with oil (by the Bethell or "full-cell" process generally used for marine piling and railway ties), or coated with a film of creosote (by the Rueping or Lowry "empty-cell" processes more generally used for poles, fencing, and farm buildings).

Other minor uses for creosotes are as horticultural washes to kill overwintering pests on fruit trees, and for making disinfectant emulsions and sheep dips.

Specifications for creosote for timber preservation are published by the American Wood Preservers' Association (AWPA). Standard P1-78 is the most widely used, general-purpose standard (Table 34). Standard P7-85 gives the requirements for a crystal-free product to protect cut surfaces of treated wood, and P13-85 specifies the properties of a marine grade creosote for piles and timbers (Table 35). Solutions of coal tar in creosote are covered in Standard P2-85 (Table 36). These solutions may be used in applications where the surface condition of the treated wood is not important. A marine grade creosote-coal tar solution, standard P12-85, gives better protection against marine borers than Standard P2-85. In general, the more severe the service, the higher the required specific gravity (Table 37).

As seen in Tables 34 through 36 the AWPA standards define creosote as a distillate of coal tar produced by the carbonization of bituminous coal. Thus the low-temperature lignite tar produced at the Great Plains plant is excluded a priori. Also, it probably would not meet the specific gravity specifications. Nevertheless, there is reason to believe that, from a performance standpoint, the Great Plains tar should be satisfactory. Low temperature lignite tars have been used successfully for wood preservation in the past. The existing specifications are wholly empirical; the requirements evolved through a compromise between the consumers' needs in timber preservation and the producers' processing capabilities and coal tar feedstocks.

TABLE 34

AWPA P1-78 (REVISED) STANDARD FOR COAL TAR CREOSOTE

The creosote shall be a distillate derived entirely from tar produced by the carbonization of bituminous coal.

	Not Less Than	Not More Than
Water, Percent By Volume	-----	1.5
Matter Insoluble In Xylene Percent By Wt	-----	0.5
Specific Gravity		
Whole Creosote	1.050	-----
Fraction 235-315 °C	1.027	-----
Fraction 315-355 °C	1.095	-----
Distillation: Percent By Wt On A Water-Free Basis:		
Up To 210 °C	-----	2.0
Up To 235 °C	-----	12.0
Up To 270 °C	10.0	35.0
Up To 315 °C	40.0	65.0
Up To 355 °C	60.0	77.0

TABLE 35

AWPA P13-85 STANDARD FOR COAL TAR CREOSOTE TO BE USED IN THE TREATMENT OF MARINE PILES AND TIMBERS

The creosote shall be a distillate derived entirely from tar produced by the carbonization of bituminous coal.

	Not Less Than	Not More Than
Water, Percent By Volume	----	1.5
Matter Insoluble In Xylene, Percent By Weight	----	0.5
Specific Gravity:		
Whole Creosote	1.080	----
Fraction 235-315 °C	1.090	----
Fraction 315-355 °C	1.105	----
Residue Above 355 °C	1.160	----
Distillation: Percent By Wt On A Water-Free Basis		
Up To 210 °C	----	2.0
Up To 235 °C	----	12.0
Up To 270 °C	20.0	40.0
Up To 315 °C	45.0	65.0
Up To 355 °C	65.0	75.0

TABLE 36

AWPA P2-85 STANDARD FOR CREOSOTE SOLUTIONS

The material shall be a pure coal tar product, derived entirely from tar produced by the carbonization of bituminous coal. It may be either a coal tar distillate or a solution of coal tar in coal tar distillate.

	Grade A		Grade B		Grade C		Grade D	
	Not Less Than	Not More Than	Not Less Than	Not More Than	Not Less Than	Not More Than	Not Less Than	Not More Than
Composition: Coal Tar Distillate Percent By Volume	80		70		60		50	
Water: Percent By Volume		3.0		3.0		3.0		3.0
Material Insoluble In Xylene: Percent By Weight		2.0		3.0		3.5		4.0
Coke Residue: Percent By Weight		5.0		7.0		9.0		11.0
Specific Gravity								
Whole Material	1.06	1.11	1.07	1.12	1.08	1.13	1.09	1.14
Fraction 235/315 °C	1.025		1.025		1.025		1.025	
Fraction 315/355 °C	1.085		1.085		1.085		1.085	
Distillation By Weight On A Water Free Basis:								
Up To 210 °C		5		5		5		5
Up To 235 °C		25		25		25		25
Up To 315 °C	36		34		32		30	
Up To 355 °C	60		56		52		48	

TABLE 37

SPECIFIC GRAVITY OF AWPA CREOSOTE GRADES

Standard	Specific Gravity
P1 Coal Tar Creosote	1.05
P2 Creosote Solutions	1.06
P7 Creosote For Field Cuts	1.06
P13 Creosote For Marine Piles	1.08
P12 Creosote Solution For Marine Piles	1.09

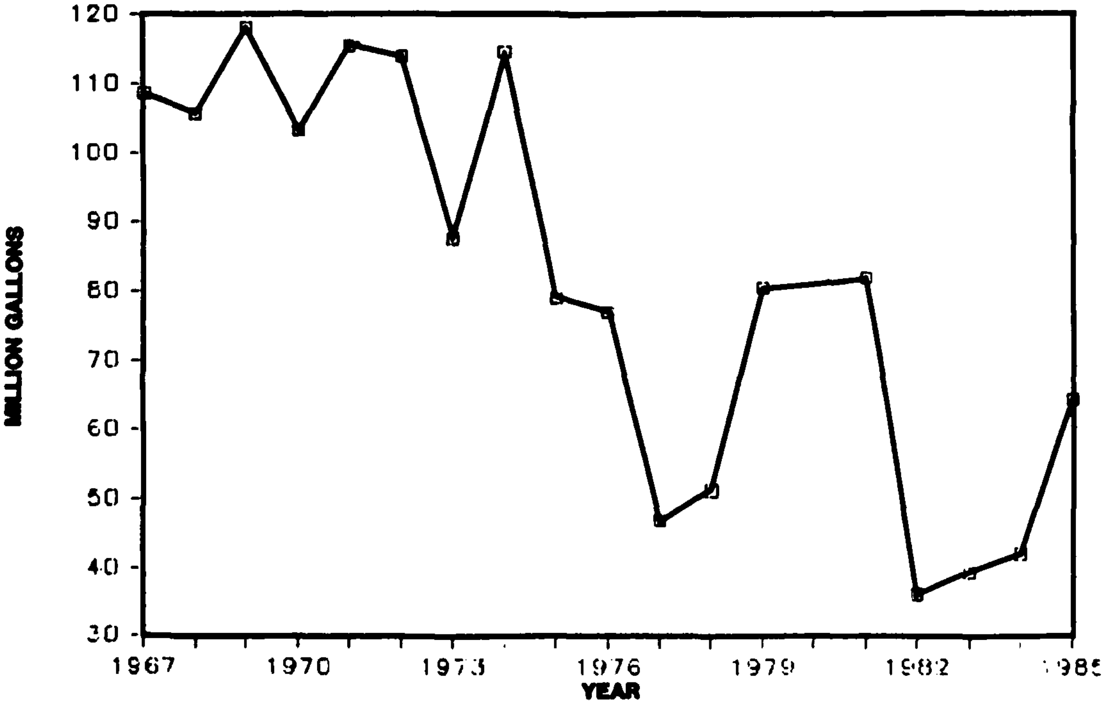


FIGURE 15

CREOSOTE PRODUCTION

Some users are willing to utilize material which does not meet AWPA specifications. Concrete evidence of this is provided by previous sales of the Great Plains material and by a long history of sales of creosote from the Lurgi low-temperature lignite carbonization plant operated by Husky Industries in Dickensen, North Dakota (this plant was shut down in 1986 because of environmental problems, but had operated since 1926). The Husky plant reopened January 1987 with a Nichols hearth furnace which does not produce by-product liquids.

The most likely near-future method of utilization would be as a blend with normal creosote. AWPA Standard P3-67 "Standard for Creosote-Petroleum Oil Solution" allows for blending up to 50 percent petroleum-derived oil with creosote for some applications. Some western railroads but not eastern, are known to use creosote-petroleum oil solutions. The Great Plains creosote should definitely have better preservative effect than petroleum oils. The availability of a large, secure supply of lignite creosote from the Great Plains plant may promote evolution of the AWPA specifications, as well as acceptance by consumers. However, considerable testing by the AWPA and industrial users would be necessary to demonstrate satisfactory performance. Product sold to date by Great Plains has been found unsatisfactory because of the odor.

Production

United States production of creosote for the years 1967 to 1985 is shown in Figure 15. A significant decline on the order of 50 percent has occurred since 1974. Historically, total consumption has been anywhere from 10 to 30 percent higher than production due to net imports from Europe. The quantity imported varies readily with currency exchange fluctuations. A small amount of creosote has been exported to Canada.

Prices

Historical creosote prices, as quoted in the Chemical Marketing Reporter, are presented in Figure 16. Prices were stable at $0.24 to $0.27 per gallon from 1960 to 1973. They than began to climb rapidly, reaching a peak of just under $1.20 per gallon. Although these are prices quoted for bulk quantities, we find that they do not represent prices which might be expected for large scale contract sales. Such prices have dropped significantly in the last year, from approximately $1.00 per gallon to $0.80 per gallon. These prices are for specification grade creosote delivered to the buyer's plant. The last price received by the Husky carbonization plant in North Dakota for its non-specification low-temperature lignite creosote was $0.60 per gallon.

Consumers

The locations of individual creosote treating plants listed by the American Wood Preservers' Institute are shown in Figure 17. These plants are concentrated in the Southeastern United States, perhaps because of the combination of a large timber industry in the region, plus a humid climate which makes timber preservation necessary for long life. Some of the largest purchasers of creosote are Kerr-McGee and Southern Wood Piedmont. It is estimated that these two companies each use around eight million gallons per year, or about 10 percent of the total demand, each. Almost all of this usage is for railroad ties.

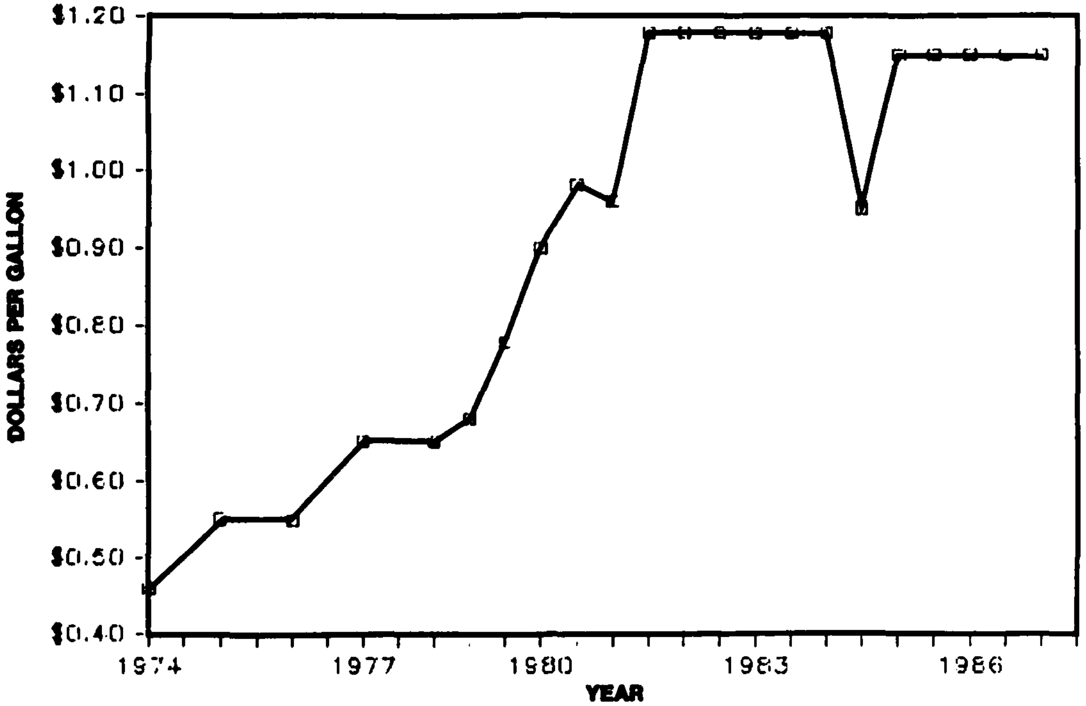


FIGURE 16

CREOSOTE PRICES
TANKS, WORKS, FAB

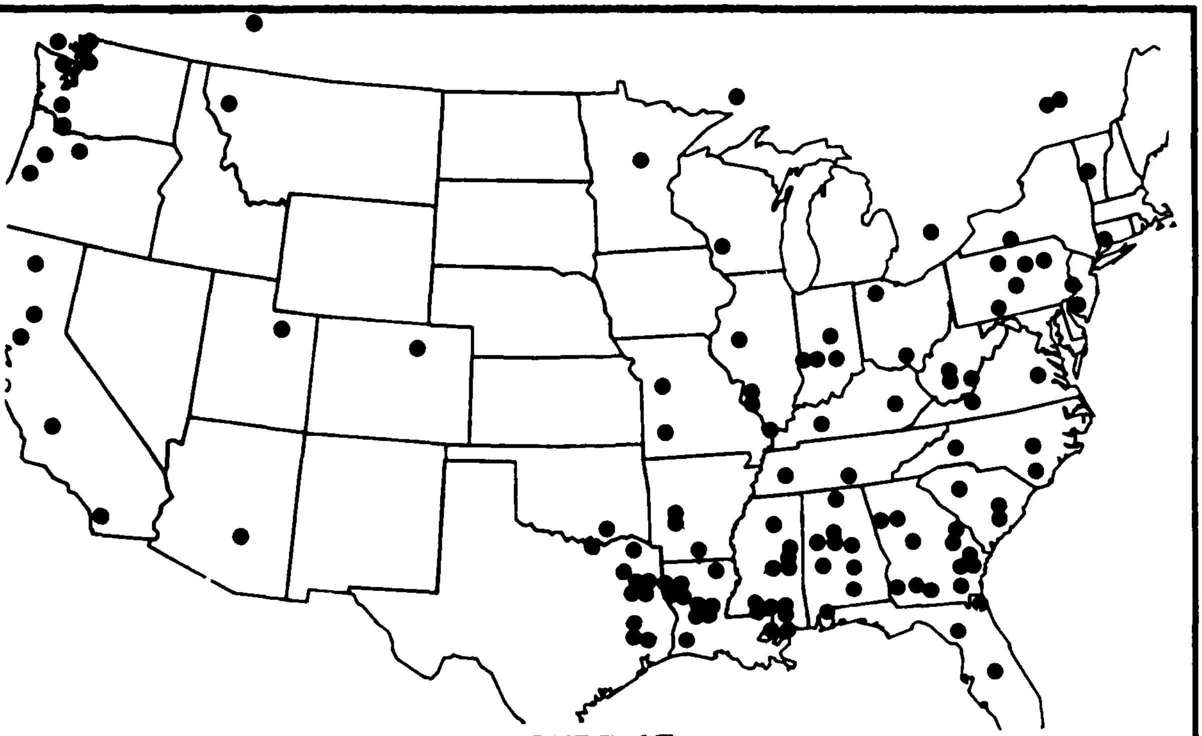


FIGURE 17

WOOD PRESERVERS USING CREOSOTE

On an industry-wide basis, over 65 percent of creosote usage is for railroad ties (Table 38). The data in Table 38 refer only to cubic feet of wood treated, without regard to the treatment procedure. Because railroad ties are always pressure-treated and other materials may not be, the fraction of total creosote usage accounted for by railroad crossties is higher than suggested in Table 38.

The most recent data available (1984) from the American Wood Preservers Institute show that total creosote usage in that year consisted of 41 million gallons of creosote and 61 million gallons of creosote-coal tar solutions.

Producers

Producers of creosote listed by the International Trade Commission include:

- Allied Corporation
- Reilly Tar and Chemical
- Koppers Company
- United States Steel Corporation
- Witco Chemical Corporation
- Coopers Creek Chemical Corporation

TABLE 38

CREOSOTE-TREATED WOOD PRODUCTS
(1984 Statistics)

Product	Cubic Feet	Percent Total
Railroad Crossties	88,720	65
Switch & Bridge Ties	8,198	6
Poles	22,639	16
Piling	6,850	5
Fence Posts	1,675	1
Lumber	3,892	3
Timbers	4,179	3
Other	1,441	1
	137,594	100

Source: International Statistics Council, 1986

Market structure

The creosote market is dominated by railroad requirements for crossties. Railroads who operate their own tie-treating facilities normally purchase creosote on the basis of delivery anywhere on their rail system. They than provide transportation to their tie treating plant.

Tie treating plants have encountered serious environmental problems over the last few years. Some railroads, Burlington Northern for one, will contract for treated ties rather than operate their own plants.

The largest volumes of creosote are purchased on once-a-year solicitations issued by the major consumers. Some operators of tie-treating facilities have their own captive sources of creosote. Some is marketed by middle-men, or independent brokers at fees of up to 10 percent of the purchase price.

Market Outlook

Overall consumption of creosote for wood preservation has declined slowly over the last 30 years while the use of water-borne preservatives has grown strongly (Figure 18). Creosote usage has been sustained by the demand for railroad crossties, for which creosote has been the only accepted preservative.

The introduction of concrete crossties has taken away some market share, although not a significant share to date. Because of environmental and health hazard concerns, it is very unlikely that creosote demand will show appreciable growth in the future. The market is vulnerable to replacement by concrete crossties or improved water-borne preservative compounds. Meanwhile, the continuing consolidation of railroad trackage systems is reducing the total market potential for replacement crossties. Past and estimated future demand for creosote-treated crossties, as prepared by the Railway Tie Association, are shown in Figure 19. A significant decline from recent demand levels is expected. Furthermore, the Railway Tie Association's projections do not consider increasing use of concrete ties. An Australian-American joint venture has recently begun to build a facility in Denver to manufacture some 3.5 million concrete ties for the Burlington Northern railroad by 1992. Because concrete ties cannot be intermingled with wood ties, market penetration will be limited in the near future.

If uses other than crossties and pilings were eliminated, demand could drop below 40 million gallons per year. Assuming that lignite-derived creosote would not be used at over 50 percent concentration, there would be a maximum market potential of 20 million gallons or 175 million pounds per year. Potential creosote production from the Great Plains plant is 128 million pounds per year. Thus, disposing of all Great Plains heavy oil as creosote would require capturing 73 percent of the potential long-term market in the United States. Canadian markets would expand the potential but not greatly. The Canadian market is estimated at less than 10 percent of the United States market. It may be concluded that the Great Plains creosote would have to be deeply discounted in order to place it all in the wood preservative market. Thus, optimum marketing strategy would be not to convert the entire Great Plains tar oil stream to creosote, but to combine creosote production with coproduction of rubber processing oils, coal tar asphalt, etc.

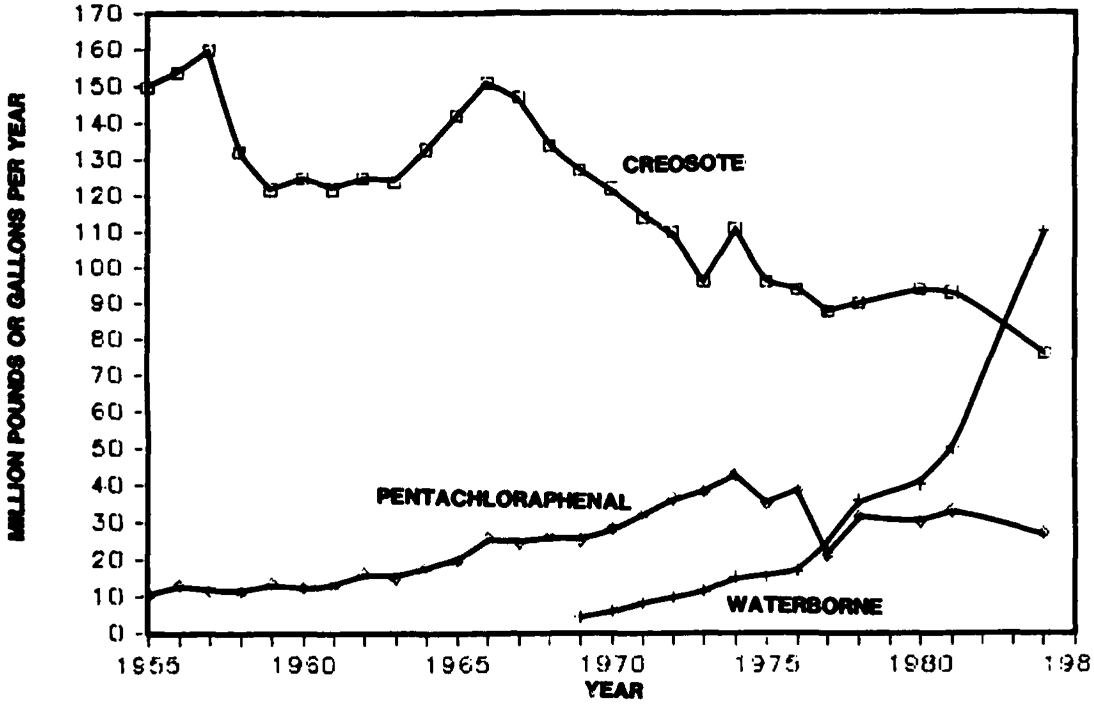


FIGURE 18

WOOD PRESERVATIVE CONSUMPTION
CREOSOTE-MM GAL., ALL OTHERS-MM LBS.

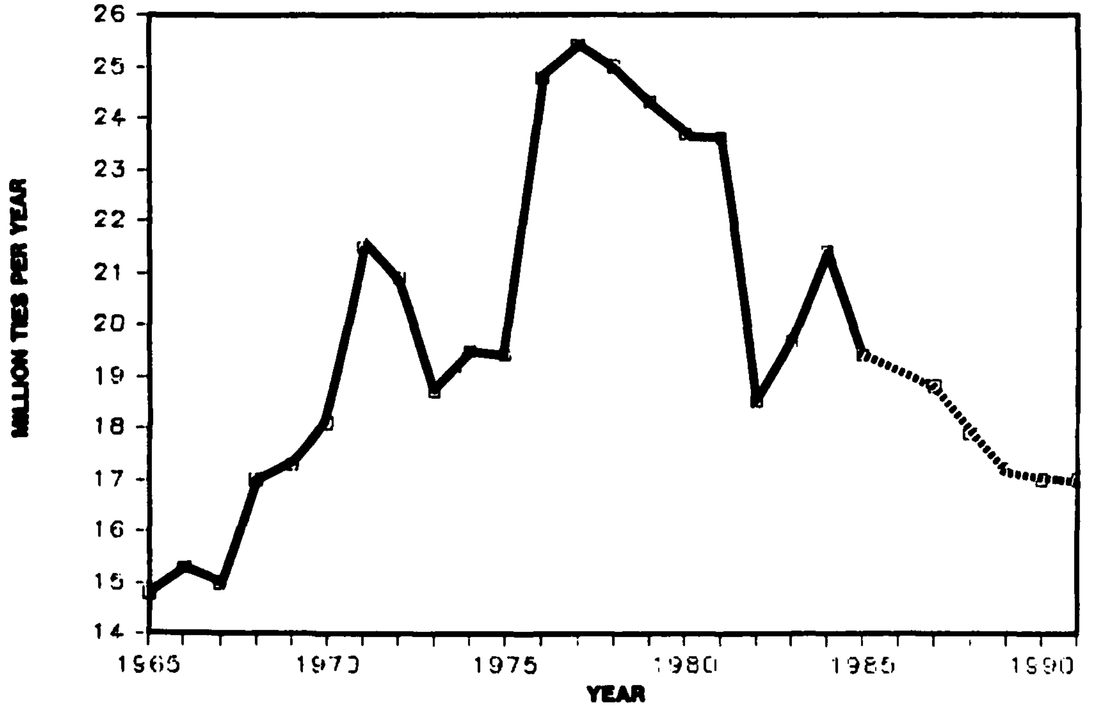


FIGURE 19

TREATED CROSSTIE INSERTIONS
BY UNITED STATES CLASS 1 RAILROADS

Although AWPA specifications state that creosote must be derived from coal tar, creosote prices are not entirely insulated from petroleum prices. This is because, first, some uses allow the substitution of up to 50 percent petroleum oil, and second, alternative uses for the creosote fraction compete directly with petroleum. Thus decreases in petroleum prices force down creosote prices for alternative uses, creating pressure on the prices for wood preservative. Because the contracting cycle for large-volume creosote users is 12 months long, the effects of the early 1986 crash in oil prices is only now being translated fully into the creosote market.

Figure 20 shows clearly that creosote price changes lag, but eventually follow oil price changes. Because creosote can substitute for petroleum as a fuel, upward trending oil prices quickly stimulate upward trending creosote prices. Because petroleum cannot substitute for creosote, however, downward trending oil prices will affect creosote more slowly. The down trend in petroleum prices in the last few years has been temporarily counter-balanced by decreases in creosote capacity. The historical relationship in Figure 20 suggests that since 1987 oil prices correspond to about 1979 oil prices, 1987 creosote prices should correspond to about 1979 prices. This would be about $0.80 per gallon. Contact with creosote buyers indicates that this is indeed the market level, although not yet reflected in the Chemical Marketing Reporter data.

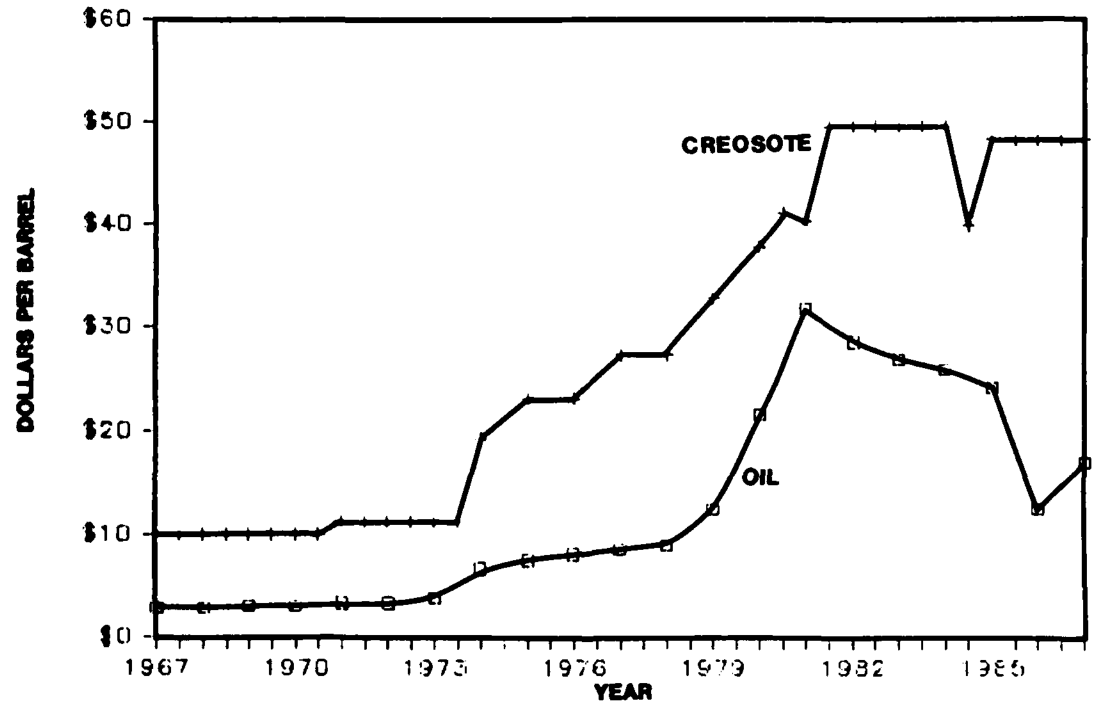


FIGURE 20

CREOSOTE AND OIL PRICES

CRESOLS AND CRESYLIC ACID

Definitions and Specifications

The Phenosolvan crude phenol contains mostly monohydric "phenols", which include phenol, cresols, xylenols, ethylphenols, and other alkylphenols as well as some polyhydric "phenols", including catechols and resorcinol.

The term "cresols" is used to designate the isolated monomethyl phenols, either as pure ortho, meta, or para isomers or as mixtures of isomers. This report uses the term "phenol" to denote the chemical monohydroxybenzene and the term "crude phenol" to denote the complex mixture of mono- and polyhydric aromatics.

Crude phenol can be separated into fractions which can be designated as tar bases, neutral oil-free phenol, cresylic acids, and phenolic pitch.

"Cresylic acid" refers to various mixtures of tar acids, mostly polyhydric phenols and monohydric phenols higher than C_6. Cresols may be the chief constituents in some mixtures, in others the xylenols (dimethyl phenols) and higher boiling homologs of phenol may predominate. The individual compounds all have boiling points in the range 180-230°C.

Phenolic resins manufactured with cresols and other constituents of crude phenols require feedstocks typified by the following:

- Meta-cresol 50-70 percent
- Not more than 0.25 percent neutral oil
- Not more than 0.17 percent pyridine base
- Distillation range as required by consumer

Companies that report production data to the United States International Trade Commission define cresols as phenolic mixtures in which 50 percent of the material boils below 204°C and cresylic acids as phenolic mixtures in which 50 percent of the material boils above 204°C. The category "cresylic acid, refined" includes primarily cresol/xylenol mixtures, many of which contain a high percentage of xylenol. It may also include some xylenol mixtures sold either as is, or used for further separation of the individual xylenol isomers. Some higher boiling phenolic tar acids may also be included in the refined cresylic acid category. Refined cresylic acid is defined the same as crude cresylic acid except that the yield of product distilling below 215°C is more than 75 percent by weight of the original distillate.

Specific end-uses will require limitations on various minor components present in the Great Plains liquids. For instance, guaiacol causes problems for certain products. Other uses require low pyridine limits. In other cases the phenol content must be zero.

Production

Total cresols production in the United States is shown in Figure 21. The last year of data available, 1985, shows a dramatic drop in production. Several producers of synthetic cresols closed down about that time. Current producers of natural cresylics state that their sales were not widely variable from 1984

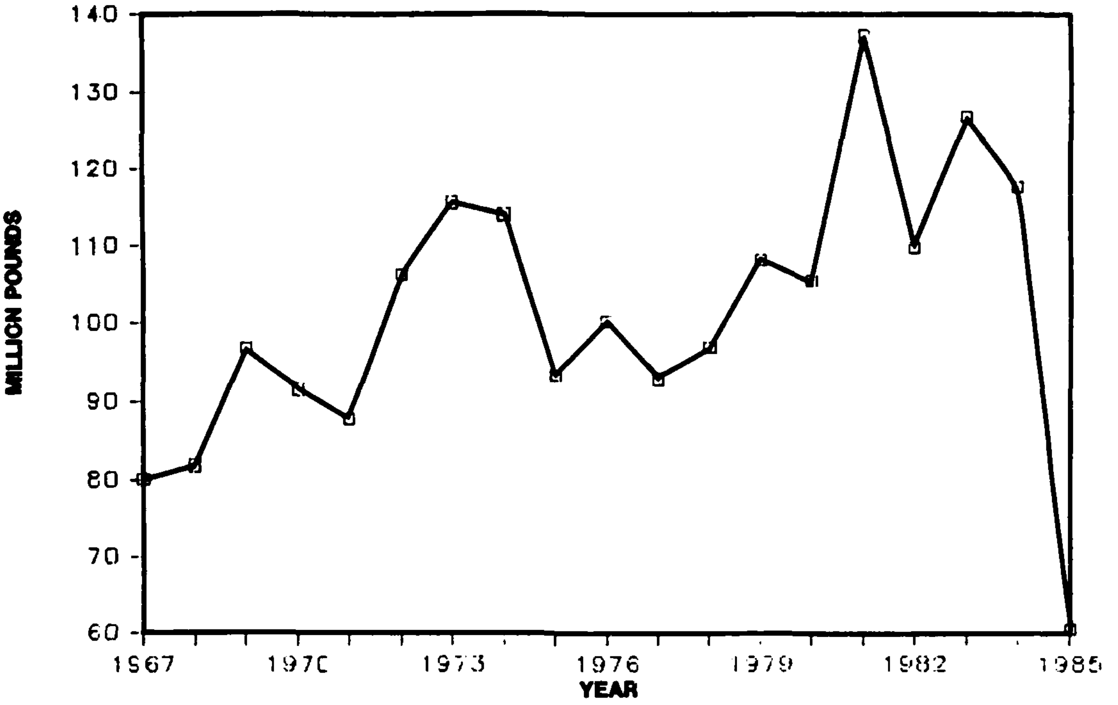


FIGURE 21

CRESOLS PRODUCTION, TOTAL

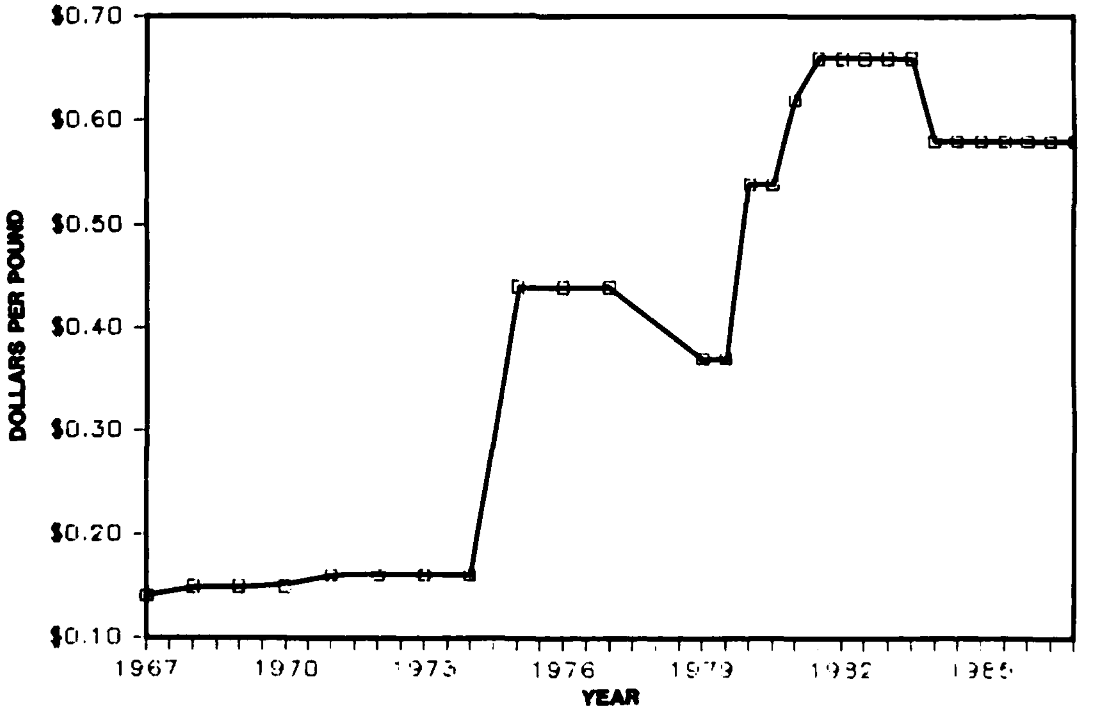


FIGURE 22

CRESYLIC ACID PRICES
TANKS, FREIGHT ALLOWED

to the present, so the drop in Figure 21 appears to be related only to synthetic cresols.

Prices

Prices for cresylic acid are shown in Figure 22. Prices for the individual cresol isomers are shown in Figures 23 through 26. Prices have been on a stable or rising trend in all cases except for p-cresol. The reason for aberrant p-cresol prices is not known. One of the major known uses for p-cresol is to make the anti-oxidant BHT.

The prices shown in Figures 22 through 26 must be interpreted with caution. Although useful for showing long-term trends, prices from the Chemical Marketing Reporter are known to be unreliable for cresols. The long, flat trend in Figure 24, for example, is simply due to the fact that no new price postings have been received since 1981, and is not the result of a truly stable market.

Actual 1987 market prices for mixed cresylic acids are approximately $0.40 per pound.

Consumers

Cresylic acid mixtures containing a high fraction of m-cresol can be used for synthesis of phenol-formaldehyde resins and high-quality engineering plastics, such as polycarbonates.

Because of the difficulty of controlling the product resin properties with a mixed cresylic feedstock, the market for such material is small relative to the phenol market. The compound cresol, which is the most useful component of cresylic acid, has ortho, meta, and para isomers which have different commercial values. Meta-cresol is the preferred isomer for preparing phenol-formaldehyde molding compounds and adhesives from cresylic acid feedstock. The o-cresol and p-cresol react more slowly to yield lower quality resins than does m-cresol. Consequently, cresylic acid with the highest m-cresol content is the most marketable. (Compare Figures 23, 24 and 25). Cresylic acid competes with phenol as a feedstock for phenol-formaldehyde resins. Because synthetic phenol is pure, the control of resin product properties is easier. The decline in coal tar production and the difficulty of product quality control with cresylic acids have discouraged their use in the petrochemical industry.

Cresols were at one time used extensively to make the phosphate esters tricresyl phosphate and cresyl diphenyl phosphate, but these have been replaced by phenolic phosphates. Several different cresols and cresylic acid mixtures are used as wire enamel solvents, ore flotation frothers, disinfectants, fiber treatments, tanning agents and degreasing agents. High-purity m-cresol is used to make thymol (cough medicines) and pyrethroid insecticides.

In the electrolytic zinc process, cresylic acid may be used as a frother to trap gases emitted from the anodes and cathodes. Cresols were once important as paint removers, but have been eliminated because of toxicity. Cresylic acid is used as an aromatic solvent in the Duo-Sol process for refining

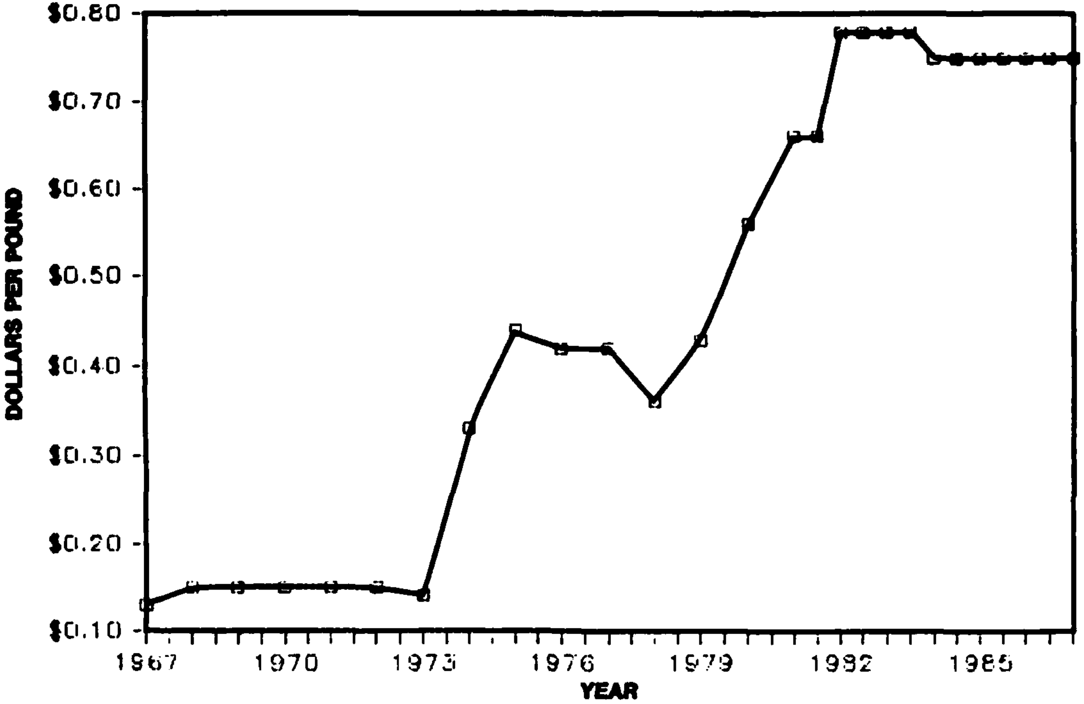


FIGURE 23

o-CRESOL PRICES
98% PURE, DMS, TL, TANKS, FOB

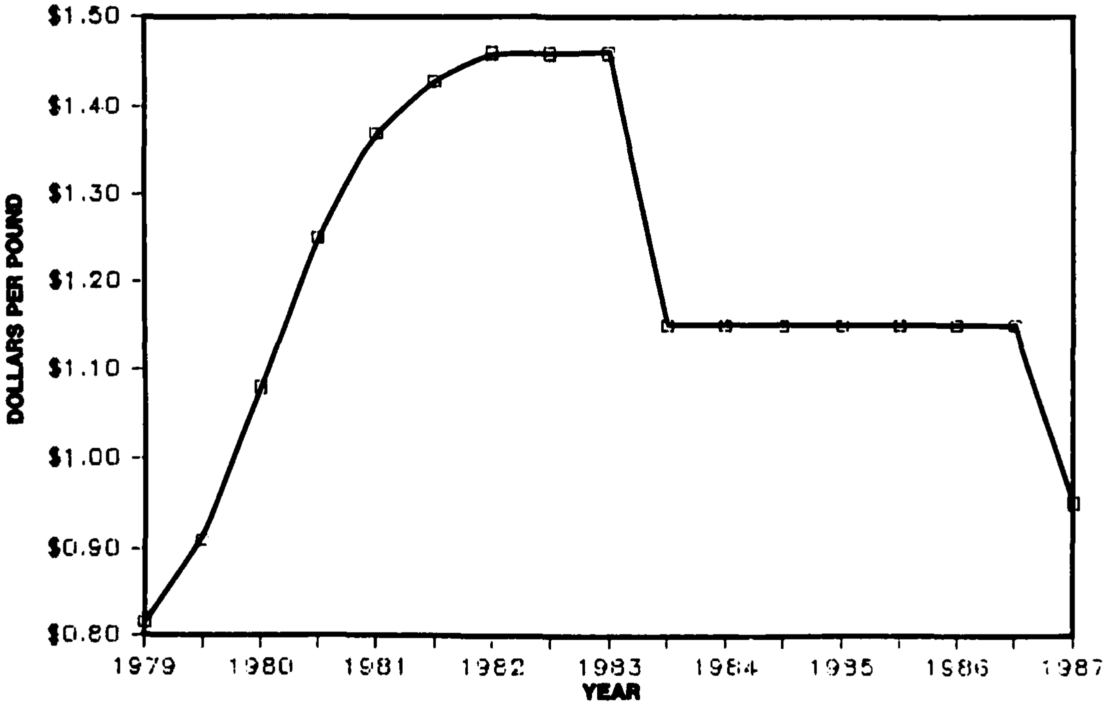


FIGURE 24

p-CRESOL PRICES
DMS, TL, TANKS, FOB

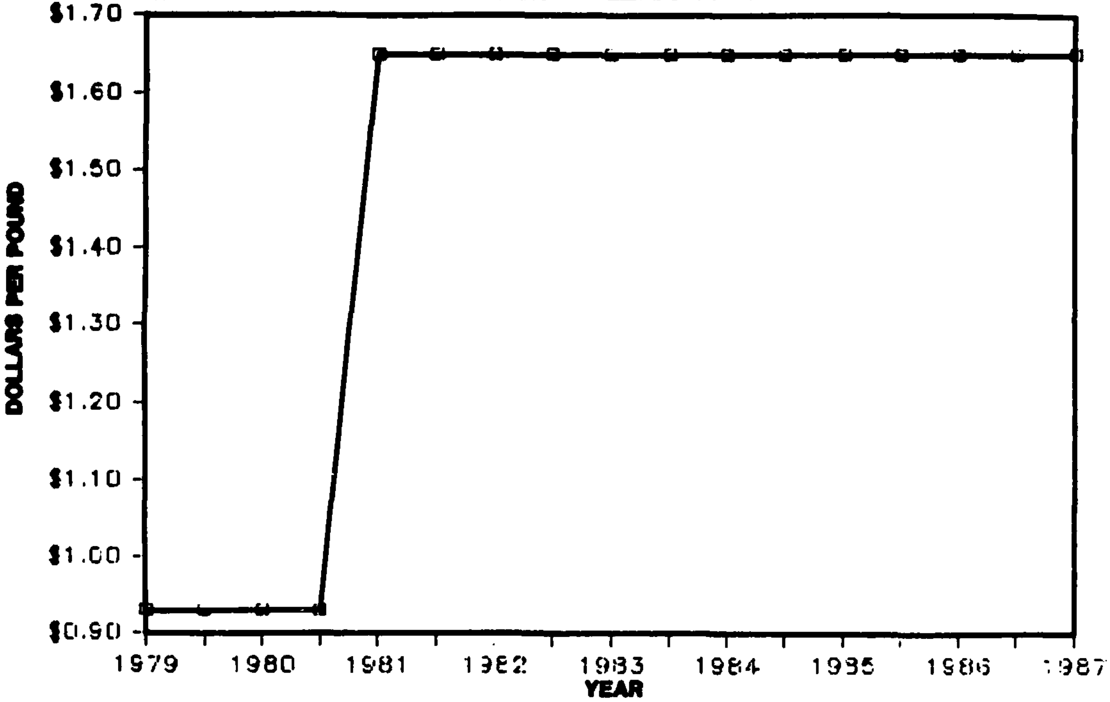


FIGURE 25

m-CRESOL PRICES
TANKS, DMS, TL, FOB

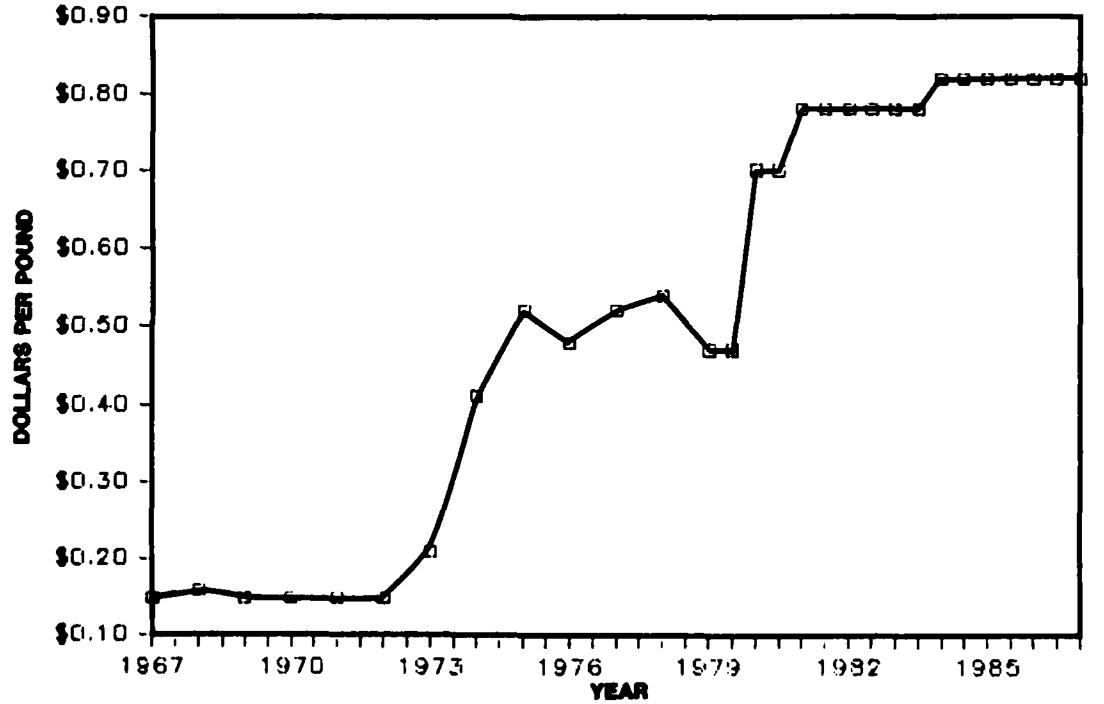


FIGURE 26

m,p-CRESOL PRICES
BULK, FOB

lubricants. Ortho-cresol is used in insecticides. An end-use breakdown for consumption of total cresols and cresylic acid in 1981 is given as follows:

Magnet wire	17
Antioxidants	15
Resins	13
Exports	11
Phosphate esters	8
Cleaning compounds	6
Ore flotation	6
Miscellaneous	25
	100%

In 1986, a large demand for low-grade cresylics opened up in China. However, the prices offered are very low, in the range $0.15 to $0.18 per pound.

Producers

Natural cresols and cresylic acid can be produced as by-products of both petroleum and coal tar refining. Petroleum-based cresols are the result of catalytic cracking processes and are obtained from the caustic liquor used to wash the petroleum distillates. Although cresylic acids were formerly obtained from several coal tar sources in the United States, there is currently no production from this source. The only producers of natural cresylic acids are PMC (formerly Productol) in Santa Fe Springs, California, Northwest Petrochemical in Anacortes, Washington, and Merichem in Houston, Texas. Although Merichem uses some imported coal-tar-derived feedstock, none of the three currently use feedstock from domestic coal-based materials. All three state that they would use such materials if available, and all expressed an interest in the Great Plains material.

A major factor on the world market scene is cresylic acid from the SASOL coal conversion plants in South Africa. SASOL has been selling crude cresylics to others for refining, but it is believed that international trade sanctions against South Africa have reduced their ability to sell on the world market. It is thought that SASOL intends to install a hydrocracker to convert the cresylics to fuel products.

Synthetic cresols are produced from petroleum. One route is the catalyzed methylation of phenol. High-purity p-cresol can be made by toluene sulfonation. A m,p-cresol mixture can be manufactured via cymene, obtained by the alkylation of toluene. Although there were five United States producers of synthetic cresol isomers until recently, the only two companies involved in 1987 are General Electric (o-cresol) in Selkirk, New York, and PMC (formerly Sherwin-Williams) in Chicago (p-cresol).

Market Structure

Great Plains would have the option of either selling its crude cresylics to a cresylic acid refiner, or refining in a toll processing facility, or installing its own refining facilities and marketing to the manufacturers of resins, etc. In the former case, there are only three possibilities, at least in the United States. Of the three, only Merichem has a large enough capacity to process the entire Great Plains crude streams.

Overseas markets probably offer the best opportunity at present because major European users are attempting, for political reasons, to find sources other than South Africa's Sasol.

Present market prices for refined cresylic acid are about $0.40 per pound. It is estimated that refining costs are on the order of $0.25 and that sales costs are on the order of $0.08 to $0.10 per pound. This leaves a net price for crude cresylics of $0.05 to $0.07 per pound, or about $17 per barrel. This corresponds to one refiner's estimate that the current price for crude cresylics would be roughly equivalent to fuel oil value. This study did not consider the option of toll processing through other facilities which may be available. It is possible that lower costs might be obtainable through such facilities.

The very small number of producers of both synthetic and natural cresols makes for a closed market situation. It may be very difficult for a new producer to obtain a major share of a business which is held by only two or three producers. The total potential cresylic acid production from Great Plains is 80 million pounds per year, which is of the same order of magnitude as current total domestic demand. In other words, it would be necessary to drive all other natural cresylic acid out of the market entirely if the Great Plains output were all consumed domestically.

Market Outlook

The outlook for natural cresylic acids acknowledges two broad, long-term negative factors. One is the general loss of market share by natural products to higher-purity synthetic materials. The other is the toxic and carcinogenic nature of coal tar products, which prompts users to find more benign substitutes. Currently, low petroleum prices act to accentuate the conversion to petroleum-derived substitutes.

None of the uses listed for natural cresylics has been identified as a high-growth area. Although individual cresol isomers may see increasing demand, these can be derived in high purity from petroleum components. Cresylics are often low-performance feedstocks for resins and other uses. In ore flotation, for instance, cresylic acid frothers are usually much less efficient than glycols. Also, flotation reagents must contain essentially zero phenol because of water pollution problems. Because petroleum-derived synthetics can substitute for all natural cresylic applications, future demand and price levels will both be constrained by petroleum prices. The outlook therefore is for no price increases relative to petroleum, and for static or decreasing demand levels.

A compensating factor in the short term is the price of phenol derived from benzene. Benzene prices are rising substantially due to demand for polystyrene and for octane enhancement in the gasoline pool. Because cresols compete with phenol in some applications, this will offer an opportunity for cresol price increases until benzene prices return to equilibrium values.

CARBON BLACK FEEDSTOCK

Definitions and Specifications

Carbon black can be made by the partial combustion of any carbonaceous liquid or gaseous fuel with insufficient air. There are basically three modern methods of making carbon black, known as the channel process, the furnace process, and the thermal process. Almost all current United States production is achieved via the furnace process using oil feedstocks. The process is operated in an insulated furnace chamber. An auxiliary fuel is first burned to completion to supply the necessary process heat, raising the temperature of the gas stream to about 2,500 °F. Oil is then mixed with the hot gas and pyrolyzed instantly. The carbon black laden gas stream is cooled,and the carbon black removed by cyclones, electrostatic precipitators or bag houses.

In the United States, carbon blacks are produced almost exclusively from petroleum derived feedstock, although coal-derived liquids have been used, and are more widely used elsewhere in the world. Oil feedstocks must be highly aromatic and have low ash and asphaltene contents. The United States Bureau of Mines Correlation Index (BMCI) is used as an index of feedstock aromaticity by most carbon black manufacturers. The BMCI is given by the formula:

$$\text{BMCI} = 100\ (876/A + 670/B - 4.568)$$

where:

A = 50% boiling point plus 460 °F
B = 131.5 plus degrees API

Typical specifications for a carbon black feedstock would be a minimum BMCI of 130. Low BMCI oils give much lower yields of carbon black. Other specifications are listed in Table 39. Because the yield of carbon black is relatively low (2.5 to 5 pounds per gallon) in all cases, low feedstock prices are highly desired.

True carbon black is formed by vapor phase cracking and/or condensation of hydrocarbons. Both the formation of the solid carbon nuclei, and their subsequent growth into high-surface-area particles must occur directly from the vapor phase. If, instead, cracking occurs in the liquid phase, the result will be the formation of coke or grit particles in the carbon black. These will have the same deleterious effect as ash. Thus a primary requirement for a carbon black feedstock is that it be completely vaporizable in a very short time. Because asphaltenes cannot be vaporized in this way, they are undesirable.

The most important requirement for carbon black feedstock is that it be highly aromatic. Large compact molecules with many double bonds and short side chains have a greater tendency to polymerize and eventually form carbon than long straight chain molecules which tend to crack into smaller fragments. Compounds having two or more fused aromatic rings have very high BMCI values and provide the best feedstock.

The aromaticity of the feedstock influences the properties as well as the yield of the carbon black product. While a wide range of black particle sizes

TABLE 39

TYPICAL CARBON BLACK OIL SPECIFICATIONS

BMCI	130 Minimum
API Gravity	2 Maximum
Viscosity, SSV @ 210 °F	125 Maximum
Sulfur	2.2% Maximum
Asphaltenes	5% Maximum
Ash	0.05% Maximum
BS&W	0.2% Maximum
Sodium	10 ppm Maximum
Potassium	1 ppm Maximum
Flash Point	160 °F Minimum
Aniline Number	100 Maximum
Initial Boiling Point	500 °F
50% Distillation Point	900 °F

can be obtained from almost any oil feedstock by adjusting the furnace conditions, the structure of the carbon black is determined largely by the aromaticity of the feedstock. "Structure" is the linking together of carbon black particles into chains. High structure indicates long chains, which are required for good reinforcement and abrasion resistance in synthetic rubber. The concentration of aromatics in the fuel determines the rate at which carbon black nuclei are formed. High rates result in small particle size and high structure.

Currently, the most suitable carbon black feedstocks are the high boiling bottoms from fluid catalytic cracking processes. Carbon contents of over 90 percent are typical.

Production

Current carbon black production figures are not available, but United States production was essentially static at approximately three billion pounds per year from 1970 to 1980. It is not believed to have changed significantly since then. At a yield of 3.75 pounds per gallon, this would indicate a carbon black oil demand on the order of 50,000 barrels per day. This number was confirmed in informal communications with the industry.

At most, 50 percent of the Great Plains tar oil output, (the portion boiling above 500 °F) or 2,500 barrels per day could conceivably qualify as carbon black feedstock. This would represent five percent of the total United States demand.

Prices

Prices for carbon black feedstock are given in Figure 27. Prices are usually based on Gulf Coast plus transportation. The base price is the price for 3 percent sulfur #6 residual fuel oil. Every 10 points increase in the BMCI value is worth $0.50 per barrel, and every percentage decrease in sulfur content below three percent is worth one percent increase in price. However, the maximum premium allowed over 3 percent sulfur residual fuel prices is almost never more than one dollar per barrel.

Residual fuels of the type used for carbon black feedstock are often difficult to sell in the Great Plains marketing region because of a low demand for residual fuels in general and the lack of alternate uses for the material. Thus FCC recycle oil, a good carbon black feedstock, has recently been selling for only $8 per barrel at the Amoco refinery in Mandan, North Dakota, and only $6 per barrel at the Frontier refinery in Cheyenne, Wyoming.

Consumers

Major carbon black plants are listed in Table 40 and Figure 27A. A considerable consolidation of the industry occurred in the early 1980's, with almost a billion pounds of production capacity closed down.

Producers

The major source of carbon black oil is fluid catalytic cracker bottoms from oil refineries. Thus all major oil refineries are potential competitors for this market.

TABLE 40

MAJOR UNITED STATES CARBON BLACK PRODUCERS

Company	Location	Carbon Black Capacity, MMlb/yr
Ashland	Aransas Pass, TX	160
Ashland	Belpre, OH	120
Ashland	New Iberia, LA	260
Cabot	Franklin, LA	230
Cabot	Pampa, TX	60
Cabot	Villa Platte, LA	305
Cabot	Waverly, WV	180
Columbian	El Dorado, AR	90
Columbian	Mojave, CA	55
Columbian	Marshall, WV	155
Columbian	North Bend, LA	180
Columbian	Hickock, KS	60
Continental Carbon	Phenix City, AL	55
Continental Carbon	Ponca City, OK	132
Continental Carbon	Sunray, TX	98
J. M. Huber	Borger, TX	120
J. M. Huber	Baytown, TX	175
J. M. Huber	Orange, TX	135
Sid Richardson	Borger, TX	275
Sid Richardson	Addis, LA	123
Sid Richardson	Big Spring, TX	108
Total		3,076

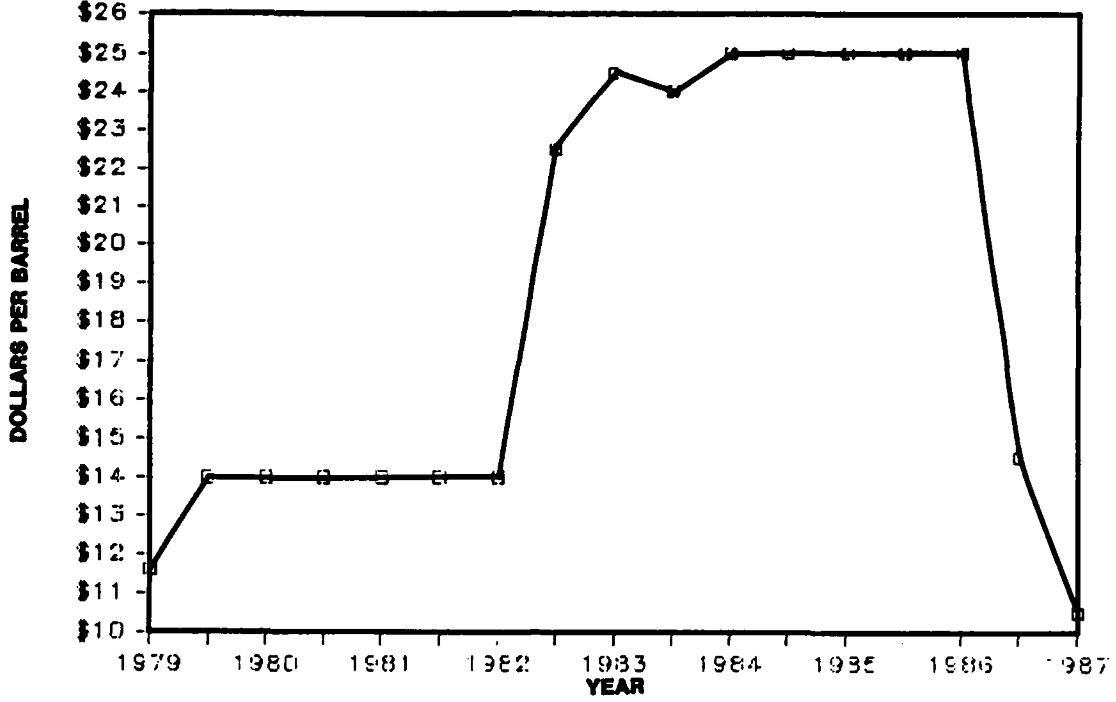


FIGURE 27

CARBON BLACK OIL PRICES
BASED ON GULF REFINERIES

FIGURE 27A

LOCATIONS OF CARBON BLACK PRODUCERS

Market Structure

Most carbon black feedstock is purchased on the spot market and therefore follows spot oil prices very closely. Some is purchased under contract. In either case, a new material, regardless of meeting specifications, would probably have to be subjected to a test burn before purchase. This might involve a truck load of material.

Market Outlook

Demand for carbon black oil has declined as a result of improvements in the conversion efficiency of the furnace process and as a result of declining demand for tire production.

There are many different commercial grades and varieties of carbon black. By far the greatest use, however, is as a reinforcing agent in rubber tires (90 percent). The finely divided state of carbon black greatly reduces oxidation of the rubber and increases the tensile strength. It is a little-known fact that carbon black may account for over half of the weight of a tire.

Recent trends to smaller cars and smaller tires, longer wearing radials and emergency-only spares have all acted to retard the demand for automotive rubber and thus for carbon black. These trends appear to have bottomed, and carbon black may be ready to resume a modest growth period. Carbon black feedstock prices, however, will remain strictly related to petroleum prices.

BENZENE, BTX

Definitions and Specifications

Almost all of the benzene and BTX (benzene, toluene, xylene) aromatics in the United States are now derived from petroleum. Small amounts are derived from coke oven light oil. Chemical grade benzene must meet a minimum freezing point specification of 5.35 °C, corresponding to a product purity of 99.7 percent. Other typical specifications are listed in Table 41. BTX mixtures are not sold to general specifications.

Production

Benzene production data are given in Figure 28. These data represent only the amount of benzene isolated as such, not the total amount produced by catalytic reformers and left in the gasoline stream at refineries.

There are four major sources of BTX or benzene liquids:

1. Catalytic reforming of petroleum naphtha
2. Pyrolysis gasoline from ethylene plants
3. Hydrodealkylation of toluene
4. Recovery from coke oven light oil

Benzene recovery from coke ovens declined drastically from 1979 to 1982 (Figure 29).

The volume of BTX isolated and used for chemicals production is relatively small compared to usage in gasoline. Because of high octane values, BTX liquids are valuable gasoline components. It is estimated that 50 percent of total benzene and 90 percent of total toluene and xylenes end up in the gasoline pool.

Most of the catalytic reformate and some pyrolysis gasoline is used directly in gasoline without extracting the aromatics for chemical use. If only one aromatic product is desired and low purity is acceptable, it can be removed from the stream by extractive distillation with a solvent such as phenol. If more than one product is desired, and high purity is important, then liquid-liquid extraction is used. The most widely used extraction process is the Sulfolane process.

Prices

Because of the large usage in the gasoline market, the amount of BTX available for chemicals manufacture fluctuates from time to time, with a corresponding effect on merchant prices. A benzene price history is given in Figure 30.

The drastic reduction in the amount of lead allowed in gasoline, starting in 1986, is having a predictable effect on benzene prices. As refiners are forced to keep more BTX in the gasoline stream in order to meet octane requirements without tetraethyl lead, and as demand has increased for petrochemicals such as styrene, benzene availability is dropping and prices have climbed sharply in early 1987, to levels of around $1.50 per gallon.

TABLE 41

SPECIFICATIONS FOR COMMERCIAL GRADES OF BENZENE

Specification	Refined Benzene-535 (ASTM D2359-69)	Refined Benzene-485 Nitration-Grade (ASTM D835-71)	Industrial-Grade Benzene (ASTM D836-71)
Specific Gravity	0.8820-0.8860	0.8820-0.8860	0.875-0.886
Color (ASTM D1209)	No darker than 20 max on the platinum cobalt scale		
Distillation Range	Not more than 1 °C including 80.1 °C	Not more than 1 °C including 80.1 °C	Not more than 2 °C including 80.1
Solidifying Point	5.35 °C min	4.85 °C min	
Acid Wash Color (ASTM D848)	No. 1 max	No. 2 max	No. 3 max
Acidity (ASTM D847)	Nil	No free acid	
Sulfur Compounds	Free of H_2S and SO_2	Free of H_2O and SO_2	Free of H_2S, SO_2
Thiophene	1 ppm max		
Copper Corrosion (ASTM D849)	Copper strip shall not show discoloration		
Nonaromatics (ASTM D2360)	0.15% max		

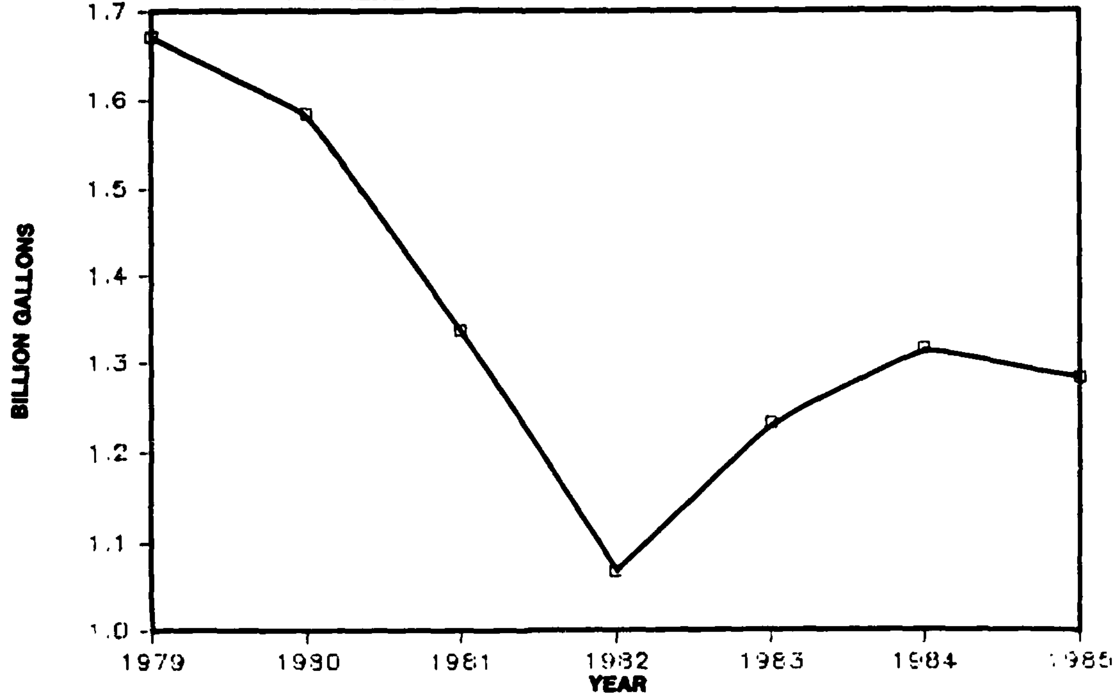


FIGURE 28

BENZENE PRODUCTION, ALL GRADES

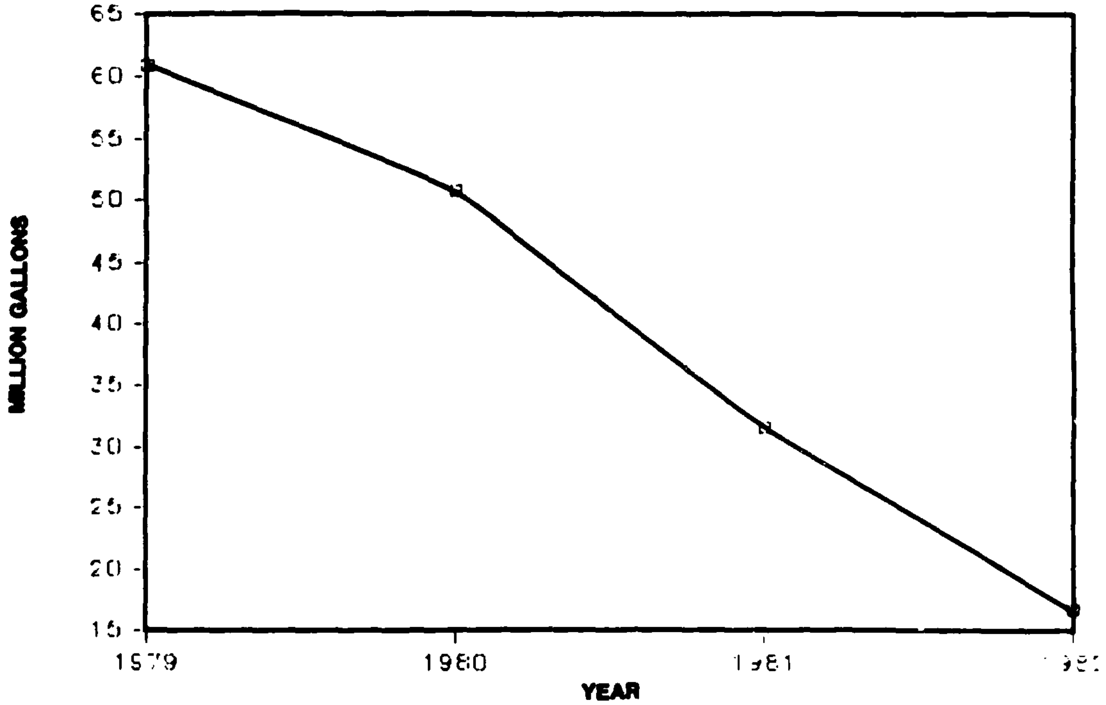
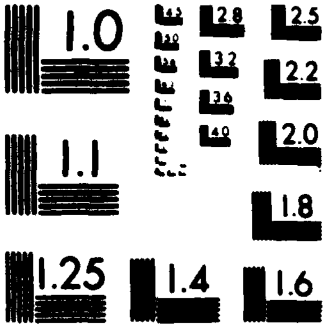


FIGURE 29

BENZENE PRODUCTION
BY COKE OVEN OPERATORS

AD-A184 846 PRODUCTION OF JET FUELS FROM COAL DERIVED LIQUIDS 2/3
VOLUME 1 MARKET ASSESSM..(U) NORTH DAKOTA UNIV GRAND
FORKS ENERGY RESEARCH CENTER J E SINOR AUG 87
UNCLASSIFIED AFWAL-TR-87-2042-VOL-1 MIPR-FY1455-86-N0657 F/G 21/4 NL



MICROCOPY RESOLUTION TEST CHART

NATIONAL BUREAU OF STANDARDS 1963 A

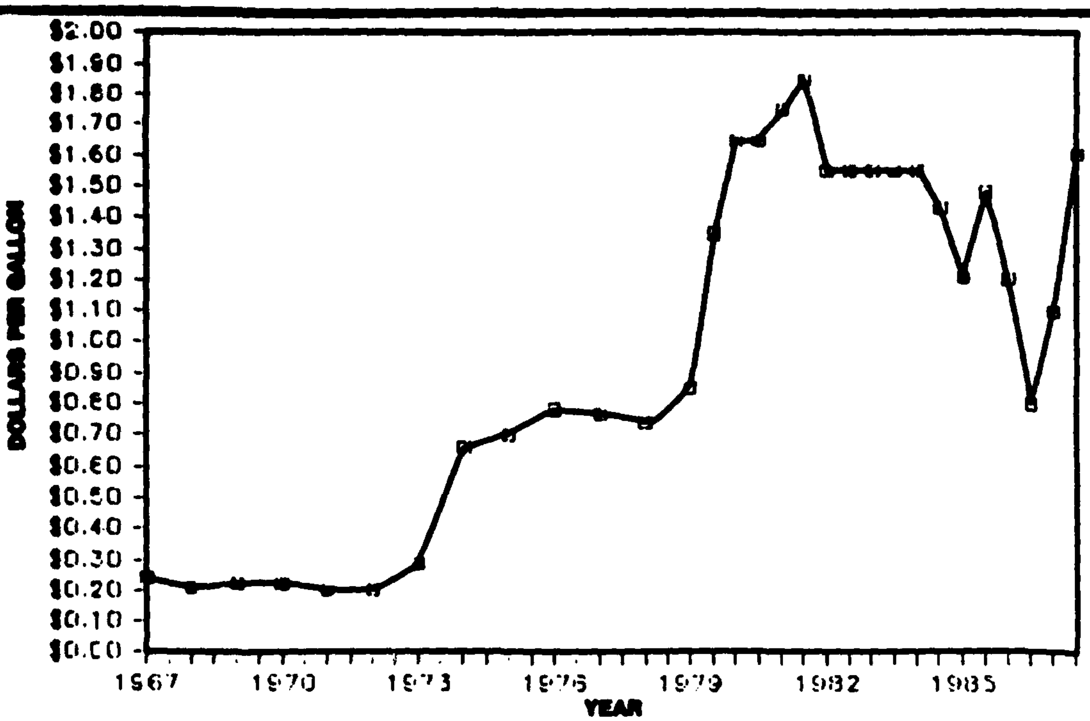


FIGURE 30

BENZENE PRICES
BASED ON BARGE,FOB

Consumers

The largest volume uses for BTX aromatics (other than gasoline) are for the manufacture of plastics and fibers. Major end products of benzene include styrene monomer for polystyrene production, cumene for phenol production and cyclohexane for nylon production. Major end products of toluene include solvents, and toluene di-isocyanate for production of polyurethane foams. Xylenes are used in paints, solvents, plastics and polyester fibers. Most o-xylene is first converted to phthalic acid and most m-xylene is first converted to isophthalic acid. Any excess materials simply find their way back to the gasoline market.

One option for Great Plains would be to sell the naphtha stream to a company having excess hydrodealkylation capacity. A number of such facilities exist, and some are being re-commissioned in light of the 1987 benzene market. Those being mentioned for re-commissioning include Standard Oil in Lima, Ohio, Dow Chemical in Freeport, Texas, Sun Oil in Toledo, Ohio, Coastal Corporation in Corpus Christi, Texas, and Crown Central in Houston, Texas. These units, however, probably could not accept the mixed Great Plains naphtha unless blended in small quantities. Toluene hydrodealkylation units are based on either catalytic (UOP's Hydeal and Houdry's Detol processes) or thermal processes (HRI's HDA and Gulf's THD processes) which would not accept an impure stream like the Great Plains naphtha unless blended off to small concentrations. Suitable processes for such a stream are Houdry's Pyrotol or Litol processes. Ethylene plant by-products are generally processed with Pyrotol and coal tar products with Litol. Litol units are installed at Polysar/Petrosar in Sarnia, Ontario and at Bethlehem Steel in Baltimore.

The other option would be to build a hydrodealkylation unit at the Beulah facility and sell benzene in the merchant market. Possible consumers would include any of the many manufacturers of the aromatic chemicals listed earlier.

Producers

The primary source of BTX liquids is catalytic reforming in petroleum refineries. The objective of reforming is to convert paraffinic and naphthenic compounds to aromatics. The feed is usually desulfurized before being charged to the reforming unit. The usual feed is either a straight run or a cracked naphtha fraction boiling over the range 66 to 204 °C if gasoline is the desired product, or 66 to 132 °C if BTX chemicals are the desired product. The most common process for reforming is the Platforming process, licensed by UOP. All major petroleum refineries have catalytic reforming units. Total United States capacity is on the order of 250,000 barrels per day of BTX liquids, about one-fourth of which would be benzene.

A second significant source results from the steam cracking of hydrocarbons to make ethylene and propylene. An aromatics-rich by-product stream called pyrolysis gasoline, dripolene, or drip oil, is produced. This material is a mixture of hydrocarbons, olefins, diolefins, styrenes and aromatics. When heavy feedstocks are used, the pyrolysis gasoline may contain high concentrations of BTX. After hydrogenation to saturate the olefins, the BTX's may be recovered by extraction.

Potential benzene recovery from pyrolysis gasoline is estimated to be on the order of 30,000 barrels per day, all from ethylene plants located on the Gulf Coast.

If additional benzene is needed above that present in BTX streams, it is obtained by the dealkylation of toluene. Processes which accomplish this include hydrodealkylation and disproportionation (in which two molecules of toluene are converted to one of benzene and one of xylene).

Hydrodealkylation processes provide the swing capacity needed to match benzene supplies to fluctuating demand. These units are started up or shut down depending on benzene demand and the benzene to toluene price ratio. Thus capacity is usually far in excess of actual production at any given point in time. Because of the difficulty of determining the condition of shut down plants, it is difficult to derive an effective production capacity for hydrodealkylation, but it is believed to be on the order of 50,000 barrels per day, heavily concentrated in the Gulf Coast area.

Although the production of BTX liquids from coke oven by-products was once an important factor it is no longer significant (Figure 29). In 1981 there were six producers of BTX from coke oven light oil but the 1985 survey by the United States International Trade Commission identified only two remaining, Bethlehem Steel and USS Chemicals. Only USS Chemicals (now Aristech) is believed to be in the business at this time. Competition from this source should have no effect on the marketability of benzene from Great Plains.

Market Structure

Most hydrodealkylation plants are based on captive toluene sources. Although some of the benzene product is captively consumed, most of it is sold to others. Thus the benzene market may be characterized as open. Both spot sales and contract sales may be used. Hydrodealkylation plants are sometimes operated on a toll basis (processing feed for others, for a fee).

The maximum Great Plains output of 32 million pounds per year from the Rectisol naphtha stream and 24 million pounds per year from the tar oil stream would amount to less than one percent of United States benzene production (Figure 28) and should have no effect on market prices.

Market Outlook

The need for octane enhancement to replace lead in gasoline should have a positive effect on the benzene market for several years. The recent sharp rise in benzene prices, however, is most likely not sustainable. For the long term, benzene prices will be set at the margin by the costs of toluene hydrodealkylation. If benzene prices stay high, more dealkylation units will come onstream until the price drops far enough that some of them will once again shut down. Based on historical relationships, that price is estimated to be $1.15 per gallon at early 1987 oil prices.

PHENOL

Definitions and Specifications

Phenol and other constituents of crude phenols are basic building-block materials for the United States petrochemical industry. A wide variety of plastics, chemicals, and drugs are derived from phenol and closely related compounds. Some ambiguity surrounds the definition of "phenol" and "phenols" as the terms are applied in the coal tar and petrochemical industries. The chemical "phenol" is monohydroxybenzene, i.e., a benzene ring with one hydroxyl (-OH) group attached. It is sometimes known as carbolic acid. The term "phenols" is also used industrially to describe a large family of compounds with one or more hydroxyl groups attached to aromatic rings. The crude phenol available from coke ovens and coal gasification plants contains tar acids, tar bases (pyridines, picolines), neutral oil, organic acids, and pitch, recovered by extraction of gas liquor using the Lurgi Phenosolvan process. The crude phenol contains monohydric "phenols," which include phenol, cresols, xylenols, and ethylphenols. The crude phenol may also contain polyhydric "phenols," including catechols and resorcinol.

The term "cresols" is used to designate the isolated monomethyl phenols, either as pure ortho, meta, or para isomers or as mixtures of isomers. This report uses the term "phenol" to denote specifically the chemical monohydroxybenzene and the term "crude phenol" or "total phenols" to denote the complex mixture of aromatics coming from the Phenosolvan process.

Phenol may be synthesized from benzene, toluene, or cumene. Over 90 percent of synthetic phenol is synthesized from cumene, for which phenol synthesis is the only use. Originally, coal was the predominant source of phenol and other precursor chemicals for resins and plastics. As long ago as 1966, however, 96 percent of the phenol produced in the United States was "synthetic."

The USP specifications for phenol are as follows:

- Phenol content of 98 percent or more
- Clear solubility of one part phenol in 15 parts water
- Fusion temperature 40.9 degrees C
- Boiling point 181.0 degrees C
- Specific gravity at 45/20 C of 1.0563
- Content of nonvolatiles not more than 0.05 percent

To control the properties and purities of subsequent synthesis products, most synthetic phenol is used and sold at a purity of over 99.5 percent. Typical specifications are given in Table 42. Pharmaceutical-quality phenol must pass the most stringent quality specifications of all uses. Commercial grades of natural phenol containing 90-92 percent or 80-82 percent phenol have been marketed in small quantities.

Production

In the bulk of its ultimate markets, phenol suffers from cyclical demand, as illustrated in Table 43 and Figure 31.

TABLE 42

PHENOL SPECIFICATIONS

Property	Specification	Test Method
Appearance	Crystalline solid	Visual
Color Of Melt, APHA	10 max.	ASTM D-1686
Color Of Sodium Hydroxide Solution	1.5 max.	ASTM D-1500
Freeze Point, °C	40.6 min.	ASTM D-1493
Turbidity Of Melt, APHA	1 max.	HC 390A-80*
Iron, ppm	0.5 max.	WT-2*
Water, Wt%	0.07 max.	ASTM D-1631
Non-Volatile Residue, Wt%	0.05 max.	ASTM D-1353
Impurities By GC		
Alpha Methyl Styrene, ppm	100 max.	
2-Methyl Benzyl Furan, ppm	25 max.	
Di-Methyl Benzyl Alcohol, ppm	100 max.	
Acetophenone, ppm	5 max.	

Source: Monsanto

TABLE 43

UNITED STATES PRODUCTION OF PHENOLICS

Year	1,000 tons
1979	1700
1980	1200
1981	1200
1982	1000
1983	1300
1984	1400
1985	1400

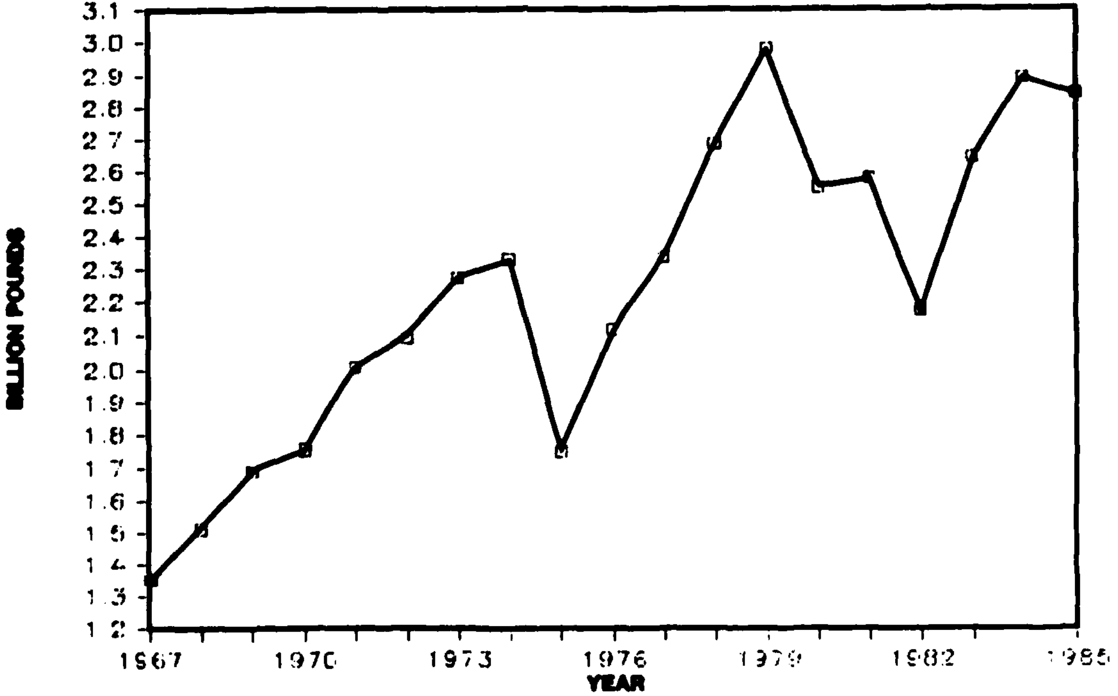


FIGURE 31

PHENOL PRODUCTION

Prices

A history of list prices for phenol is given in Figure 32. These prices are on a freight equalized basis, that is, including freight, assuming average transportation costs. Prices paid by large-volume consumers are somewhat lower. Contacts with industry in February, 1987 suggested a current market price in the range of $0.21 to $0.25 per pound. However, by late April, 1987, prices had jumped to $0.30 per pound.

Consumers

Phenolic resins consume about 40 percent of the phenol produced in the United States. Industrial chemicals, drugs and caprolactam (a nylon precursor) account for the remainder of phenol consumption.

The ultimate markets for phenol are heavily dominated by durable products, (Figure 33). Resins and adhesives derived from phenol are used in automobiles and housing, with adhesives accounting for about 50 percent of phenolic resin usage.

Large regional markets for phenol are present on the Gulf Coast, East Coast, West Coast and Midwest. If we assume that the maximum phenol production from Great Plains would be about 35 million pounds per year, this would represent less than 10 percent of Gulf Coast nameplate capacity. Thus there should be no problem with finding a market provided specifications can be met.

The heterogeneity of the Great Plains crude phenol stream makes the reaction of polycondensation with formaldehyde of little value as a means of utilizing total phenols. Polycondensation of total phenols with formaldehyde yields products that contain low-molecular weight compounds and is therefore unsuitable for the production of thermosetting resins, varnishes, etc.

Monatomic phenols which consist of phenol homologs and also contain naphthol homologs and heterocyclic phenols are suitable for the production of varnishes and surface-active agents.

The top five producers of phenolic resins are Borden Chemical, Georgia Pacific, Monsanto, Owens-Corning Fiberglass, and Reichhold Chemicals.

Producers

Almost all current phenol production is synthetic phenol, and most of that is derived from cumene. Natural phenol production from coke ovens accounts for an insignificant percentage of current production. Some natural phenol is derived from petroleum.

In the cumene process, cumene $[C_6\text{-}CH(CH_3)_2]$ is prepared by alkylating benzene with propylene. Purified cumene is oxidized with air to form cumene hydroperoxide. The hydroperoxide in the presence of sulfuric acid then splits into acetone and phenol. Although there are several other routes from benzene to phenol the cumene route has been completely dominant. Most non-cumene-based phenol plants have gradually closed as new cumene plants came onstream.

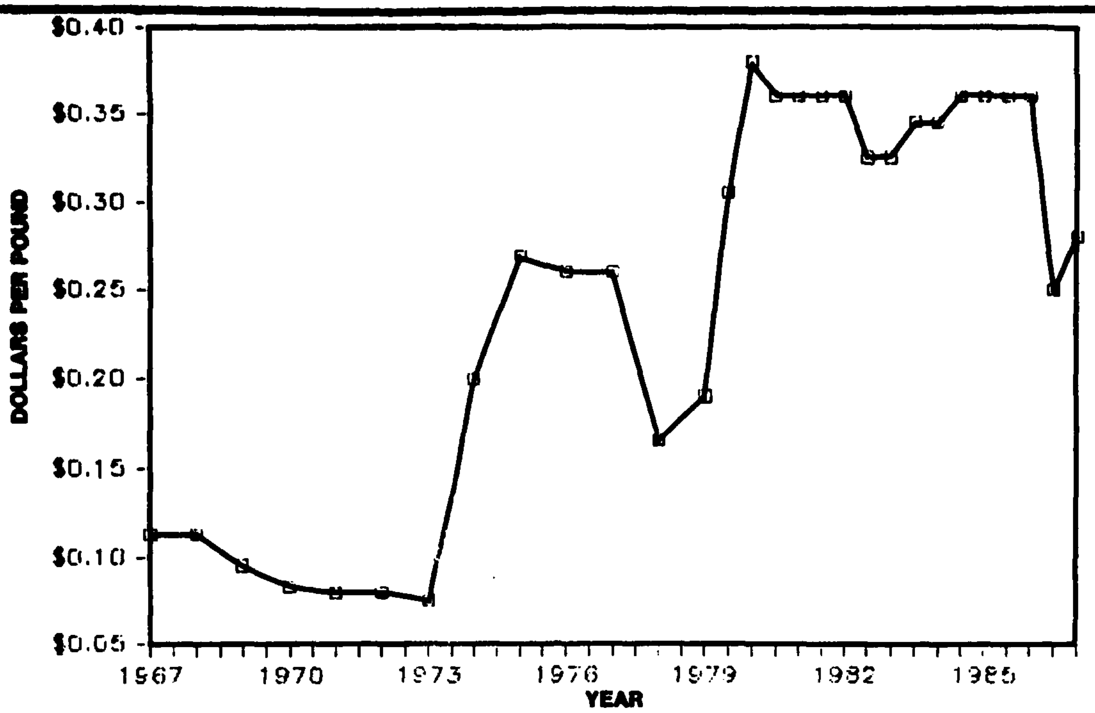


FIGURE 32

PHENOL PRICES
SYN, TANKS, FRT. EQUALD

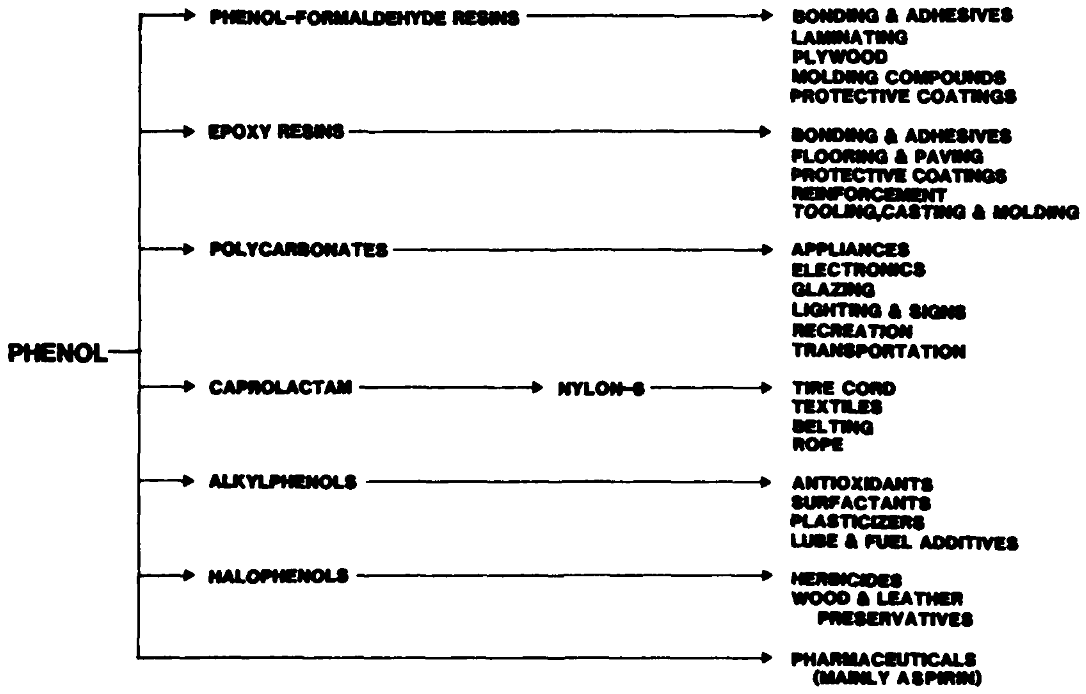


FIGURE 33

ULTIMATE MARKETS FOR PHENOL

Very little phenol is imported. The largest United States producers of synthetic phenol, their plant locations and capacities, are listed in Table 44. Some 900 million pounds of capacity was closed between 1981 and 1987, but Aristech has recently announced plans for expansion.

Most natural phenol originates from petroleum caustic wash streams. Phenols are generated as coproducts during catalytic cracking of petroleum. The effluent stream of the cracker is washed with sodium hydroxide, primarily to remove mercaptans and other organic sulfur compounds. The caustic wash operation simultaneously extracts phenols and cresols as the sodium salts. Natural phenol producers process the caustic wash streams to regenerate and recover phenol, cresols, xylenols, and mixtures.

Table 45 lists United States producers of natural phenol and their capacities. In comparison with Table 44, the total production of natural phenol is an insignificant market factor.

Market Structure

All of the major phenol producers listed in Table 44 use most of their output for captive production of materials such as phenolic resins, bisphenol A, Caprolactam, salicyclic acid, 2,4-D, pentachlorophenol, etc. Most of them also produce excess material for merchant sale.

The merchant phenol market has been subject to violent price swings, as evident in Figure 32. In order to protect both sides against these swings, long-term contracts between buyers and sellers may be used. Because of the captive production situation only a small percentage of the total phenol market is accessible to independent producers. In spite of the small fraction of the phenol market which is non-captive, the amount of phenol represented by this fraction is large with respect to the potential production from Great Plains.

Market Outlook

As seen in Figure 31, phenol has shown long-term growth interrupted by large cyclic ups and downs. Phenol's primary end uses are in the manufacture of durable goods and the housing and construction industry, which are strongly sensitive to economic cycles. Because the traditional phenol markets are technologically mature, future demand growth is expected to be nominal, probably little more than overall GNP growth. Phenolic resins are the oldest class of plastic materials in commercial production, having been first introduced in 1910.

The most valuable property of phenolic resins is their outstanding performance in adhesive applications. The largest single use is in making exterior grade plywood. A major market for various pressed-wood-fragment products had been expected to develop in finished siding for housing. Instead, many problems and lawsuits occurred as panels have warped in high humidity areas. One phenol end-use showing strong growth has been the manufacture of bisphenol A, an intermediate in the production of epoxies and polycarbonates. A growth rate of 7-8 percent is expected for bisphenol A.

Future phenol prices will be related to both the cost of feedstock and the cost of manufacturing. A new cumene production process developed by Monsanto

TABLE 44

MAJOR PRODUCERS OF SYNTHETIC PHENOL

Company	Location	Capacity, MMlb/yr
Allied Chemical	Frankford, PA	600
Aristech	Haverhill, OH	500
Shell Chemical	Deer Park, TX	500
Dow Chemical	Oyster Creek, TX	500
General Electric	Mount Vernon, IN	400
Georgia Pacific	Plaquemine, LA	300
Clark	Blue Allen, IL	?
Texaco/Getty	Eldorado, KS	?
Kalama Chemical	Kalama, WA	?

TABLE 45

UNITED STATES PRODUCERS OF NATURAL PHENOL

Company	Location	Capacity, MMlb/yr	Source
Merichem	Houston, TX	20	Petroleum
Diamond Shamrock	Tuscaloosa, AL	10	Petroleum
PMG	Santa Fe Springs, CA	8	Petroleum
Koppers	Follansbee, WV	8	Petroleum, coal tar
Northwest Petrochemical	Anacortes, WA	2	Petroleum

and Lummus Crest in 1984 is said to provide a cost saving of about a penny per pound. The cost of benzene feedstock accounts for about half the total cost of phenol (propylene, the other feedstock component, is essentially 100 percent recovered as LPG). Because of the phaseout of leaded gasoline in 1986, demand for benzene as an octane improver in gasoline is increasing at the same time as the petrochemical demand for benzene is surging. These factors are causing significant price increases for benzene. This in turn, must impact the cost of synthetic phenol. For the short term, some see additional phenol price increases of $0.10 per pound or more as likely. For the longer term, after benzene prices have stabilized around a new supply/demand balance point, a phenol price of about $0.28 per pound is expected.

RUBBER PROCESSING OIL

Definitions and Specifications

The synthetic rubber industry uses a wide variety of processing oils. There are two broad classes of rubber processing oils: aromatic and naphthenic. The aromatic oils are used mostly in tire production and the naphthenics are used in lubrication.

Four general types of processing oils are defined by ASTM as shown in Table 46. This table simply defines general classes. Actual purchase specifications are prepared by each rubber manufacturer, and may be very detailed. Table 47 is an example of a purchase specification for an aromatic processing oil.

On any new material, compounding tests and factory trials would be required. This procedure could take up to two years and cost $250,000 in the rubber manufacturer's facility before it would be known if a material is acceptable. Because each manufacturer establishes his own specifications some parts of the process might have to be repeated with each client. There would have to be a large financial incentive for the rubber companies to consider such a new source.

Production

Rubber products shipments are highly dependent on the motor vehicle market. Approximately 85 percent of its shipments go to passenger cars, trucks, and buses. Other markets include aircraft, agricultural, industrial, motorcycle, and bicycle uses. Demand for rubber processing oils fluctuates in direct linkage with rubber production. Estimated current demand is about 68 million gallons per year (4,400 barrels per day) of naphthenic type oils and 90 million gallons per year(5,800 barrels per day) of aromatic oils. Thus the total Great Plains tar oil stream would represent a significant percentage of the total market in this area.

Prices

Because they are sold to detailed specifications and are not fungible commodities, rubber processing oils have not fallen in price in direct proportion to crude petroleum prices. Recent prices (dollars per gallon) are estimated as follows:

Type	1985	1986	Early 1987
Aromatic	0.50-0.95	0.65	<0.50
Naphthenic	1.00-1.25	1.00-1.05	<0.90
Paraffinic	1.15-1.25		

Consumers

The major consumers are tire manufacturers, who are located mostly in the Midwest and East. The largest single consumer is probably Goodyear, with plants in Alabama, Kansas, North Carolina, Oklahoma, Tennessee and Texas.

Market Outlook

The rubber industry faces stable or declining demand for new vehicles and tires.

According to the International Institute of Synthetic Rubber Producers total 1986 consumption fell an estimated one percent from 1985. Flat demand is predicted for 1987 and the next five years. The Institute's forecast through 1991 shows a compounded annual growth rate of only 0.3 percent -- considerably below gross-national-product projections of 2.8 percent per year for the same period.

The North American tire industry is expected to show little or no growth because of increased imports of tires and longer tire life. The industry has shifted to higher-value, longer-lasting radial tires. More than 20 older tire plants have closed. Employment in the rubber tire industry dropped form 114,000 in 1977 to 66,500 in 1985.

However, demand for specialty rubbers has grown as markets have developed for new automotive applications. Performance requirements in automotive and other applications have forced the substitution of specialty rubbers for general-purpose rubbers and rubbers have been increasingly alloyed with plastics to form new materials. Growth areas include roofing and oil additives, plus new products created from alloys of rubber and plastics.

Because rubber processing oils are derived from petroleum, their prices should eventually be a function of world oil prices. A near-term decline in prices should be expected.

TABLE 46

SPECIFICATIONS FOR RUBBER PROCESSING OILS

		Maximum Percent Allowed		
Type	ASTM Class	Asphaltenes	Polar Compounds	Saturates
Highly Aromatic	101	0.3	25	20
Aromatic	102	0.5	12	35
Naphthenic	103	0.7	6	65
Paraffinic	104	0.1	1	65*

*Minimum percentage

TABLE 47

TYPICAL PURCHASING SPECIFICATION FOR AROMATIC PROCESSING OIL

	Limits	ASTM Test Method
Appearance	Dark colored oil	---
Specific Gravity	0.985-1.008	D1298
Saybolt Viscosity	115-150 SUS	D88
Volatile Matter	0.8 percent maximum	D972
Neutralization No. (Mg KOH/g Oil)	1.5 maximum	D664
Aniline Point, °C	29.4-51.7	D611
Flash Point, °C	204.4 minimum	D92
Pour Point, °C	+29.4 maximum	D97
Refractive Index	1.065-1.074	D2159
Viscosity Gravity Constant	0.930-0.960	D2501
Copper and Manganese	Nil	
Asphaltenes	0.10 percent maximum	D893
Resins (Polar Aromatics)	8.0-16.0	D2007
Aromatics	64.0-80.0	D2007
Saturates	10.0-22.0	D2007

TAR CRUDE

Definitions, Specifications

Tar and tar crudes are basically the materials which come directly from coke plants and are marketed in this form. There are few end-users for tar crudes in their original form; therefore purchasers are mainly tar processors who fractionate the material into end products. They will be interested in buying raw tar only if they can make specification grade products from it.

Production

The production of crude coal tar in the United States began a long decline in about 1965 (Figure 34). The data show a modest rebound in 1984. Unfortunately the Energy Information Administration, United States Department of Energy, discontinued collecting data on coal tar after 1984. The United States International Trade Commission began collecting data for the 1986 year, but at the time of this writing, those data were not yet available.

Prices

There are no published prices for tar crudes, perhaps because of the variability of the product.

Prices for grade RT-12 coal tar, a processed product, have been stable at $1.05 to $1.25 per gallon over the last three or four years.

Consumers

Major purchasers of raw coal tar are distillers who separate the tar into pitch plus creosote. At present, only the pitch fraction is in demand. The creosote market is over-supplied. Purchasers of raw coal tar are Reilly Tar and Chemical, Allied Chemical, and Koppers Company.

Producers

Locations of producers of tar crudes are shown in Figure 35. Basically, these are metallurgical coke plants for the steel industry. One of the largest single producers is Allied Chemical, which produces 80-90 million gallons per year, or about 25 percent of the total market.

Market Structure

Independent coal tar refiners provide part of the market for tar crude. Some producers of tar crude, such as Allied, also process additional material obtained from other producers.

Although a number of different chemicals were at one time extracted from coal tar, that number has steadily dwindled. Even when the industry was strong, the "chemical" products accounted for only about 10 percent of the tar. The remaining 85 percent (allowing for liquor and distillation losses) was composed of the tar oils and pitch. Historically, the profitability of the

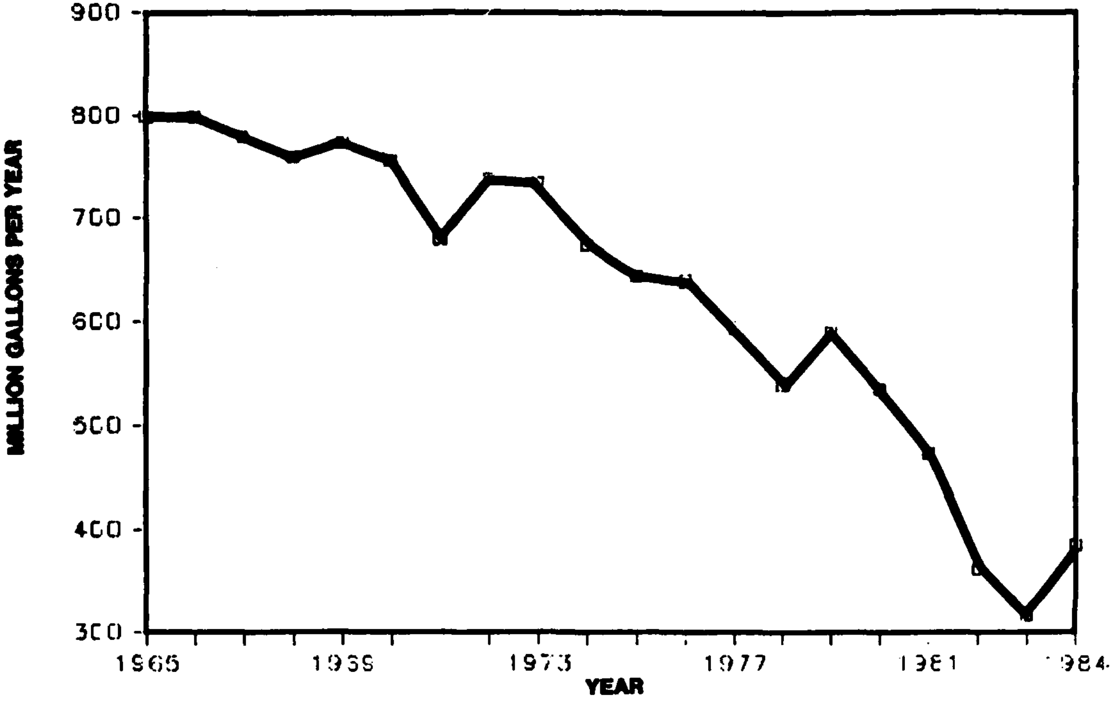


FIGURE 34

CRUDE COAL TAR PRODUCTION

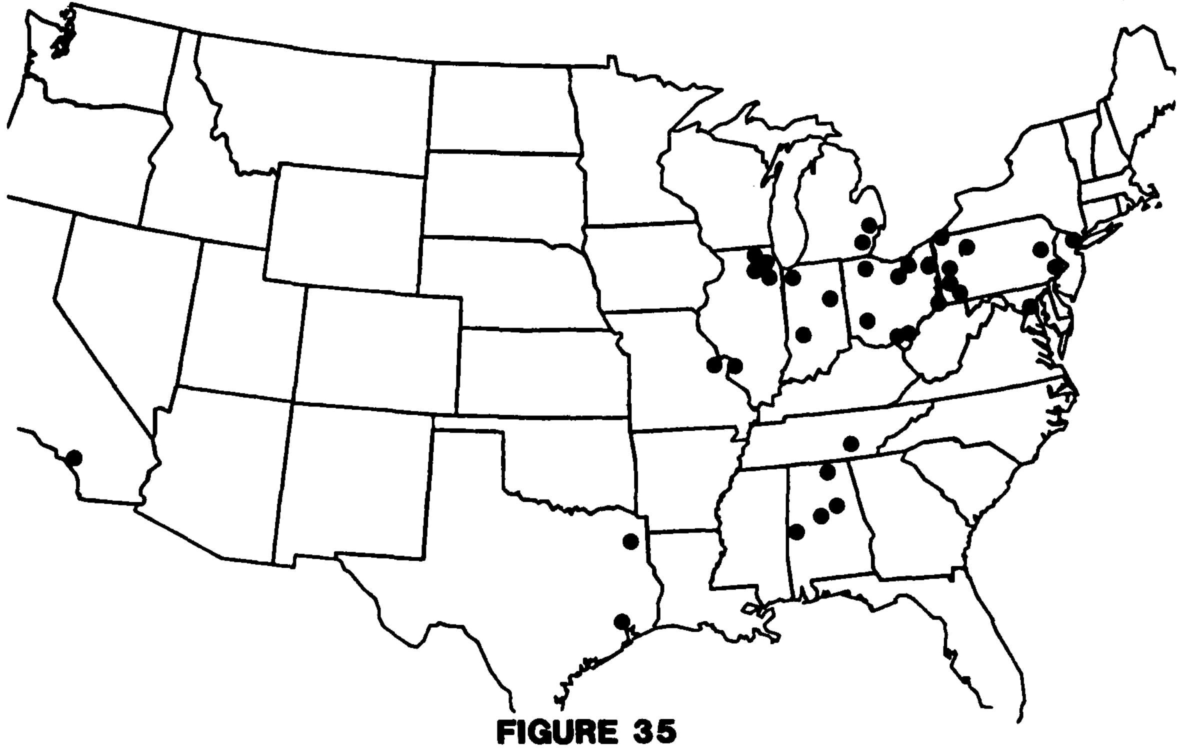


FIGURE 35

PRODUCERS OF TAR AND TAR CRUDES

chemicals production was never high enough to pay for the total recovery operations. Profitable operation depended on the sale of the bulk tar oils and pitch. The oils could be blended to give creosotes and cut-back oils for pitch.

Before 1960 there were a large number of coal tar distillers in the United States. By 1980, they had been reduced to a handful, with Koppers, United States Steel, and Allied Chemical accounting for more than 85 percent of total production. Since 1980, the production of chemicals from coal tar has virtually ceased. The United States Steel Industrial Chemicals Division, for example, shut down its coal tar facilities completely from 1981-1983. When it was reactivated again in 1984, the operation was greatly simplified. Although benzene, xylene and toluene are still produced, everything in the light oil fraction now is simply put into creosote, with the remainder going into electrode pitch or else being burned for fuel.

The market for raw coal tar now depends mostly on the aluminum industry and the demand for pitch. No barriers to entry in this market are known, if material suitable for the market can be provided.

Market Outlook

The market outlook for crude coal tar features both declining supply and declining demand. Supply is determined by the state of the domestic steel industry. All signs point to a continuing shrinkage of the industry, due to a combination of a less steel-intensive economy and competition from overseas. Demand is determined by the state of the aluminum industry, which faces strong competition from overseas. On balance, the steel industry's problems seem greater than those of the aluminum industry. This leads to a prediction that coal tar supplies for pitch production will be somewhat short of demand and prices should remain firm.

PITCH

Definitions and Specifications

Most organic substances, when pyrolized, yield dark-colored viscous liquids termed tar and pitch. The differentiation between these terms is not precise. If the liquid is of relatively low viscosity at ambient temperature, it is designated as a tar. If it is very viscous, semisolid or solid, it is designated as a pitch. When crude coal tar is distilled to yield first a chemical oil fraction, then a creosote fraction, the residue is called coal tar pitch.

Coal tars are extremely complex mixtures, consisting mostly of aromatic hydrocarbons ranging from benzene and alkylbenzenes to compounds containing as many as 20 fused benzene rings. Heterocyclic compounds containing oxygen, sulfur and nitrogen are present, usually with only one heteroatom per ring system. Low temperature tars, such as the Great Plains tars, differ strongly from coke oven tars. The latter contain relatively small amounts of nonaromatic hydrocarbons and relatively small amounts of phenols. The phenols are present mostly in the form of phenol, cresols, xylenols and naphthols distilling up to 300 °C. Low temperature tars, on the other hand, contain much higher proportions of alkylphenols, and the content of unsubstituted ring structures is relatively small. Coke oven tars, when distilled, yield 55-60 percent pitch, whereas low temperature tars (that is, the total tar, not just the tar oil fraction) may yield no more than half as much.

Because coal tars and pitches contain several hundred individual components, it is not possible to create specifications based on chemical composition. Rather, market specifications are based mostly on physical properties. The most common specifications for pitch used as electrode binder are the specific gravity, the softening point, a minimum C/H ratio, maxima for ash content, moisture content, volatile matter, quinoline insolubles, toluene insolubles, and viscosity. Table 48 lists some typical values. Coal tar pitch for other uses is mostly sold to individual users' specifications. Pitch intended for roofing and waterproofing is covered by ASTM D450-71, and hot-applied tar-based pipeline enamels are covered by American Waterworks Association specification C203-73.

The largest current market for coal tar pitch is as a binder for the electrodes used in aluminum smelting. However, the specifications for electrode binder pitch, including high C/H ratio, high coking value and high beta-resin content, effectively rule out unmodified pitches from low temperature tars. Experiments have been tried with air blowing of lignite tar to make specification binder pitch, but these were unsuccessful.

Production

The production of crude coal tar in the United States began a long decline in about 1965 (Figure 34). The data show a modest rebound in 1984. Unfortunately the Energy Information Administration, United States Department of Energy, discontinued collecting data on coal tar after 1984. The United States International Trade Commission began collecting data for the 1986 year, but at the time of this writing, those data were not yet available.

TABLE 48

TYPICAL PROPERTIES OF PITCH BINDERS USED IN ANODES IN THE ALUMINUM INDUSTRY

	Prebaked Anodes	Continuous Anodes
Softening Point, °C		
Cube-In-Air	105-115	
Cube-In-Water		85-90
Specific Gravity, at 25/25 °C	1.28-1.31	1.25-1.29
Quinoline Insolubles, %	5-18	5-15
Toluene Insolubles, %	20-35	15-25
Ash, % (Max)	0.3	0.3
Moisture, % (Max)	0.1	0.1
Sulfur, % (Max)	0.5	0.5
Conradson Carbon (Min)	57	50

Production of tar pitch would be expected to be correlated with overall coal tar production, as it is not practical to convert pitch into other products. However, coal tar producers can choose between burning the pitch for fuel, or selling it as a product. Figure 36 shows recent production history for coal tar pitch. The reporting basis for these data is inconsistent, some years being reported as total pitch, some years as hard pitch only, some years as sum of soft, medium and hard pitch, and some years simply as pitch with no qualifying terms.

Prices

Figures 37 and 38 show the pricing history for two categories of coal tar pitch. The prices for industrial liquid, Figure 37, appear to be close to the overall average price calculated from United States International Trade Commission data. Industry contacts indicate that prices have been fairly stable at these levels for 3 or 4 years. However, long flat periods followed by sharp changes, such as seen in Figure 38, indicate that the data are based on list prices rather than actual transactions. Such data may be badly out of date at any point in time. A rising price trend (Figure 38) in the face of declining production indicates that production (availability) is driving prices rather than vice versa. Pitch production is declining for reasons unrelated to prices, with a resulting upward pressure on prices.

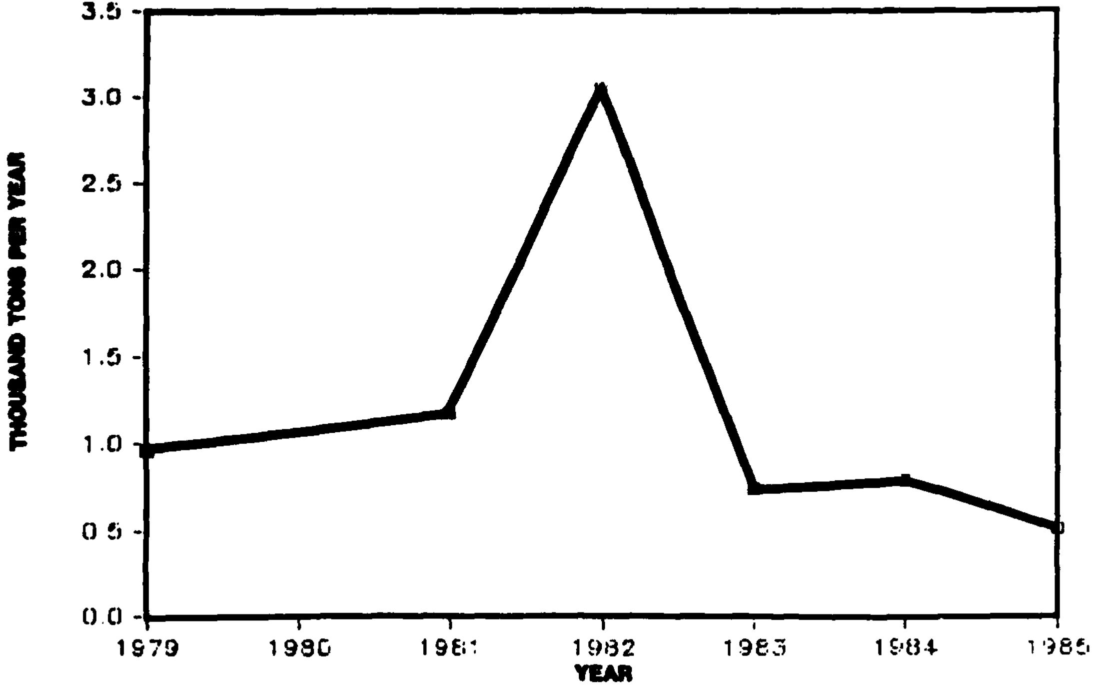


FIGURE 36

PITCH OF TAR PRODUCTION

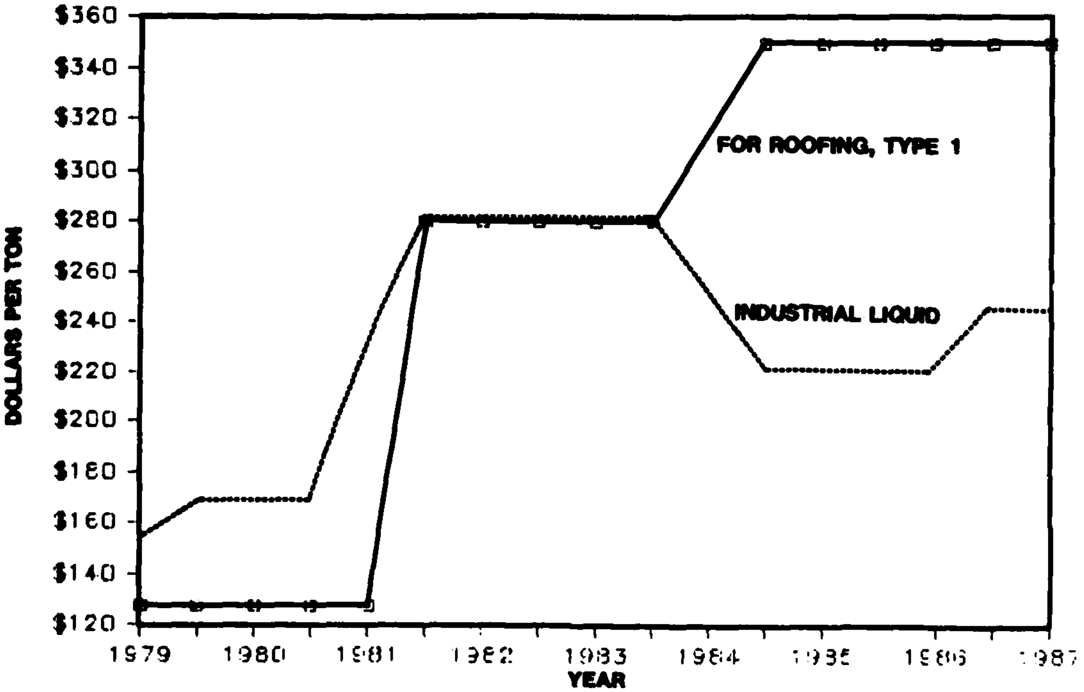


FIGURE 37, 38

COAL TAR PITCH PRICES

Consumers

The major outlet for coal tar pitch in the United States is the binder for electrodes used in aluminum smelting. Older smelters use Soderberg furnaces which incorporate continuously forming electrodes from a mixture of about 70 percent petroleum coke or pitch coke and 30 percent of a medium-hard coke oven pitch. The paste is added to the top of the electrode well, and as it slowly moves downward is first baked into a hard electrode and then consumed in the electrolytic smelting process. Newer smelters use prebaked electrodes requiring less pitch (18 percent) for binder.

Table 49 and Figure 39 give the locations of aluminum smelters. Consumption of binder pitch is estimated to be on the order of 0.12 ton per ton of primary aluminum. At current aluminum production rates of 3.4 million tons per year, this translates to a pitch demand of over 400,000 tons per year. This accounts for most of the pitch production reported to the International Trade Commission.

Other minor uses for coal tar pitch include binder for electrodes in electric arc steel furnaces (in aluminum smelters the carbon electrodes participate chemically in the reduction process and are therefore consumed at much higher rates than in steel furnaces), binder for briquettes, adhesive for membrane roofs, feedstock for coke, impregnant for pitch-fiber pipes, binder for foundry cores, sealant for dry batteries, and raw material for clay pigeons. Roofing pitch is the second largest use after electrode binder pitch.

Producers

Table 50 and Figure 40 give the locations of companies reporting production of soft medium or hard coal tar pitches in 1985.

Market Structure

Coal tar pitch is produced and sold both by the primary coke oven operators and by intermediate tar distillers who purchase crude coal tar and sell pitch to the aluminum smelters and anode manufacturers. The intermediate tar distillers currently have a shortage of good pitch feedstock and would welcome new sources.

Market Outlook

The electrode pitch market is of course dependent upon the market for aluminum. The United States is the world's largest consumer on both an absolute and a per capita basis, but per capita consumption has been flat for 10 years (Table 51).

United States aluminum producers have not been faring well of late. After maintaining almost flat primary aluminum smelting capacity of five million tons per year from 1974 to 1984, primary aluminum capacity fell in the United States to 4.4 million tons in 1985. Production of metal followed this trend and was reduced to 3.5 from 4.1 million tons.

TABLE 49

LOCATIONS OF U.S. ALUMINUM SMELTERS
(As Of January 1, 1986)

Company	Location	Status
Reynolds	Listerhill, AL	Closed
Revere	Scottsboro, AL	Closed
Reynolds	Arkadelphia, AR	Closed
Reynolds	Jones Mills, AR	Closed
Alcoa	Evansville, IN	
Alcan	Sebree, KY	
National	Hawesville, KY	
Kaiser	Chalmette, LA	Closed
Eastalco	Frederick, MD	
Noranda	New Madrid, MO	
Columbia Falls	Columbia Falls, MT	
Alcoa	Massena, NY	
Reynolds	Massena, NY	
Alcoa	Badin, NC	
Ormet	Hannibal, OH	
Reynolds	Troutdale, OR	
Martin Marietta	The Dalles, OR	Closed
Alumax	Mt. Holly, NC	
Alcoa	Alcoa, TN	
Consolidated	Johnsonville, TN	Closed
Alcoa	Rockdale, TX	
Alcoa	Palestine, TX	Closed
Reynolds	Corpus Christi, TX	Closed
Alcoa	Vancouver, WA	Closed
Alcoa	Wenatchee, WA	
Reynolds	Longview, WA	
Kaiser	Spokane, WA	
Kaiser	Tacoma, WA	
Comalco	Goldendale, WA	
Intalco	Bellingham, WA	
Kaiser	Ravenswood, WV	

Source: United States Bureau of Mines, Primary Aluminum Plants, Worldwide

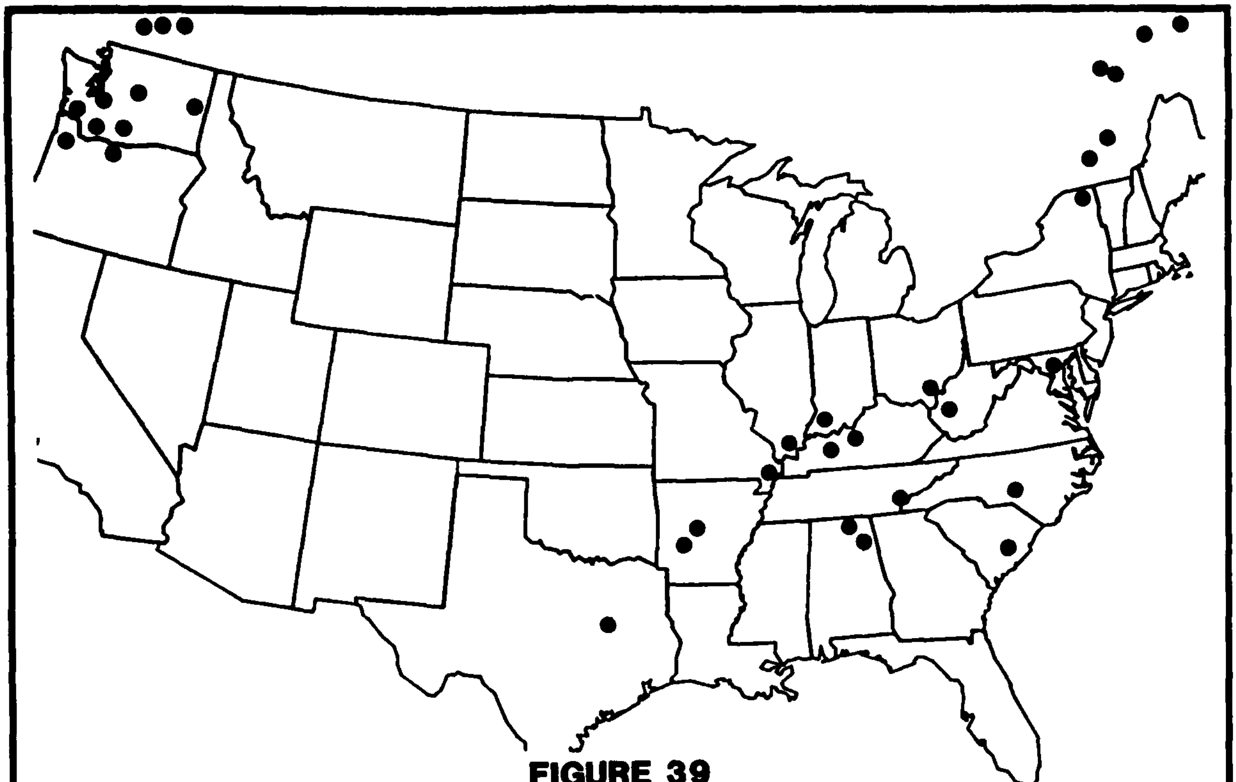


FIGURE 39

ALUMINUM SMELTER LOCATIONS

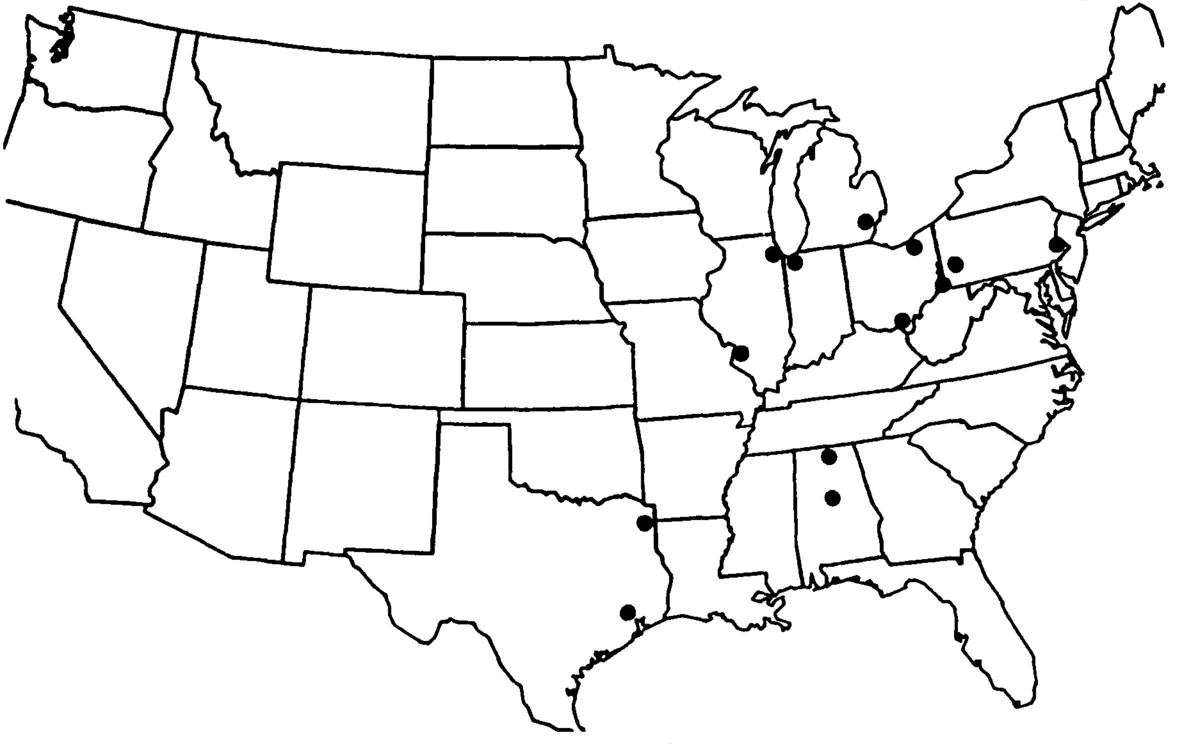


FIGURE 40

COAL TAR PITCH PRODUCERS

TABLE 50

LOCATIONS OF COAL TAR PITCH PRODUCERS IN THE UNITED STATES

Company Name	Location
Allied Chemical	Birmingham, AL
Allied Chemical	Detroit, MI
Allied Chemical	Ironton, OH
Coopers Creek	W. Conshohocken, PA
Koppers	Chicago, IL
Koppers	Follansbee, WV
Koppers	Houston, TX
Koppers	Woodward, AL
Reilly Tar and Chemical	Cleveland, OH
Reilly Tar and Chemical	Granite City, IL
Reilly Tar and Chemical	Lone Star, TX
United States Steel	Clairton, PA
United States Steel	Gary, IN

TABLE 51

UNITED STATES CONSUMPTION OF ALUMINUM

(Pounds Per Person Per Year)

1974	60.4	1979	65.8
1975	44.9	1980	56.8
1976	57.1	1981	55.2
1977	60.3	1982	51.0
1978	65.9	1983	57.7
		1984	59.3

Source: The Aluminum Association

All of the major producers have revealed their intention to cut back primary production to meet only their own demand or else to diversify into other business areas offering higher return. Recent closures are noted in Table 49.

In contrast to the United States picture, overseas producers with either low-cost electricity or government support continue to add to capacity. Expansions or new facilities are under way in Argentina, Brazil, Canada, Mexico, Venezuela, Norway, Iceland, Australia, Bahrain, Dubai and others. Low electric power costs are the driving force for aluminum industry relocations. In Australia, the aluminum producers are obtaining new power contracts for 15 mills/kWh, in Brazil for 18 mills/kWh, and in Canada for less than 20 mills. On the other hand, United States producers outside the Pacific Northwest may be subject to rates of 28-30 mills/kWh or more.

In summary, although aluminum demand is expected to continue to increase worldwide, firm electricity prices of less than 20 mills/kWh are required for an aluminum smelter to compete in today's worldwide market. United States aluminum capacity is therefore likely to continue to decrease, and along with it, the demand for electrode pitch.

PAVING COMPOUNDS

Definitions and Specifications

Coal tar and petroleum asphalt are both used as binders in road construction. There is a great deal of confusion over terminology.

Strictly speaking, bitumen is the residue of crude oils after removal of volatile components, by either natural or artificial processes. Asphalt, on the other hand, is a mixture of bitumen and mineral matter, produced either in nature or by artificial means. Casual usage in the United States, however, applies the term "asphalt" to either asphalt or bitumen. The residues from coal tar distillation are properly called pitches or tar pitches to distinguish their origin. In common usage, tar and pitch are used interchangeably.

Various grades of road tars may be made either by the fractional distillation of crude coal tar, or by blending different refined coal tars, or by blending base pitch with a coal-tar derived flux oil.

In the fractional distillation process, after preheating and dehydration of crude tar, progressively higher boiling range components are removed until a residue of the desired consistency is obtained. In principle, the process is the same as that used to produce coal-tar pitch, except distillation is normally carried out at near atmospheric pressures instead of under vacuum. Distillation temperatures and duration times are controlled to yield road tar of the required viscosity for a particular grade.

Grades of tar have been defined ranging from RT-1 through RT-14. The most widely used paving grade is RT-12.

Petroleum-derived "asphalt" and coal-derived "road tar" can both be used to form an asphaltic concrete type of paving material by mixing with gravel, crushed rock or other aggregate. Although still used in Europe, coal tar has been almost completely abandoned for road construction in the United States. Part of the reason is probably due to lack of availability and part is due to differences in road construction technique. In the United States the base courses and final course are designed to flex slightly under large loads. Asphaltic concrete made from petroleum bitumen is able to yield and recover. Coal tar is more brittle, and requires a rigid under-base.

Tables 52 and 53 illustrate the wide differences in properties. It is not possible to substitute one for the other, and road tar is not considered a viable product today.

Mobil has recently patented a process for making a road paving material by mixing used tires, coal-tar pitch and fluid-catalytic-cracking bottoms. However, the process is not commercial.

A potential application could lie in asphalt recycling agents. These agents are used to dissolve and recondition old asphalt paving which is then respread on the road. Again, there is no commercially established product, and therefore no further consideration will be given in this study.

Work with asphalt derived from shale oil has shown that the nitrogen compounds in shale oil asphalt have superior resistance to moisture damage and could therefore be useful as "anti-strip" agents. These agents improve the bond between the bitumen and the aggregate in asphaltic concrete. It may be possible that the nitrogen compounds in the Great Plains tar oil could perform the same function. This is only speculative, and no market evaluation was attempted.

TABLE 52

COMPARISON OF ROAD TAR AND PETROLEUM ASPHALT

Material Type: Grade:	Asphalt Cement AC-10	Road Tar RT-12
Elemental Analysis, Percent:		
C	85.8	92.2
H	9.7	5.2
N	0.6	1.5
O	0.5	1.0
S	2.8	0.6
C/H Atomic Ratio	0.74	1.49
Molecular Weight, (Number Average)	1,030	420
Carbon Atom Distribution: (Percent of Total Carbon)		
Aromatic Carbon	34	80
Naphthene Carbon	23	15
Paraffin Carbon	43	5

TABLE 53

COMPARISON OF PHYSICAL PROPERTIES OF ROAD TAR AND PETROLEUM ASPHALT

Material Type:	Asphalt Cement	Road Tar
Grade:	AC-10	RT-12
Original Material:		
Viscosity		
140 °F, Poises	1,057	133
275 °F, Centistokes	341	36
77 °F, (Initial), Megapoise	0.64	0.17
Softening Point (R&B), °F	111	104
Penetration		
77 °F (100g, 5S), 0.1 mm	116	Too Soft
32 °F, (200g, 60s), 0.1 mm	22	22
Flash Point (COC), °F	590	380
Solubility In CS_2, Percent	99.9	83.2
Specific Gravity At 77 °F	1.015	1.248
Ductility		
77 °F, cm	100+	Too Soft
60 °F, cm	100+	100+
Thin Film Oven Test Residue		
Weight Loss, Percent	0.1	14.6
Viscosity		
140 °F, Poises	2,478	465,000
275 °F, cS	439	594
Ductility At 77 °F, cm	100+	0.5

NAPHTHALENE

Definitions and Specifications

Naphthalene, $C_{10}H_8$, consists of two fused benzene rings. Pure naphthalene has a melting point of 80.3 °C and a boiling point of 218 °C.

Naphthalene can be recovered either from coal tar or petroleum by-products. The coal tar product is of a lower purity and sells at a discount for that reason. The highest grade of crude coal tar naphthalene has a melting point of 78 °C. An impure grade melting below 74 °C may be sold. A typical coal tar distillation plant produces three fractions with increasingly higher boiling points: chemical oil, creosote, and pitch. Naphthalene is recovered from the chemical oil fraction. The usual procedure is to obtain crude naphthalene product by batch or continuous fractional distillation of the tar acid-free chemical oil. If only creosote and pitch fractions are produced, it may be possible to crystallize naphthalene from the creosote.

The production of naphthalene from petroleum involves two principal steps: production of an aromatic oil in the naphthalene-alkylnaphthalene boiling range by hydroaromatization or cyclization; and dealkylation of such oils either thermally or catalytically. The naphthalene that is produced is recovered as a high quality product and usually by fractional distillation.

Production

Recent data on coal tar naphthalene production have not been published by the International Trade Commission due to the small number of companies reporting. However, production declined steadily over the period 1968 to 1982, from 526 million pounds per year to 233 million pounds per year.

Production has declined for two reasons: a declining availability of coal tar from the steel industry; and a declining demand for naphthalene to make phthalic anhydride. The production of phthalic anhydride has been the largest use for naphthalene, but o-xylene derived from petroleum has supplanted naphthalene as the preferred feedstock.

Prices

Although demand for crude naphthalene has been shrinking over the past several years, this has been offset by shrinking availability, with the result that prices appear to have held firm (Figure 41). Petroleum naphthalene (phthalic anhydride grade) sells for about $0.08 per pound more than coal-tar-derived material. These prices are from the Chemical Marketing Reporter for the years shown.

There appears to be some doubt about the validity of their prices in recent years due to the use of posted prices and the small number of suppliers in the market. Direct contact with producers indicates that current prices for high purity, refined naphthalene are around $0.31 per pound, while phthalic anhydride grades are $0.16 to $0.23 per pound. Coal-tar-derived material would probably sell at the bottom end of this range.

Consumers

Naphthalene has a wide variety of uses, from insecticides to leather tanning agents, but the majority of naphthalene produced is used in manufacturing phthalic anhydride. Estimated uses of naphthalene in different markets are shown in Table 54.

As noted above, the phthalic anhydride market has been usurped by o-xylene.

Naphthalene is one of the principal raw materials for the insecticide known generically as carbaryl, and more commonly by the trade name Sevin. Union Carbide is the United States producer of Sevin.

Naphthalene is also used by American Cyanamid to make beta-naphthol, an intermediate for dyes, pigments and rubber processing chemicals. American Cyanamid is the only producer.

Naphthalene-based surfactants derived from naphthalene sulfonic acid are used as superplasticizers in concrete formulations made by a number of companies.

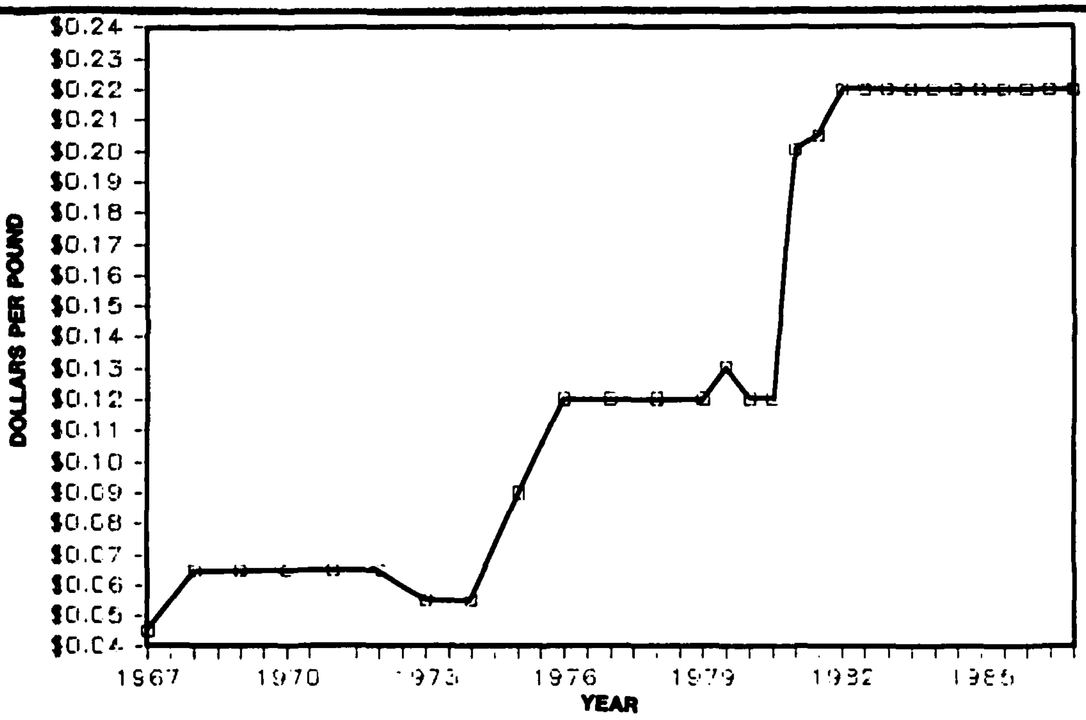


FIGURE 41

NAPHTHALENE PRICES
CRUDE, DOM TANKS, WORKS

Producers

Known United States producers of crude chemical naphthalene in 1985 are listed in Table 55. It may be noted that the listed production capacities are much greater than the estimated production rate. Production is constrained by the availability of raw material. Ashland no longer makes naphthalene, and Texaco (Getty) is now the only producer of high purity material.

Market Structure

The market for merchant naphthalene is thin because much of the production is captively consumed. Only Allied and Koppers appear to be major suppliers on the merchant market. Ashland has recently discontinued production but continues to market naphthalene. They could be a potential buyer for Great Plains naphthalene if a high purity material is produced.

There is considerable uncertainty with respect to the amount of naphthalene in the Great Plains tar oil stream. Various analyses have indicated anywhere from two percent to 15 percent naphthalene. At five percent naphthalene content, potential naphthalene production would be 16 million pounds per year, which would be insignificant with respect to the total market.

Market Outlook

Naphthalene for phthalic anhydride will undoubtedly continue to be replaced by o-xylene as a feedstock. Other uses such as insecticide, tanning agents, moth repellants, etc., are mature, slow-growth or declining markets. The one strong growth area for naphthalene is the surface active agents for concrete admixtures. On the whole, naphthalene demand will continue to decline. Once the decline in demand substantially exceeds the decline in production capacity, it is likely that a large break will occur in the price for merchant naphthalene.

TABLE 54

ESTIMATED U. S. NAPHTHALENE CONSUMPTION

Use	Percent Of Total
Phthalic Anhydride	59
Insecticides (Sevin)	20
2-Naphthol (Dyes, Pigments, Intermediates)	8
Synthetic Tanning (Leather)	6
Moth Repellants	2
Surfactants	4
Miscellaneous	1

TABLE 55

UNITED STATES PRODUCERS OF CHEMICAL NAPHTHALENE
(1985 Data)

Company	Location	Capacity (MMlb/yr)	Source
Allied Chemical	Ironton, OH	75	Coal tar
Ashland Oil	Ashland, KY	90	Petroleum
Getty Oil	Delaware City, DE	100	Petroleum
Koppers Co.	Follansbee, WV	190	Coal tar
Monsanto	Chocolate Bayou, TX	90	Petroleum
USS Chemicals	Clairton, PA & Gary, IN	155	Coal tar
Bethlehem Steel		--	Coal tar
LTV Steel		--	Coal tar
Indiana Gas & Chemical		--	Coal tar
Total		700+	

Source: United States International Trade Commission and industry reports

MISCELLANEOUS USES

Coal Dust Suppressant

Various liquids can be used to control dust emissions during coal handling and shipping. In the Powder River Federal Coal Region (southern Montana and northeastern Wyoming), a heavy oil is used at several mines as a dust suppressant. The oil is delivered to the mines by trucks, and is sprayed onto the coal at the tipple. Other materials have also been tested as dust suppressants, but the heavy oil is preferred because it adds approximately 150,000 BTUs per gallon of oil to the heating value of the coal.

It has been indicated that the amount of oil sprayed on the coal is from 1.5 to 4 gallons per ton. The most commonly quoted figure is 2 gallons of oil per ton of coal. The four coal mines known to have installed oiling systems produce approximately 20 million tons per year. Thus, the demand for heavy oil dust suppressants at these four mines alone could be in excess of 2,600 barrels per day. For the entire region, approximately 115 million tons per year is shipped out of the Powder River.

The use of heavy oil as a dust suppressant in other areas of the country is not common. Unlike other regions, most of the coal produced in the Powder River region is shipped long distances to markets. Powder River subbituminous coal is also subject to more decrepitation and dusting problems than most coals. The specifications for coal dust suppressants are primarily set by the consuming utilities. The oil functions to control dust during handling and shipping, to inhibit moisture loss from or addition to the coal thereby preventing freezing of the coal, to suppress spontaneous combustion, and to prevent decrepitation during shipment. Little is known about the chemical and physical characteristic of oils that contribute to good or poor performance. Oils that have been tested and rejected include: Bunker C, No. 6 fuel oil, and crude oil. It is unknown if Great Plains tar oil could meet performance specifications. Odor would obviously be a problem.

Known specifications for the dust suppressant are given in Table 56.

It is likely that health concerns and odor problems would prevent the use of tar oil in this application. In any event, the selling price is estimated to be not appreciably higher than the price for residual fuel.

Drilling Mud

Oil-based drilling mud is used to solve a variety of problems in drilling oil wells. The major problem is hold instability caused by the hydration of formation clay when water-based mud is used. This causes material to slough away from the walls. Although coal tar liquids might have some favorable performance characteristics in this use, the environmental problems associated with disposing of the mud will prohibit their use. Environmental guidelines for oil-based mud suggest that the base oil should have total aromatics content of less than five percent, and no high molecular weight polycyclic aromatics. Oils which have been used are paraffinic and naphthenic types. Phenols would not be acceptable.

TABLE 56

SPECIFICATIONS FOR COAL DUST SUPPRESSANTS

API Gravity (Degrees)	-5 to +5
Pour Point (F)	40 to 65 max
BS&W	trace to 1% max
Flash Point (F)	230 min to 275
Viscosity @ 100 F (Cst)	700 min to 1,500
Sulfur (Weight Percent)	2.5 to 5 max
Light Ends (% Off @ 500 F)	1 to 5 (10 max)

Methyl Aryl Ethers

It has been suggested that methyl aryl ethers manufactured from coal liquids would be a desirable anti-knock additive for gasoline.

Because phenols are present in coal liquids and are undesirable in fuels, and because destroying the phenols by hydrotreating is expensive, it was proposed to convert the phenols to methyl aryl ethers. Methyl aryl ethers are also knows as anisoles. (Anisole is $C_6H_5OCH_3$). They can be prepared by direct reaction of methanol and phenol.

Compared with the alkyl ethers (e.g. methyl tert-butyl ether, MTBE), the aryl ethers have higher boiling points and densities, and lower octane blending values (Table 57).

The logic put forth for investigating the methyl aryl ethers was that, if coal liquefaction and/or gasification becomes commercially significant, far more phenolics will be produced than can be absorbed by the combined demand of all chemical industries utilizing phenolics. That is certainly not the case with respect to the Great Plains plant and the current outlook for coal conversion. The phenols would have to be extracted first, before reacting with methanol to make the ethers. At the point where phenol is extracted it becomes a saleable product. There are many other products which can be made from phenols if it is desired to extend the manufacturing process downstream. No special attention to methyl aryl ethers is warranted in this study.

Briquette Binder

Coal tars are used as briquette binders in various applications. One possibility in the Great Plains marketing region is the FMC formcoke plant at Kemmerer, Wyoming. This plant makes a metallurgical coke from non-metallurgical grade coal via the FMC Formcoke process. In this process the coal is carbonized, the tar is separated and processed to make a good binder, and then the tar is mixed back with the char and formed into briquettes.

Insufficient pitch binder is obtained from the process itself, so FMC buys additional binder material. Their total binder pitch requirements are about 20,000 tons per year.

Important characteristics for this use are softening point (ring and ball), coking yield (at least 50 percent), quinoline insolubles (20 percent maximum), and mutual solubility with other binder components.

At present, FMC is purchasing only a small part of their binder requirements from the outside, and they are using molasses because it is cheaper than coal tar.

Other

Many examples can be found in the literature of other products which can be made from coal-derived liquids. Notable among these are the many coal tar bases which have not been discussed. Pyridine derivatives of all types can be produced. Specialty solvents, such as 2,4,6-trimethyl pyridine were commercially produced at one time. None of these uses which were examined seem to provide a large enough market opportunity to justify significant development efforts at this time.

TABLE 57

ANTIKNOCK PERFORMANCE OF ETHERS

Compounds	Boiling Point, °C	Density (20 °C), g/ml	Performance Number[a]
Methyl tert-Butyl Ether	54.6	0.7403	143
Ethyl tert-Butyl Ether	71.9	0.7395	144
Isopropyl tert-Butyl Ether	87.4	0.7413	149
Methyl Phenyl Ether	153.6	0.9939	107
Ethyl Phenyl Ether	169.9	0.9651	111
o-Methyl Anisole	171.8	0.9796	82
m-Methyl Anisole	176.6	0.9716	110
p-Methyl Anisole	176.7	0.9701	112

[a] ASTM performance number of 25 volume percent ether in base fuel of 120 rating and containing 4 ml/gas TEL

TRANSPORTATION ROUTES AND OPTIONS

A problem to be faced in marketing certain by-products from the Great Plains plant is the lack of a substantial market in the immediate region. This is illustrated in a general sense by Figure 42, which indicates the fraction of total United States manufacturing activity which takes place in each state. The data are based on United States Census data for value added by manufacturing.

Value added by manufacturing is derived by subtracting the cost of raw materials, parts and components, supplies, fuels, electricity, and contract work flowing into all plants from the total value of shipments out of all plants. It is considered to be the best value measure available for comparing the relative economic importance of manufacturing between geographic areas. Value added by manufacturing ranges from a high of $5,193 per person in Connecticut to a low of $791 per person in Wyoming.

The data in the figure indicate the potential Great Plains disadvantage. Long rail distances would be required to reach a significant fraction of total U.S. manufacturing capability. A 500 mile radius encompasses only about two percent of total United States manufacturing activity:

Distance, Miles	Percent of Value Added Activity Accessed
500	2.0
1,000	15.0
1,500	49.0
2,000	96.0
2,500	98.0

Distances by railroad and highway to cities of interest in the immediate region, and in the nation as a whole are given in Table 58.

REGIONAL PIPELINES

The existing regional product pipelines which serve as transportation links for petroleum products in the Great Plains region are shown in Figure 43. Regional refining centers connected to the pipeline system are also shown in the figure. Major refineries located at Mandan, North Dakota; St. Paul and Rosemount, Minnesota; Casper, Sinclair, and Cheyenne Wyoming; Laurel and Billings, Montana; and Regina, Saskatchewan. Contact with all the major pipeline operating companies in the region suggests that considerable excess capacity is available. Thus the introduction of up to 5,000 barrels per day of refined fuels in this region would probably displace other products through the pipeline system.

Amoco

A 10-inch Amoco products pipeline runs from Mandan, North Dakota through Minnesota to Minneapolis/St. Paul. The line continues to Dubuque, Iowa where it

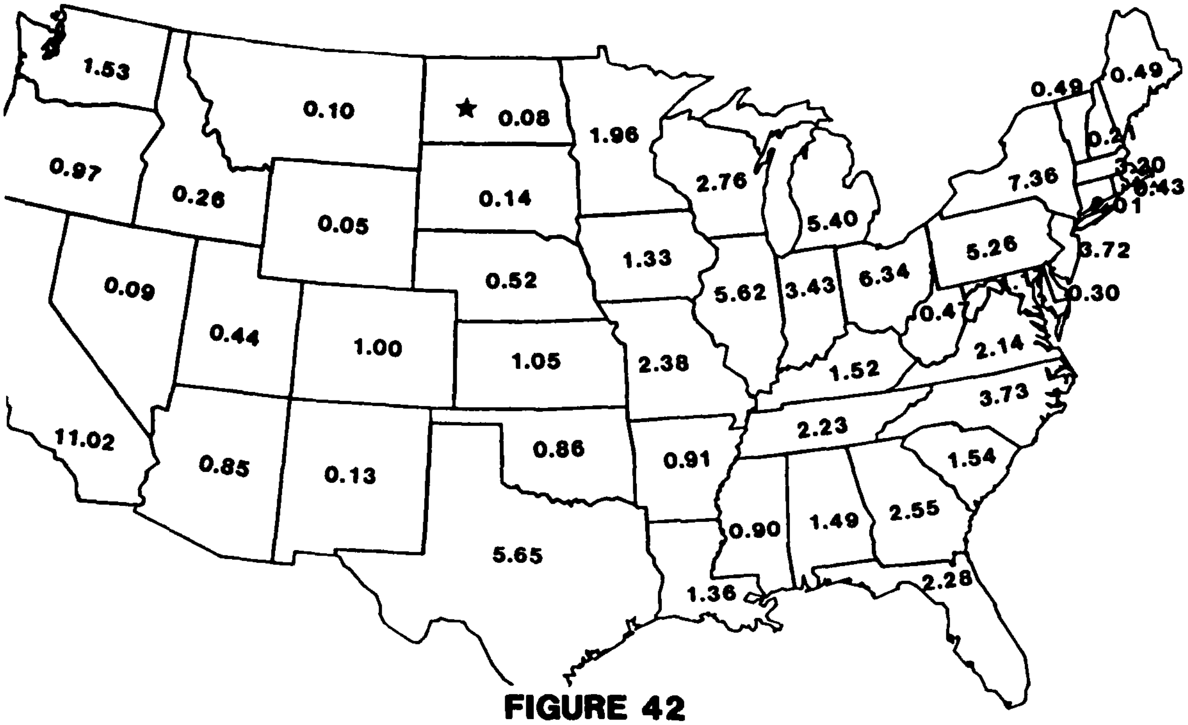


FIGURE 42

PERCENT OF TOTAL U.S. VALUE ADDED BY MANUFACTURING IN EACH STATE

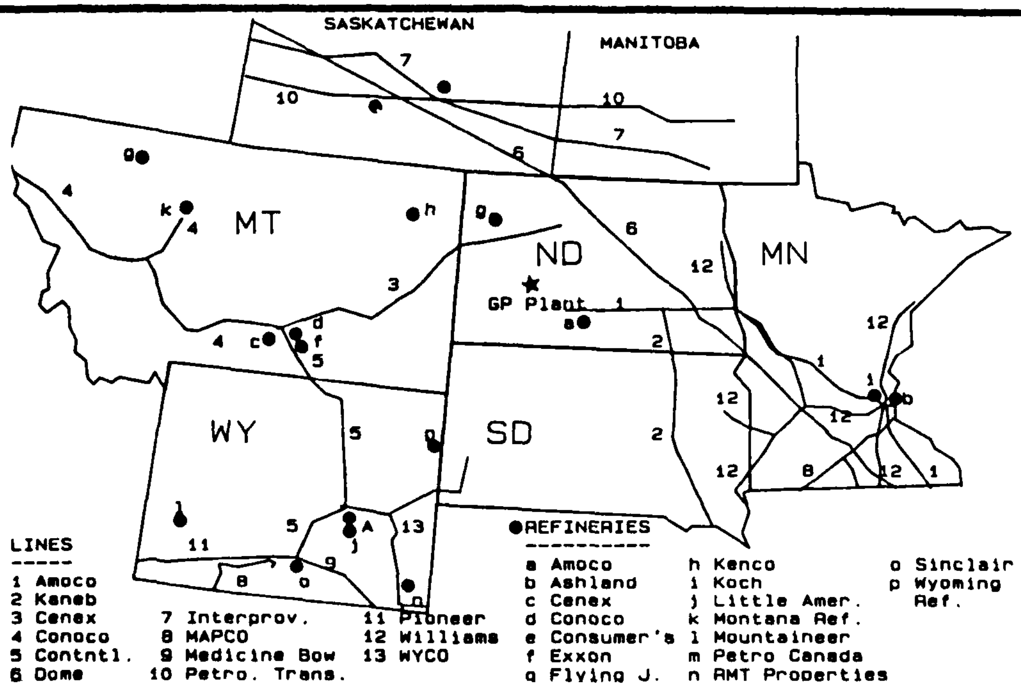


FIGURE 43

GREAT PLAINS REGION PRODUCTS PIPELINES

TABLE 58

DISTANCE FROM BEULAH TO U. S. AND CANADA CITIES, BY RAILROAD AND HIGHWAY, IN MILES

	Distance By Railroad	Distance By Highway
Regional		
Billings, MT	503	405
Grand Forks AFB, ND	344	286
Great Falls, MT (Malmstrom AFB)	738	597
Laurel, MT (Cenex Refinery)	518	420
Mandan, ND (Amoco Refinery)	73	73
Minot AFB, ND	268	105
Rapid City, SD (Ellsworth AFB)	631	325
Regina, Saskatchewan (Consumer's Refinery)	559	413
Winnipeg, Manitoba	503	578
National		
Atlanta, GA	1,635	1,664
Calgary, Alberta	951	739
Chicago, IL	899	915
Cincinnati, OH	1,180	1,214
Cleveland, OH	1,250	1,267
Houston, TX	2,273	1,567
Los Angeles, CA	1,914	1,538
Minneapolis, MN	498	509
New Orleans, LA	1,797	1,652
Philadelphia, PA	1,730	1,704
Pittsburgh, PA	1,381	1,396
St. Louis, MO	1,098	1,120
Seattle, WA	1,378	1,145
Winnipeg, Manitoba	578	417

then splits into two directions. One 10-inch line connects to Chicago and Detroit. The other, a 12-inch line, connects to Kansas City. Information on flows in this line was not available.

Cenex

An eight-inch Cenex pipeline originates at their refinery in Laurel, Montana and flows to Minot, North Dakota. Cenex representatives felt that production of light products by the Great Plains plant would be serious competition for them, and declined to provide their capacity or average daily flow.

Conoco

A 10-inch Conoco products pipeline originates in Billings, Montana and flows to Grant County, Washington. An additional six-inch pipeline connects to this line in Helena, Montana from Great Falls, Montana. Average daily flow is 20,000 barrels per day from Montana to Washington.

An eight-inch Continental products pipeline originates in Billings, Montana and flows to Sinclair, Wyoming. A six-inch Medicine Bow Products Pipeline System pipeline then flows south of Sinclair to Commerce City, Colorado, while an eight-inch Pioneer pipeline, also owned by Continental, connects Sinclair and Salt Lake City.

Flow in the Continental pipeline averages 10,000 barrels per day from Billings to Sinclair. Flow in the Medicine Bow pipeline averages 19,000 barrels per day from Sinclair to Commerce City. Flow in the Pioneer pipeline averages 30,000 barrels per day from Sinclair to Salt Lake City.

Dome

Dome Petroleum has a 12-inch propane line that originates in Ft. Saskatchewan, Alberta and flows southeast through Saskatchewan, North Dakota, Minnesota, and on to Ontario via Illinois, Indiana and Ohio. The flow mostly passes through provinces and states in the Great Plains region, with small deliveries of 3,000 barrels per day in Saskatchewan and 7,000 barrels per day in Minnesota. The flow into Saskatchewan averages 40,000 barrels per day while the flow out of Minnesota averages 30,000 barrels per day.

Interprovincial

A 16-inch Interprovincial products pipeline originates in Edmonton, Alberta and flows in a southeasterly direction into Saskatchewan, Manitoba, and Minnesota. Average daily flows are 125,796 barrels per day from Edmonton to Saskatchewan, 115,103 barrels per day from Saskatchewan into Manitoba, and 61,011 from Manitoba to Minnesota. Interprovincial expects a 30 percent increase of all products moving through this pipeline in 1987.

MAPCO

A 12-inch MAPCO LPG pipeline runs from southwestern Wyoming to Farmington, New Mexico, Texas, and then northeast to Janesville, Wisconsin. The flow from Wyoming south averages 28,000 barrels per day. A second MAPCO line is a two branch line that moves propane at 10,000 barrels per day in one branch and NGL at 10,000 barrels per day in the other. Both lines are six inches in diameter. Direction of flow is north into Minnesota from Iowa.

Petro-Canada

The six-inch Petro-Canada line moves products from just west of the Alberta/Saskatchewan border into Saskatchewan and Manitoba. Average deliveries to Manitoba are 10,700 barrels per day.

Williams

Williams has an extensive products pipeline network in Minnesota. The information is summarized in Table 59. The two six-inch and one 12-inch pipeline that flow from Minneapolis south connect with Des Moines, Iowa, then Kansas City, Missouri and Tulsa, Oklahoma.

Wyco

A 10-inch and an eight-inch Wyco products pipelines connect Casper, Wyoming and Colorado. The eight-inch terminates in Commerce City and the six-inch terminates south of Colorado Springs. Average flow from Wyoming to Colorado is 37,450 barrels per day. Another branch runs from Wyoming to Rapid City, South Dakota at 5,000 barrels per day. A connection with the Cheyenne pipeline runs between Wyoming and Nebraska at an unknown flow rate.

TABLE 59

WILLIAMS PRODUCT PIPELINES IN MINNESOTA

Figure #	Direction	BPD	Size	Capacity (BPD)
1	MN to WS West to East	13,200	8 inch	22,000
2	MN to WS South to North	10,500	8 inch	14,000
3	WS to MN North to South	10,500	8 inch	14,000
4	MN to ND	14,300	8 inch	22,000
5	SD to MN	9,600	8 inch	24,000
6	MN to SD	4,400	6 inch	11,000
7	MN to South of MN	32,000	6,12 inch	80,000

RAILROADS

Figure 44 illustrates the major railroad connections in the Great Plains region. Figure 45 shows the major transcontinental routes to cities outside the immediate region. Mileages from Beulah, North Dakota to regional cities, Air Force bases and refineries were given earlier in Table 58. To obtain shortest distances possible, some of the mileages given involve switching rail line companies. This might not be feasible due to lack of switching arrangements, or unwillingness by the companies to comply.

A significant fact is that the Great Plains region is served by only a single railroad, the Burlington Northern, with only a single route through that region. Thus anyone using the railroad in this area becomes a "captive shipper".

The Staggers Rail Act legislation, passed in 1980, partially deregulated the railroads. Previously, the Interstate Commerce Commission (ICC) assigned routes and authorized rates. Some immediate results of the Staggers Rail Act have been:

Long term contracts now possible
Rail rate increases
Increase railroad management responsibilities

Railroads now have increased flexibility in setting rates. Rates can be increased on a 20-day notice, and reduced on a 10-day notice. The ICC can question a rate if it exceeds 180 percent of the revenues to variable cost ratio.

Investigations by the ICC cannot be performed unless a shipper charges that the railroad has "market dominance" and there is no alternate means of transporting the product. If the shipper can prove excessive rail rates and no alternative competition exists, the "revenue adequacy" is considered, and the financial position of the carrier is reviewed.

The existing Burlington Northern rail system in Central North Dakota connects to the east with rail lines in Fargo, North Dakota and Minneapolis, Minnesota. To the west, connections are made in Terry, Billings, Helena and Butte, Montana. Connections from Montana can be made to the West and Gulf Coasts.

For established movements of particular products by railroad, rates can be obtained from the carrier in the area. Specific points of origin and destination are required. Information on contract rates, however, is usually not available. These rates vary depending on whether the railroad or the shipper owns the cars, the interchanges required with other rail lines, the condition of specific sections of track and the allowable speed thereon, the state of congestion at any terminals involved, etc. Thus, specific estimates for a contract movement are complex and difficult to calculate, and are not freely provided by the railroads.

In general, railroad tariffs per ton-mile vary greatly for short hauls, and decrease significantly (perhaps by a factor of three) as the length of haul increases to the range of about 500 to 1,000 miles. Beyond 1,000 miles the rate per ton-mile usually remains fairly constant.

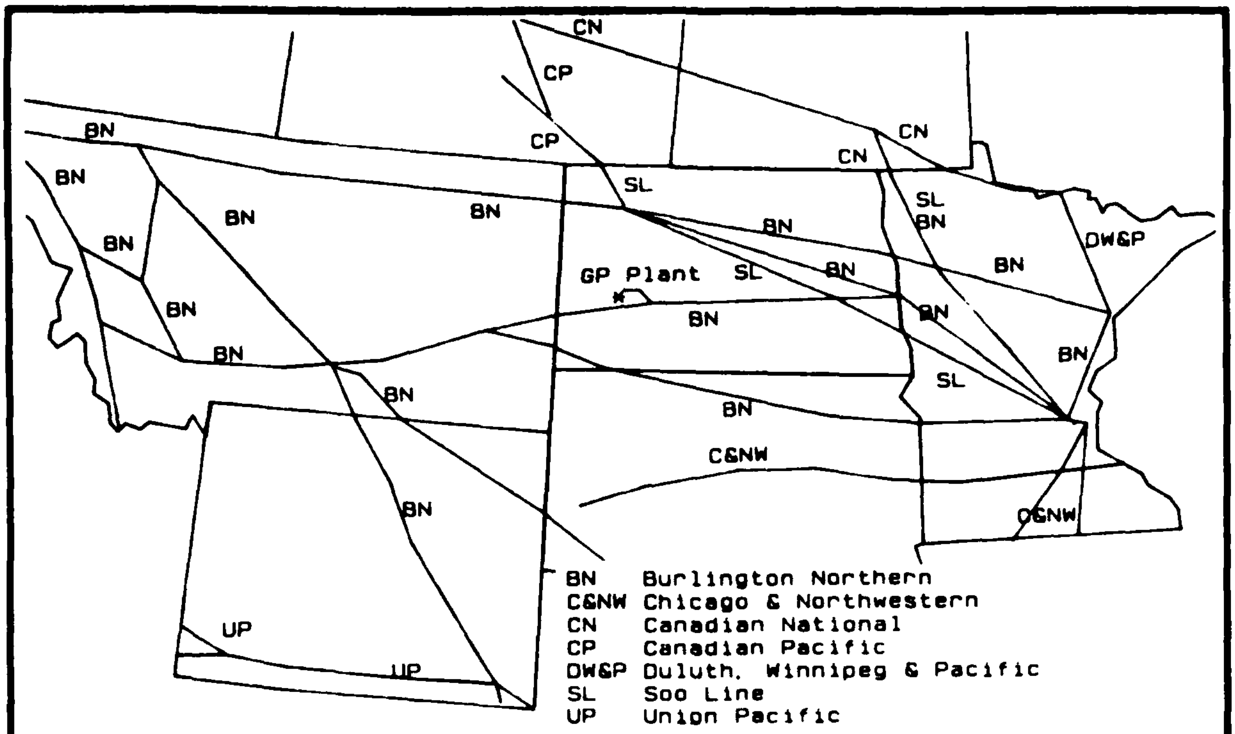


FIGURE 44

MAJOR RAILROADS IN GREAT PLAINS REGION

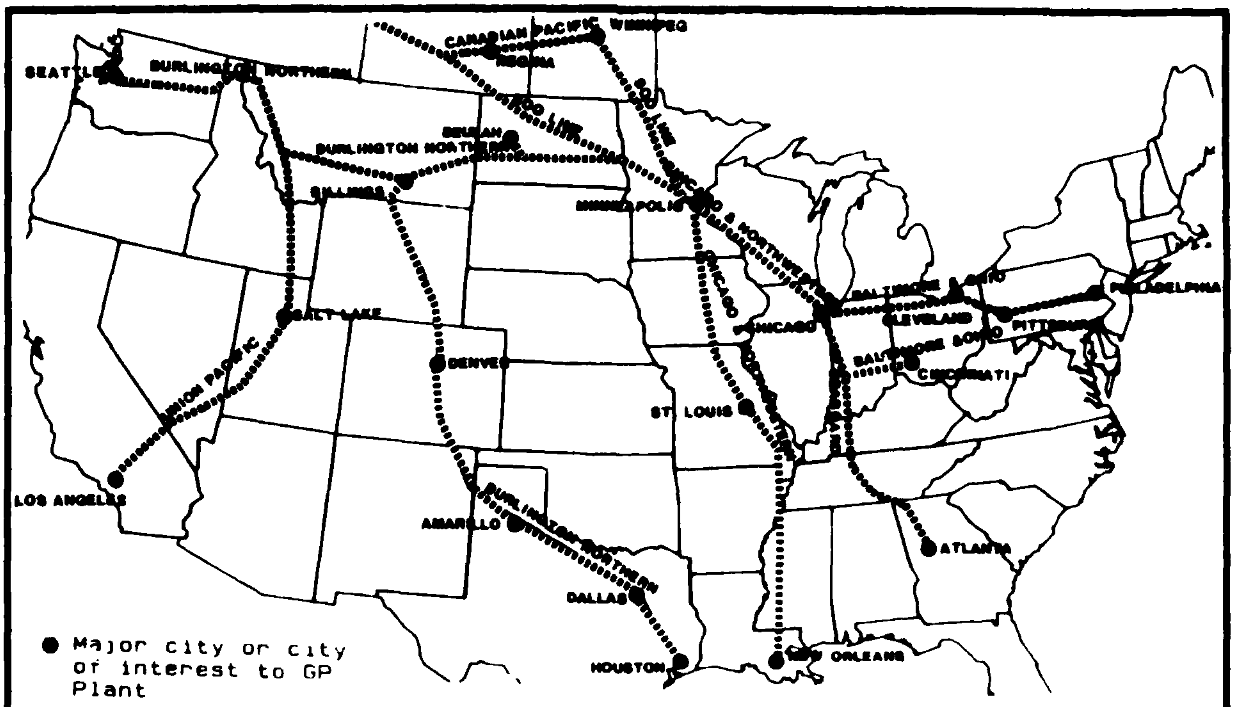


FIGURE 45

MAJOR RAILROAD ROUTES FOR GREAT PLAINS PRODUCTS

The Burlington Northern provided a current quote for products transport based on Rule 35. Their rate for Beulah, North Dakota to Minneapolis, Minnesota is $3 per hundred-weight or about $10.50 per barrel. These rates would clearly be uneconomical. BN was asked to supply an estimate of rates which could be provided under long term contract. Although the contract rates they were willing to suggest on a casual quote are likely to be somewhat different than could be negotiated in an actual situation, these rates are probably within 20 percent of a realistic value. Estimated rates for shipment to key cities are shown in Table 60. Using these rates as a basis, and applying the same ton-mile rate as a function of distance, the costs for moving liquid products to various major cities in the United States are given in Table 61.

These rates are for shipper-owned cars. Thus, total costs must include an added amount for car ownership or leasing. Ownership or leasing from third parties is generally cheaper than using railroad-owned cars. In the latter case, charges may be on the order of $0.60 per mile for a 100-ton car, or 0.6 cents per ton-mile.

Rates will also vary with the density of the product. The rates used in Table 61 assume that 190,000 pounds can be shipped in a standard 23,000 gallon tank car. If a light liquid is shipped, so that only 140,000 pounds can be loaded per car, rates would be 20 percent higher.

The railroads have demonstrated an extreme sensitivity to the presence or absence of competitive modes of transportation. In the absence of shipping alternatives, "captive shippers" have been forced to accept large rate increases since deregulation. Only the presence of competition, either from other railroads or other modes of transport, provides an effective bargaining tool. This was illustrated clearly when the railroads substantially cut the price for moving Powder River Basin coal to Arkansas and drove the ETSI coal slurry pipeline out of business. Shipment of liquid products from Great Plains would be captive to the Burlington Northern. The closest pipeline is the Amoco pipeline that runs east to Minneapolis. The pipeline, of course, would accept only fully refined products compatible with the other products being shipped in the line.

TABLE 60

KEY ESTIMATES OF RAIL TRANSPORT COSTS

Destination	Miles	$/BBL	Cents/ton-mile
Minneapolis/St. Paul (All BN)	500	3.86	4.4
Regina, Sask. (BN, Soo, CP)	560	4.30	4.4
New Orleans (All BN)	1800	6.60	2.1
New Orleans (BN, UP)	1800	7.92	2.5

TABLE 61

ESTIMATED COSTS FOR RAILROAD SHIPMENT OF LIQUID PRODUCTS FROM BEULAH, NORTH DAKOTA

Destination	Route Miles	Railroads	Dollars Per barrel
Calgary, Alberta	1,262	BN, CP	6.29
Chicago, IL	1,204	BN, ICG	6.00
Cincinnati, OH	1,694	BN, B&O	6.90
Cleveland, OH	1,553	BN, ICG, CR	6.80
Houston, TX	2,365	BN	6.90
Los Angeles, CA	2,293	BN, UP	8.20
Minneapolis, MN	500	BN	3.86
New Orleans, LA	2,019	BN, MP	6.33
Philadelphia, PA	2,063	BN, CR, ICG	6.47
Pittsburgh, PA	1,710	BN, CR, ICG	7.12
Regina, Saskatchewan	560	BN	4.30
St. Louis, MO	1,384	BN	5.80
Seattle, WA	1,461	BN	5.90

Railroad Key:

BN	Burlington Northern
B&O	Baltimore and Ohio
CP	Canadian Pacific
CR	Consolidated Rail
ICG	Illinois Central Gulf
MP	Missouri Pacific
UP	Union Pacific

If the total Great Plains liquid streams were shipped to a single destination, the volume would be marginally large enough to qualify for unit train treatment. A minimum of 60-80 cars at a time to a single destination would be required. With a unit train turnaround time of one week, this means that an average daily shipment of 4,000 to 5,000 barrels would be necessary.

Unit train costs are strongly influenced by whether more than one railroad is involved. When crossing from one railroad system to another, the train may be stopped, the engines and caboose disconnected, and a new set of engines and caboose hooked up to continue the journey.

TRUCK TRANSPORT

Truck transport is not competitive with railroads in moving bulk products over long distances. Truck transport offers an option for transporting liquids over relatively short distances where pipelines or railroads either do not exist or are not appropriate. Trucks could possibly be used for delivery of products to Minneapolis/St. Paul or Duluth for barge shipping down the Mississippi or across the Great Lakes. Truck transport can be cost-competitive in some situations because the only capital costs are for tractors and trailers, whereas for rail transport capital expenditures are required for the track.

One of the greatest benefits of truck transport is that small quantities of product can be directed in many different locations. The major drawback to truck transport is the limited, if not nonexistent, economy of scale. Such economies are large with pipeline transport and substantial with rail, but insignificant for truck transport.

The costs for truck transport were calculated from information provided by two trucking companies located in Minneapolis:

Company	Destination	$/Barrel	$/ton
Dahline	Minneapolis	10.32	58.98
Quickie	Minneapolis	7.73	44.20
Dahline	Duluth	10.57	60.38
Quickie	Duluth	8.96	51.20

The maximum truck size allowed in Minnesota is 80,000 pounds gross weight or about 170 barrels net. In North Dakota, double bottoms are allowed, or 120,000 to 140,000 pounds gross weight. These nine-axle units can haul about 90,000 pounds of payload or about 250 barrels of heavy oil.

On a volume tender of several truck loads per day, a negotiated contract at a lower rate would be possible. A 20 percent reduction of the lowest rate given would result in $6.20 per barrel to Minneapolis. This is less than the existing tariff under Rule 35 quoted by the railroad, but considerably higher than the $3.86 per barrel which could probably be obtained through a negotiated contract with the railroad.

For shipments within North Dakota, where double trailer rigs can be used, trucking costs could be competitive with rail rates, with both in the range of $0.01 per barrel per mile.

BARGES

River transport of bulk liquid products is accomplished primarily by towboats pushing rafts of barges. The towboats can range in size from less than 1,000 horsepower up to 10,500 horsepower. Larger towboat designs in the future are unlikely due to limited channel depths and lock sizes. The average power rating for most towboats on United States waterways is about 5,000 horsepower.

There has been little standardization in the sizes of barges, except that due to the size of existing locks on the rivers. The size and number of barges used depends on the size of the locks which will be traversed and the width and depth of the river. A list of typical barge sizes and their capacity is given below:

Length (ft)	Width (ft)	Draft (ft)	Capacity (Barrels)
175	26	9	7,000
195	35	9	10,000
290	54	9	23,000

Actual towing operations involve lashing a flotilla of barges together to form a single unit. Average tow speeds are on the order of five miles per hour. A towboat may push a single barge or as many as 45 barges at a time. When passing through large lock systems, barge groups of four-wide and three-long or four-long may be used depending on the size of the locks and the size of the barge. Smaller locks may handle only one or two barges at a time. Integrated tows provide an efficient method of transporting large tonnages over long distances.

The size, shape, and capacity of an integrated barge tow is greatly affected by the physical dimensions of the waterway and the construction of the lock systems. Figure 46 shows navigable rivers accessible to Great Plains products, once transported to Minneapolis or Duluth.

Lock chambers of proper size are extremely important to the overall economics of a barge operation. If the tow must pass through small locks, then breakup of the tows will be necessary. Breakup and reassembly of the barges, together with tow lockage operations, can add substantial charges to the total transportation costs. It is important that tows move smoothly in and out of locks. Traffic surges and delays in and around locks can produce the same types of problems as are encountered on highways at peak usage times.

The movement between Minneapolis and New Orleans using dedicated boats/barges, totals 25-30 days round-trip, assuming one day at the origin for loading and one day at the destination to unload. Movement to Houston or Corpus Christi uses the Port Allen cut-off from Baton Rouge to Morgan City, Louisiana, and then westward on the Intracoastal Waterway. The Houston destination adds 8.5 days to the round trip transit time, and Corpus Christi adds 13.5 days.

As with unit trains, operating costs make up a large percentage of the total costs associated with a tow. Because of this, future barge rates are expected to rise approximately parallel to the general rate of inflation. Many escala-

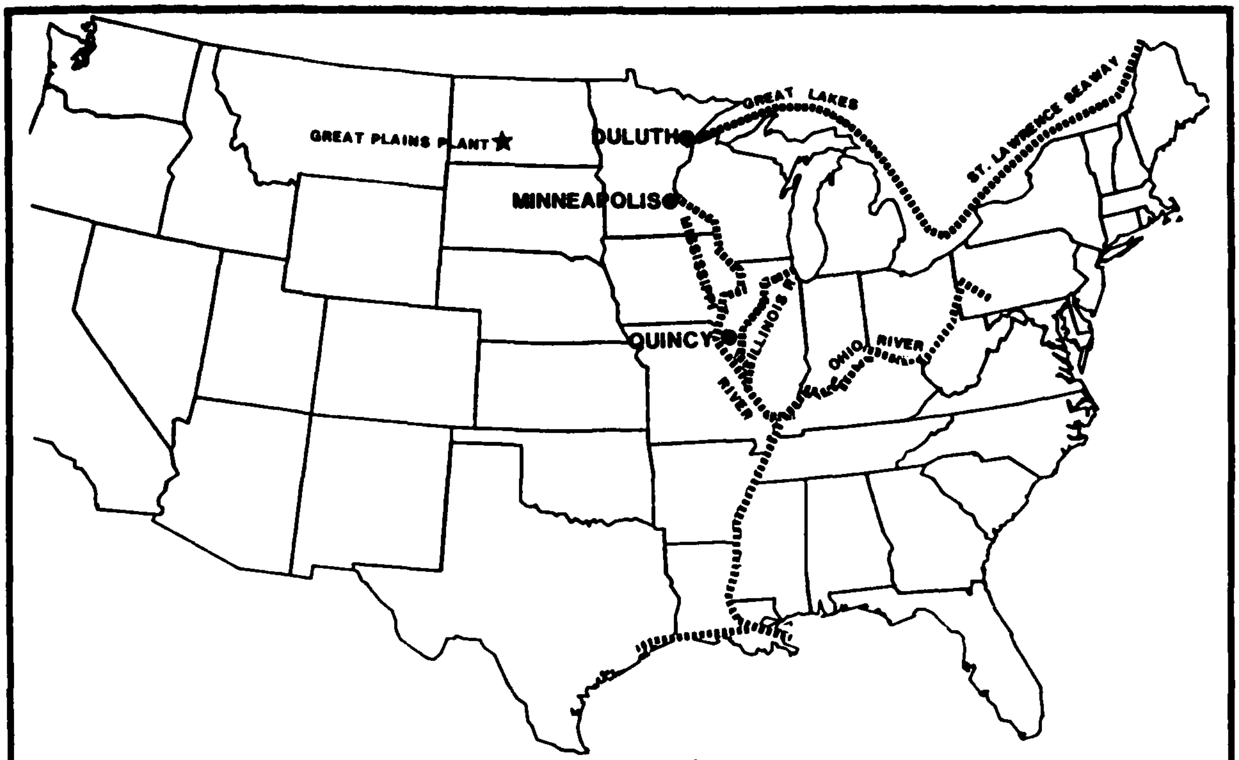


FIGURE 46

INLAND WATERWAY TRANSPORTATION SYSTEM

cost of wages, fuel, and operating supplies, as reported in the Wholesale Price Index. If loading times are extended due to crowded docks or slow pumps, a waiting charge is assessed, at a typical rate of $185 per hour.

The barge industry for the most part is unregulated. Each operator can set his own rate depending on his particular situation. For instance, if a back-haul load is available for one operator and not another, the rates quoted may be vastly different. Rates not only vary widely, but can change rapidly. Contacts in the barge industry currently consider prices to be depressed and expect this to continue until the overabundance of equipment on the rivers is diminished in two to three years.

In order to reach the waterway system, products could be shipped by railroad to Minneapolis or Duluth and then transferred to barges. Price quotes for a typical four piece tow from Minnesota to New Orleans (65,000) barrels are $3.00 per barrel if no heating is necessary. Ingram Barge Company has the facilities to load directly from rail cars to the barge at Minneapolis, so no storage would be necessary. If large tows can be put together, the price could drop to $2.00 per barrel.

Using barges as a means of transportation from Minneapolis is limited to a shipping season of April to November due to ice on the river. The city farthest north on the Mississippi that is typically ice-free year round is Quincy, Illinois, about mid-way up the state. Similarly, shipment from Duluth on the Great Lakes is limited to the ice-free season. An alternate route to the Great Lakes is possible from Minneapolis down the Mississippi to just above St. Louis, then up the Illinois River to Joliet where the Chicago ship the Great Lakes is possible from Minneapolis down the Mississippi to just above St. Louis, then up the Illinois River to Joliet where the Chicago ship canal connects to the Great Lakes. Some ice problems can be avoided by spotting with smaller barges from Minneapolis to St. Louis, but this increases costs significantly.

Major cities in the East are reached via the Ohio River system.

NETBACK PRICES

MARKET PRICES

In order to carry out economic evaluations for the various product possibilities which exist, it was necessary to determine market prices for each of the products.

Because of great changes in the prices for many products over the last two or three years, there is considerable uncertainty with regard to the prices which would exist at the time any by-products actually reach the market. Nevertheless, it was assumed that, in most cases, the most recent prices available would be the most valid for establishing an economic base case. Wherever possible, early 1987 prices were used.

Sources of price information are varied. Petroleum products are summarized and averaged on a regional basis by the Department of Energy's Petroleum Marketing Monthly. Current quotes for specific products in specific locations are available from publications such as Platts Oilgram Price Report.

For chemical products, the most comprehensive and regular source of price listings is the Chemical Marketing Report (CMR). Sporadic price information on specific products appears in publications such as Chemical Week. A major problem with prices quoted in the CMR is that they are often posted prices or list prices, which may be at significant variance from actual transactions taking place in the market place. The only way to obtain current information on actual transactions is by direct contact with buyers and sellers. Although dozens of phone calls were made during the course of this study, there were too many different products involved to be able to construct a complete pricing picture for every product. Also, many companies, for competitive reasons, are unwilling to share price information.

Direct contacts were used as a check against prices in the CMR. If CMR prices were found to correspond approximately with prices obtained by direct contact, then the CMR prices were assumed to be valid and were used. If a significant discrepancy showed up, then further effort was devoted to direct contacts in order to assess actual market prices. An adjustment to the CMR price was then made on the basis of the best information available.

Even direct contacts may not be fruitful in cases where there are few transactions taking place, and where products are purchased on long-term contracts or on once-a-year tenders.

A major difficulty arises when products are sold in various grades, usually as a function of purity, at significantly different price levels. It is tempting, but unrealistic, to use the highest prices reported. Price differences between grades must be attributed to the cost of refining or upgrading the product from one grade to another. For the purposes of a first-stage economic analysis, it should be assumed that these costs equal the price differences. Although the prices used in this analysis are conservative in the above aspect, they are undoubtedly optimistic in many cases simply because the processes and costs required to upgrade the Great Plains liquids to a particular specification are unknown. If the product is one which has to be modified to meet a number of different buyer specifications, the costs will be even more.

In summary this study uses the most current (early 1987) price information available to construct an economic base case for each product slate which is of interest. These prices are usually for the lowest-value grade found in commerce. Although this assumption seems safely conservative, it must be emphasized that it may be necessary to accept even lower prices until product performance has been established.

TRANSPORTATION

For products which could be sold in different parts of the country, transportation costs will ultimately define the market locations in which the Great Plains products will be most competitive. One approach to the market analysis would have been to simply compute the cost of transportation to the nearest potential buyer. However, there may be many reasons why that particular buyer would not end up purchasing all, or even any, of the Great Plains products. An average transportation cost to a region with potential demand several times the Great Plains output would be a more conservative assumption.

Comparison of several different transportation routes by rail and barge showed roughly comparable costs. All-rail to the Gulf Coast was comparable to rail to Minneapolis and then barge down the Mississippi. Both were comparable to rail to Duluth and barge through the Great Lakes. All-rail to Pennsylvania was comparable to a combination of rail and barge up the Ohio River. The first few hundred miles of product shipment are by far the most expensive, on a cents-per-ton-mile basis. Transportation costs per mile are relatively low after the first 1,000 miles. The isolation of the Great Plains plant means that most markets are over a thousand miles away, and therefore transportation costs to different markets are roughly of the same order of magnitude. An estimated transportation cost of $6 per barrel was found to cover an amazingly large number of cases.

NETBACK PRICES

Subtracting transportation costs from market prices yields the netback value of products at the Great Plains plant gate. Calculated netback values used in the economic analysis are listed in Table 62.

TABLE 62

1987 PRODUCT NETBACK PRICES TO GREAT PLAINS PLANT

(Dollars Per Pound)

Benzene	0.157
Carbon Black Feedstock	0.029
Cresols, Cresylic Acid, Refined Cresylics	0.383
o-Cresol	0.503
m,p-Cresol	0.551
Creosote	0.090
Gasoline	0.081
Lignite Tar	0.108
Methane	0.343
Naphthalene	0.143
Phenol	0.213
Pitch	0.108
Raffinate	0.060
Rubber Processing Oil	0.053
Solvent Oil	0.108
Toluene	0.125
Xylene	0.160
Xylenols	0.503

PROCESSING OPTIONS

REFINERY FEEDSTOCK

Examination of the hydrotreating capabilities of the regional refineries suggests that none would be able to process Great Plains tar oil as a crude feedstock. However, a new heavy oil upgrader under construction in Regina, Saskatchewan would possibly be able to do so. The upgrader will have a capacity of 50,000 barrels per day based on the Unicracking technology provided by Unocal Corporation.

The Unicracking process is illustrated in Figure 47. Feed is combined with hot hydrogen-rich recycle gas, contacted with a hydrotreating catalyst for partial desulfurization and denitrogenation, and then contacted with hydrocracking catalyst. Unicracking catalysts for a specific unit are selected for optimum attainment of processing objectives, and are based on molecular-sieve containing supports. All of the catalysts have very long operating cycles and are readily regenerated. Product from the hydrocracking reactor is condensed, separated from hydrogen-rich recycle gas and fractionated into desired products. Unconverted oil is recycled to the hydrocracking catalyst. Sixty one Unicrackers have been licensed to date.

The Great Plains tar oil stream would amount to only about five percent of the Unicracker's capacity, and thus could possibly be blended into the feedstream.

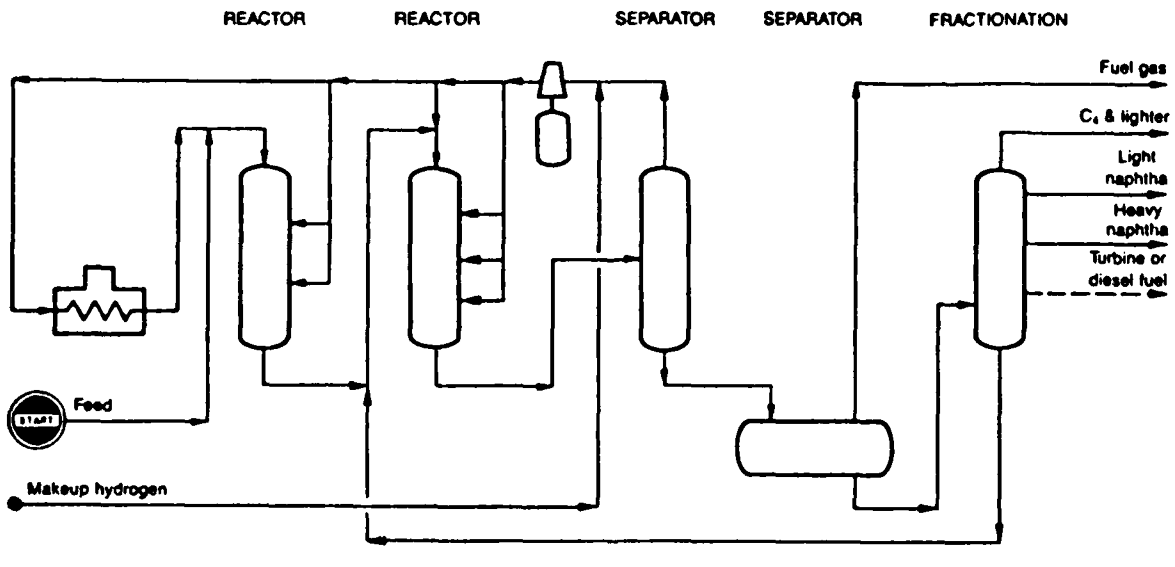


FIGURE 47

UNICRACKING PROCESS

DISTILLATION

Coal tar distillation was once a widespread industry in the United States, producing a wide spectrum of products. Today it has shrunk to the point that the few refineries left operating are for the most part only splitting the tar to make a creosote product and a pitch product. A multiproduct tar oil refining facility at the Great Plains plant might resemble the older operations at the coal tar refineries.

The warning that low temperature tars are entirely different materials than coke oven tars applies to the basic process of distillation as well as to any other processing unit. Established processing techniques for coke oven tars may not be applicable to the Great Plains materials. There are no large tar distilleries in the United States operating on a similar feedstream, although there are installations in Europe.

Two major differences of importance to distillation are the instability of the Great Plains tar oil, and the large amount of tar acids which it contains. The University of North Dakota Energy Research Center reports that it is impossible to perform an ASTM D-86 distillation on the tar oil because it starts decomposing before the last 10-30 percent distills over. Decomposition and polymerization is indicated by smoking. The temperature at which smoking begins depends on the heating rate used.

The laboratory results indicate that to distill material in the 260 to 300 °C range, vacuum distillation would be required to avoid smoking. It might be just barely possible to fractionate off the cresylic acids before this happens.

It is not clear what the effect of smoking would be on distillation. The actual composition of the bottoms does not appear to change significantly, at least in a short period of time.

Because of the instability problem, a tar oil distillation system would have to be a combination atmospheric and vacuum unit rather than a straight atmospheric still. Coal tar stills have been designed in the same way, although for different reasons. These reasons include the much heavier constituency of coal tar and the need to use vacuum to increase the recovery of distillate materials. A combination atmospheric and vacuum tar distillation system is illustrated in Figure 48, showing the complex heat exchange arrangements which may be used to recover the process heat. In this Teerverwertung-Koppers design, the crude tar is pumped through five heat exchangers, in which it extracts heat from all the oil products and the pitch, and is pumped into the dehydration tower. The light oil and steam vapors from the top of the dehydrator are cooled, condensed, and separated, and some of the light oil passed back as reflux. The dehydrated tar is pumped through a heating coil in the tube furnace and injected into the atmospheric pressure fractionating stage, which consists of two fractionating columns and a splitting column. The products include residual light oils and water, taken as overheads from the first column and passed back to the dehydrator, phenolic oil as a side stream from the first column, naphthalene oil as the overhead from the second column, and wash oil as the base product from the second column.

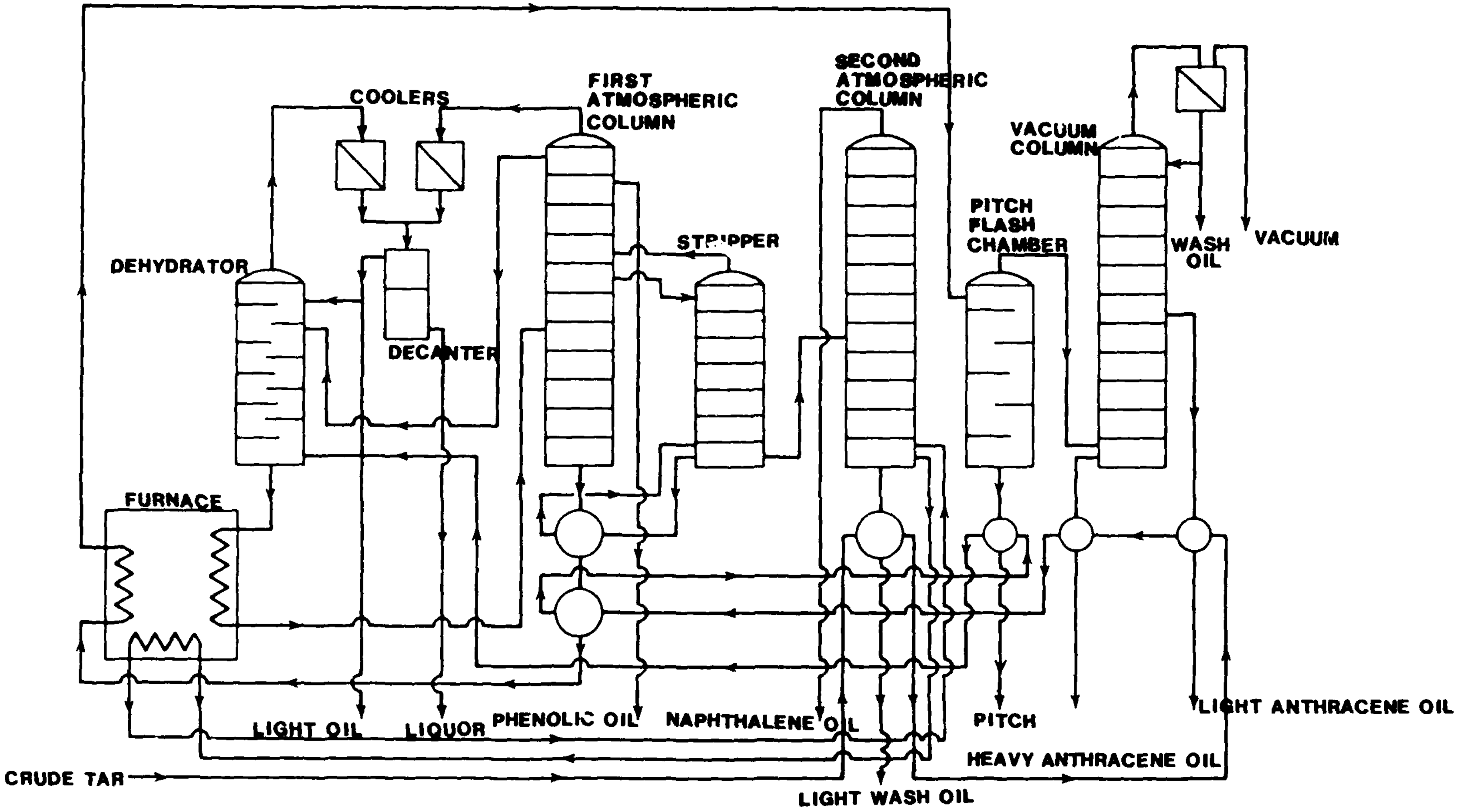


FIGURE 48

ATMOSPHERE AND VACUUM TAR DISTILLATION SYSTEM

The topped tar from the base of the first column is heated in a separate heating coil in the furnace and injected into the pitch flash chamber that, like the final fractionating column, is maintained under a vacuum of 100 mm Hg. The residual oil vapors separated from the pitch are divided into a heavy wash oil, and a light and heavy anthracene oil in the vacuum column.

The detail of the preceding design would not apply directly to the Great Plains tar oil because of its much lower content of high boiling material.

The high content of tar acids found in the Great Plains tar oil stream may affect distillation economics because of their corrosive effect. In most tar distillation systems, the crude tar is doped with a small amount of aqueous alkali to neutralize ammonium salts and thus prevent corrosion. If this is not effective, more expensive materials of construction would have to be used to avoid corrosion problems.

PITCH

Although there are references in the literature to thermal treatment of low temperature tars to make a binder pitch, it is not known whether the Great Plains low temperature lignite pitch can be processed to yield anode grade pitch. In making binder pitch from coke oven tars, the crude tar is distilled to a medium-soft pitch residue and then hardened by heating for 6-10 hours at 385-400 °C. This treatment increases the toluene-insoluble content with only a slight increase in the quinoline-insoluble material.

The coke yield from coal tar pitch has been increased by adding an air blowing or catalytic oxidation step before coking. If an analogous process could be devised for low temperature lignite tar without increasing the quinoline insolubles, perhaps a suitable binder could be produced. Domtar Inc. has reported (1984) success with a new filtration process for removing quinoline insolubles. Quinoline insolubles consist of various resins (true QI) plus particles of dirt, coke, crystals, etc. which agglomerate to form lumps in the pitch. These lumps are detrimental to the flow and impregnating properties of pitch when mixed with coke to form electrode paste. It is conceivable that the Domtar process could be coupled to a pitch modification step.

Pitch once was stored in solid form at the tar distillery in open bays, from which it was removed by small explosive charges, and then loaded by mechanical shovel. Now, pitch is stored in tanks heated by steam or circulating hot-oil coils and transported in liquid form in insulated rail or road tankers. When transport as a hot liquid is not feasible because of distance or quantity or need for long-term storage, the pitch is converted into a dust-free particulate form (short rods termed pencils, pastilles, or flakes).

Some plants employ cooled-belt flakers. Molten pitch flows from a tank over a weir to give a flat thin sheet on a flexible steel belt, which is cooled from below by water sprays. At the end of the belt, the solid pitch is broken up by rotating tines.

Direct water cooling is also employed in a pitch-pencilling plant. Molten pitch is pumped through nozzles at a rate and pressure to give a series of almost horizontal jets. These jets project a short distance into horizontal tubes through which a cocurrent streamline flow of cooling water is maintained. The stream of pitch solidifies into solid rods about 10-20 mm thick which break up into short lengths as they are forced around a bend in the tube.

In another type of pitch-pencilling plant, circular streams of molten pitch from numerous nozzles fall by gravity into a tank containing water where the pitch hardens into solid rods.

NAPHTHALENE

Naphthalene is a principal component of coke oven tars and can be concentrated to a reasonably high level by primary distillation. A naphthalene oil can be produced which contains 60-65% naphthalene. In an older procedure, the naphthalene oil is simply cooled in pans, and the naphthalene crystallizes out. The crude crystals are centrifuged and then pressed in a mechanical press. The lower melting crystals which are expressed as a liquid are 95.5 percent pure and are satisfactory for producing phthalic anhydride.

With the Lurgi gasifier tar oils, it will be necessary to remove the tar acids before naphthalene can be crystallized.

A variety of processes have been developed for upgrading crude naphthalene to a higher purity grade. In one approach the crude crystals are melted and then allowed to re-solidify in a tank. The tank is then warmed to just below the desired melting point, and any oil formed is drained away.

In another approach, crude naphthalene crystals are melted, charged to tall cylindrical tanks, and partially cooled. Mother liquor is drained off, and the crystals washed with methanol. Brodie crystallizers developed to separate o- and p-dichlorobenzene, have also been used for naphthalene refining.

CRESYLIC ACID

Because phenol, the cresols and the xylenols all boil over a narrow temperature range, a crude tar acid cut can be obtained from the tar oil by distillation. This cut will also contain neutral oils and tar bases. Because these other materials boil in the same range, the tar acids cannot be purified by distillation. Three different methods of separation which have been practiced commercially are described in the following.

Caustic Extraction

The tar acids can be separated from the neutral oil and tar bases by first extracting the acids with caustic, then "springing" them from the caustic by neutralization with carbon dioxide.

Refined cresylic acid may then be produced by simple distillation. Phenol and o-cresol may be separated relatively easily, but the other cresol and xylenol isomers have boiling points too close together to separate easily by distillation alone.

In a typical procedure, tar oils are mixed with a slight excess of 10% aqueous caustic soda in stirred vessels or continuous extraction columns. The extraction is carried out at ambient temperature or just above the crystallizing point of the oil. It is best carried out in two stages, using 90 percent of the alkali to contact the fresh oil and the remainder to complete the removal of the phenols. The crude phenate or cresylate solution is separated, and contains some neutral and basic material which must be removed by extracting with phenol-free light oil and/or treating with live steam.

The purified sodium phenate solution is then decomposed by passing it down packed towers at 80-85 °C countercurrent to a gas containing 25-30% carbon dioxide. This operation is called springing. Since the rate of CO_2 absorption depends on the CO_2 partial pressure, a richer gas reduces the number and size of the springing towers required. Favorable conditions would be present at the Great Plains plant because of the availability of CO_2 vent gas. An upper layer of crude wet tar acids and a lower layer of sodium carbonate solution is obtained. The crude wet tar acids contain ca 20-25% sodium carbonate solution and, to reduce their moisture content to ca 10 percent, the crude wet tar acids are passed down an after-carbonation tower countercurrent to a stream of the CO_2-containing gas. Separation of the layers yields crude tar acids containing ca 10% liquor and a solution of sodium carbonate and bicarbonate.

Caustic soda can be recovered from the carbonate/bicarbonate solution by treating with an excess of hard-burned quicklime in a stirred reactor. Disposal of the washed lime mud poses a problem.

In the next stage in the recovery and refining of tar acids, water and pitch are removed from the crude tar acids in a continuous-vacuum still. The aqueous phenol overhead distillate is recycled, the stream of once-run tar acids is refined, and the phenolic pitch bottoms are burned.

The once-run tar acids are fractionated in three continuous-vacuum stills containing 40-50 bubble trays and operating at reflux ratios between 15 and 20:1. The overhead product from the first column is 90-95% phenol; from the second, 90% o-cresol; and from the third, a 40/60 m,p-cresol mixture. Further fractionation is required to give the pure products.

At other refineries, only two continuous stills in series are used, but these are of 80-100 plate efficiency and yield pure grades of phenol and o-cresol and a base mixture of cresols, xylenols, and higher boiling tar acids. The latter are fractionated batch-wise to various salable grades of cresylic acids.

A flow sheet of a typical tar acid extraction and refining plant according to the above description is shown in Figure 49.

Phenoraffin Extraction

The Phenoraffin process developed by Lurgi uses physical solvent extraction rather than caustic reaction to extract phenols from tar oils. A flow sheet is given in Figure 50.

The phenolic oil stream is charged to the middle of a multi-stage extractor. Aqueous sodium phenolate solution is admitted to the one side of the extractor and light naphtha or toluene to the other side. The aqueous phenolate solution picks up the phenols, and the light naphtha absorbs the neutral oils.

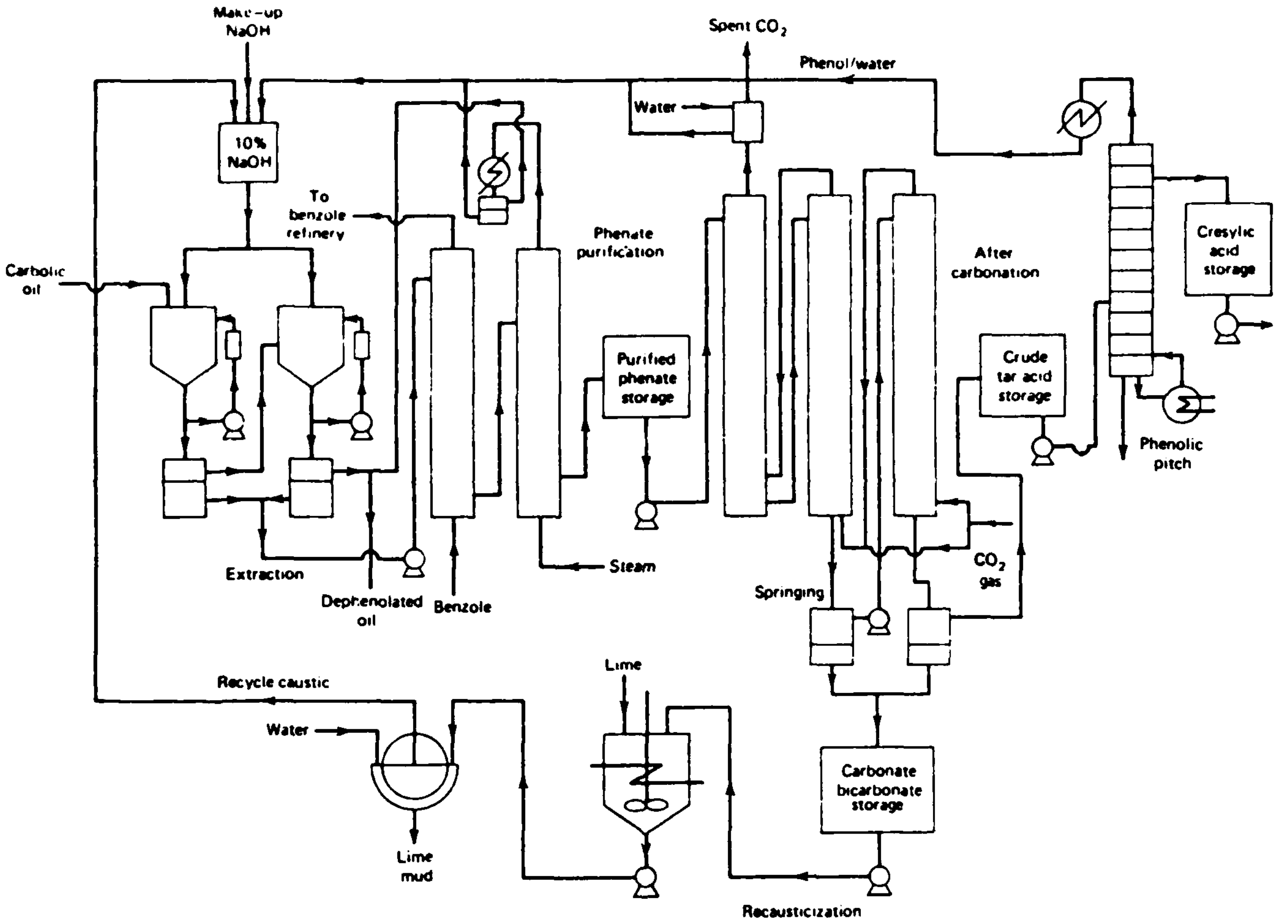


FIGURE 49

TAR ACIDS EXTRACTION WITH CAUSTIC

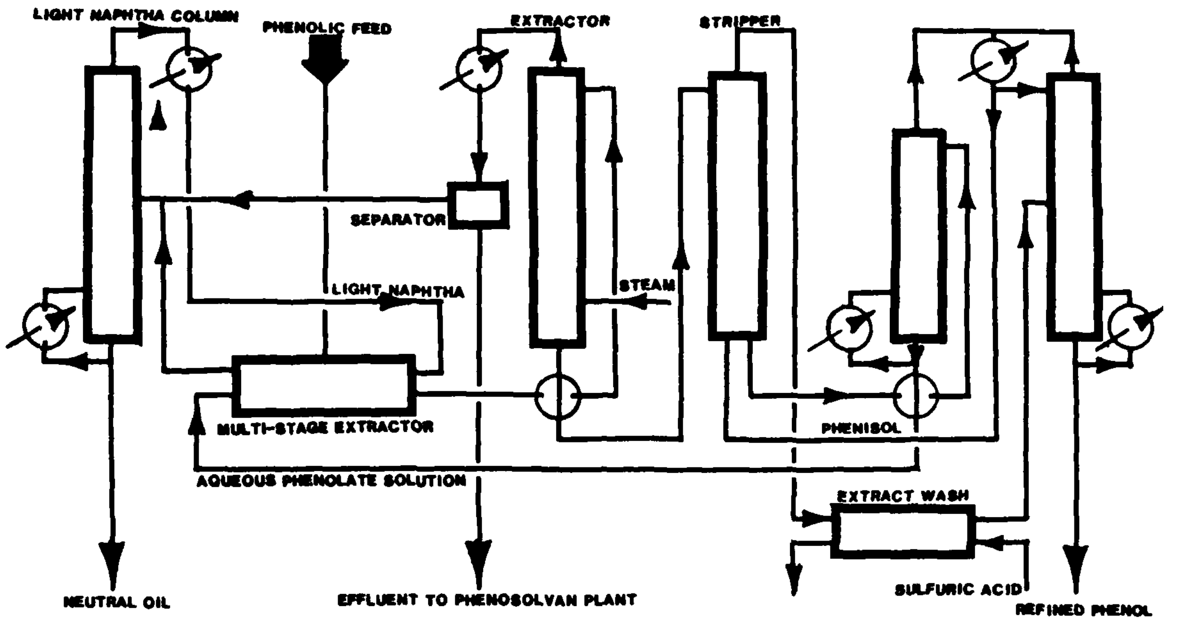


FIGURE 50

PHENORAFFIN EXTRACTION PROCESS

Light naphtha and neutral oils are separated by distillation, the light naphtha being returned to the extractor.

The phenol-laden phenolate solution contains a small amount of naphtha and neutral oil which are removed in a stripper. The phenol/phenolate solution leaving the stripper bottom is treated with isopropyl ether (IPE) in an extractor whereby the phenol dissolves in the IPE. The remaining phenolate solution is freed of dissolved IPE in a stripper before it is returned to the multi-stage extractor.

The phenol/IPE extract after removal of pyridine by sulphuric acid wash, is distilled into IPE and refined phenols.

Methanol/Hexane Extraction

Pitt-Consol Chemical Company operated a cresylic acid extraction plant at Newark, New Jersey which produced about 35 to 50 million pounds of cresylic acids per year. It used a dual-solvent system similar to the Phenoraffin approach, and an agitated Schiebel-type extractor. The solvents were methanol and hexane. Both coal tar and petroleum caustic washes were used as feedstock.

This same system was used in a pilot plant extraction facility for the lignite tars produced by the Parry carbonizer which was built at Rockdale, Texas. The same approach was planned to be used for the proposed low-temperature tar refinery at Cresap, West Virginia. It has also been used by Merichem, the largest United States producer of cresylic acids.

Distillation Purification

After extraction by any of the above methods, the phenols stream can be separated into phenol and individual cresol isomers and xylenols. A typical distillation scheme is shown in Figure 51.

The extracted phenols are fractionated under vacuum batchwise in one or two columns, if the capacity of the plant is small, or continuously in a series of columns, if the capacity of the plant is large.

In the first column, phenol and o-cresol are distilled overhead together with the low-boilers. This overhead product is fractionated further in a second column. The second column overhead product consists of aqueous low-boilers, the side-stream fraction is pure phenol, and the bottoms product is an o-cresol fraction which is supplied to an intermediate storage tank. The first column bottoms product consisting of m- and p-cresol and xylenol is fed to a second intermediate tank. In a third column, o-cresol, m- and p-cresol and xylenols are alternately treated batchwise, depending on the specification of the required product.

Modern cresylic acid processors have developed their own proprietary techniques both for producing isomers other than o-cresol, and for removing certain impurities to meet specific consumer needs. This processing technology is neither public knowledge nor offered for license. It would be difficult for a new producer to obtain enough processing knowledge to be able to supply specification grade products to all consumers on startup.

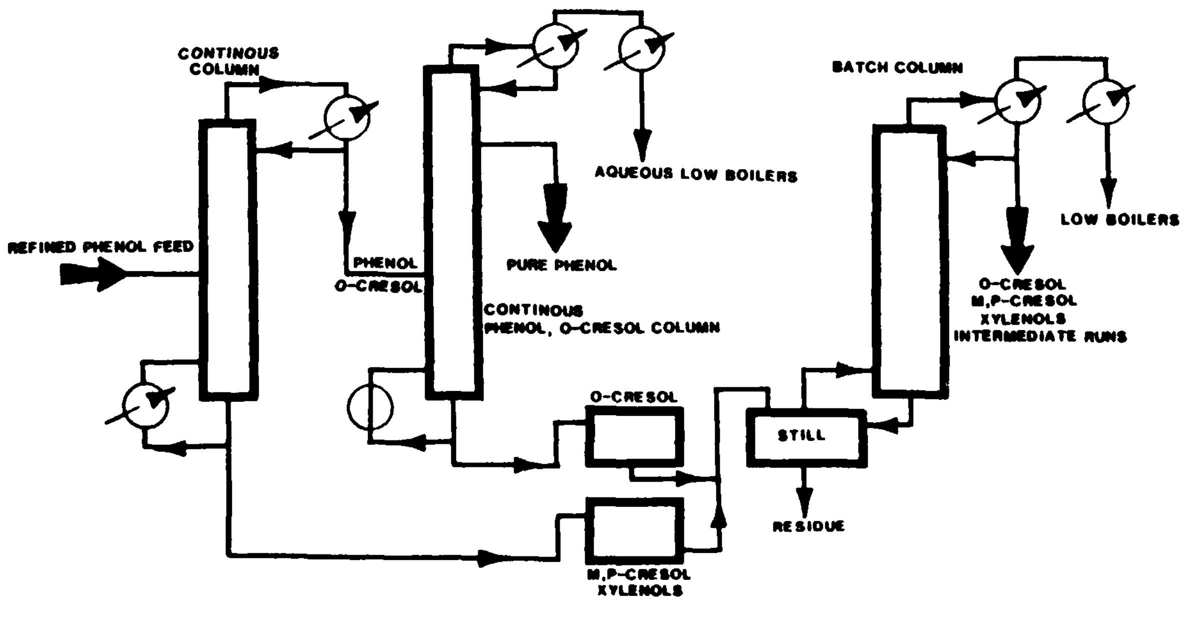


FIGURE 51

FRACTIONATION OF PHENOLS

Great Plains may have a feedstock cost advantage over other natural cresylic acid producers. In going from cresylic acid to pure cresols, however, Great Plains would have no advantage, other than economy of scale, over any other producer. Thus, if an intermediate marketing arrangement could be worked out with a producer or producers having existing surplus refining capacity, this would result in the best overall production economics. New capital investment would not be required. Merichem in Houston may have enough capacity to process all the Great Plains material by rearranging feedstocks and flows in their plant.

BENZENE

Sulfolane Extraction

Two basically different process routes are available to recover benzene from the naphtha stream. The first is solvent extraction. The process chosen for evaluation is the Sulfolane process offered by UOP, Inc. A schematic flow sheet is given in Figure 52.

The process recovers a mixture of BTX aromatic liquids. As typically applied, the sulfolane separation of the aromatics from a hydrocarbon mixture is accomplished partly by liquid-liquid extraction and partly by extractive distillation. It is distinguished both from conventional liquid-liquid extraction and from earlier commercial processes using only extractive distillation.

Fresh feed enters the extractor and flows upward, counter-current to a stream of lean solvent. As the feed flows through the extractor, aromatics are selectively dissolved in the solvent, and raffinate of very low aromatics content is withdrawn from the top of the extractor.

Rich solvent from the extractor enters the extractive stripper, in which partial stripping of hydrocarbon from the rich solvent takes place. The non-aromatic components having volatilities higher than that of benzene are essentially completely stripped from the solvent and removed in the overhead stream. This stream is returned to the extractor as reflux for recovery of aromatics.

The bottoms stream from the extractive stripper consists of solvent and aromatic components, substantially free of non-aromatics. It enters the recovery column, in which the aromatic product is separated from the solvent stream. Because of the large difference in boiling point between sulfolane and the heaviest desired aromatic product, this separation is accomplished readily. Lean solvent from the column bottom is returned to the extractor.

Raffinate from the extractor is contacted with water to remove dissolved sulfolane, and the rich water is returned to the extract recovery column as stripping steam generated via exchange with the hot circulating solvent in the water stripper reboiler. Dissolved sulfolane accumulates in the water stripper bottom and is pumped back to the recovery column.

Sulfolane has been applied to the recovery of petrochemical grade aromatics from coke oven naphthas. The naphtha stream would have to be hydrotreated to stabilize it before feeding to the sulfolane extraction unit. The UOP LT Unibon process (Figure 53) was assumed for this purpose.

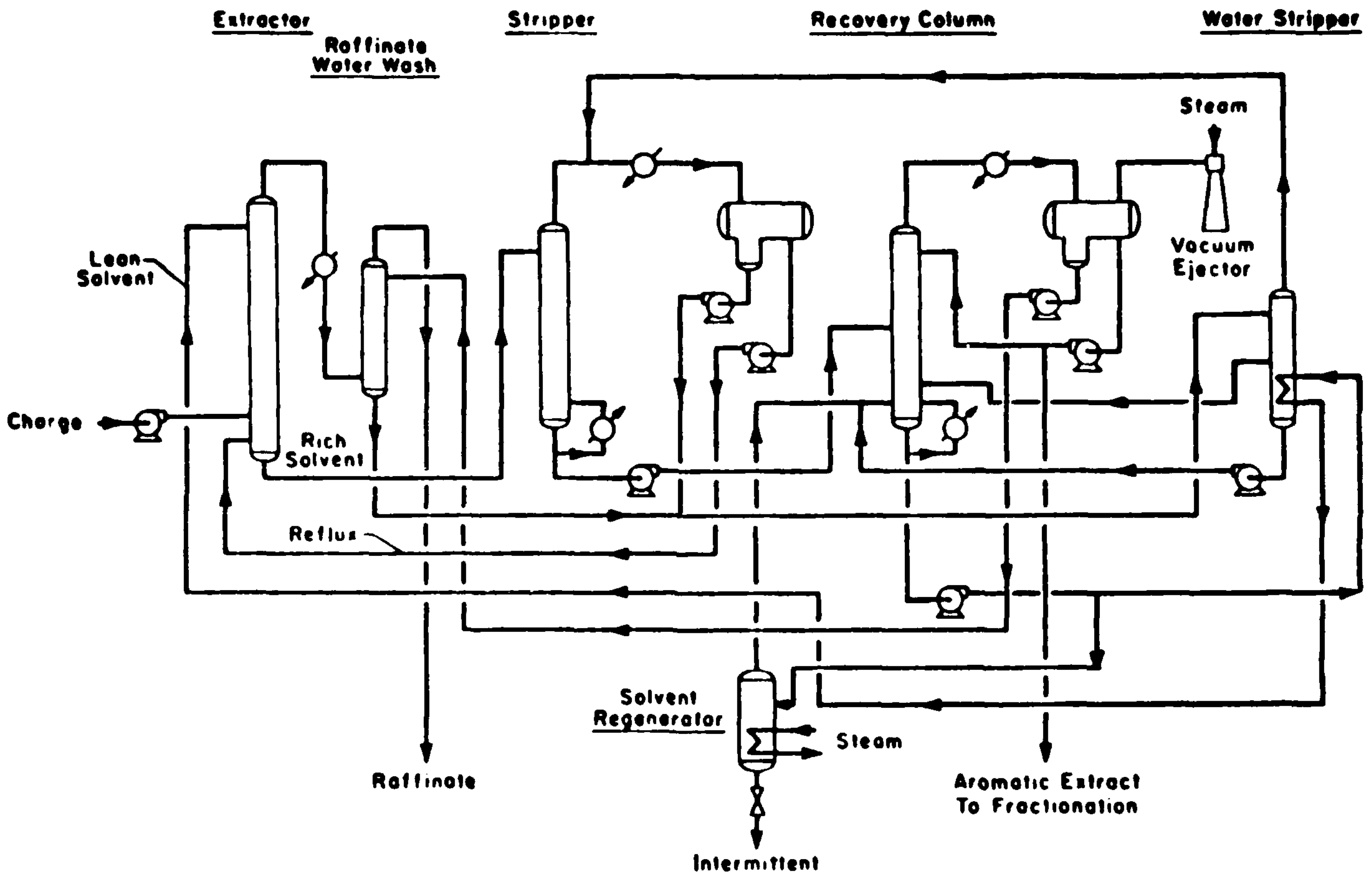


FIGURE 52

SULFOLANE EXTRACTION OF AROMATICS

The UOP LT Unibon process is a two stage hydrotreating process employing suitable catalysts to allow the selective hydrogenation of a wide range of diolefins, mono-olefins, sulfur and nitrogen contaminants, without the formation of troublesome gum, polymer and coke on heat exchangers, heater tubes, and catalyst beds. Hydrocracking of feed to light ends is minimal and is confined to those fragments created by the fracturing of the sulfur and nitrogen containing compounds.

Two LT Unibon units have been built which operate on coke oven light oils.

Hydrodealkylation

A number of commercial processes are available for the hydrodealkylation of alkyl benzenes to benzene. Both catalytic and non-catalytic processes are available. These processes are normally used to convert toluene to benzene whenever benzene is in short supply. The process selected for evaluation is the Litol process offered by Houdry (Figure 54).

The Litol process was developed for the purification of coke oven light oils. Benzene yield is significantly greater than benzene present in feed because of dealkylation of heavier aromatics to benzene, and dehydrogenation of naphthenes.

Crude light-oil, together with a hydrogen stream, is heated at above atmospheric pressure and passed over a catalyst. The effluent is cooled by heat exchange and passed through a gas/liquid separator. The light gases are recycled. The liquid is stabilized to remove hydrogen sulfide and light gases. Conventional distillation can then separate the remaining liquid into benzene, toluene and xylene. The toluene and xylene fractions may be recycled through the Litol reactors until completely converted, with a corresponding increase in benzene yield.

BENZENE + PHENOL

As an extension of the HDA thermal hydrodealkylation process to make benzene, HRI Inc. has developed the Dynaphen process to convert mixed alkylphenols in coal liquids to phenol and benzene.

The Dynaphen reactor primarily dealkylates cresylic acid molecules, although some dehydroxylation occurs as well. Dehydroxylation products (toluene and xylene), plus the unconverted alkylphenols are recycled to the Dynaphen reactor so that the major reactor products are phenol and benzene.

Figure 55 illustrates the basic flow scheme of the Dynaphen Process. The alkylphenolic feed to the process is mixed with hydrogen and sent to the Dynaphen preheater and reactor. The reactor effluent is cooled by exchange with reactor feed (and other process streams) for heat recovery, and is separated into vapor- and liquid-phase components. Some light gas is produced in this process, mostly methane and some carbon monoxide.

The liquid reactor effluent may be sent through a stabilizer and a clay tower before distillation. Benzene and phenol are recovered in two series-connected

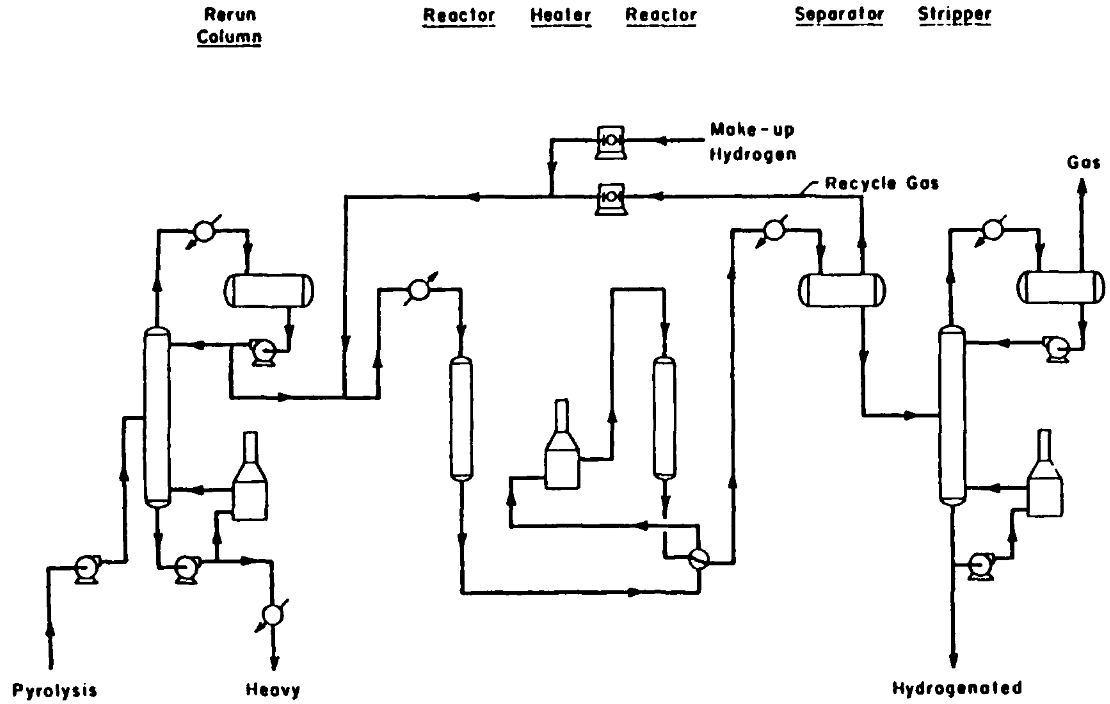


FIGURE 53

LT UNIBON HYDROTREATING PROCESS

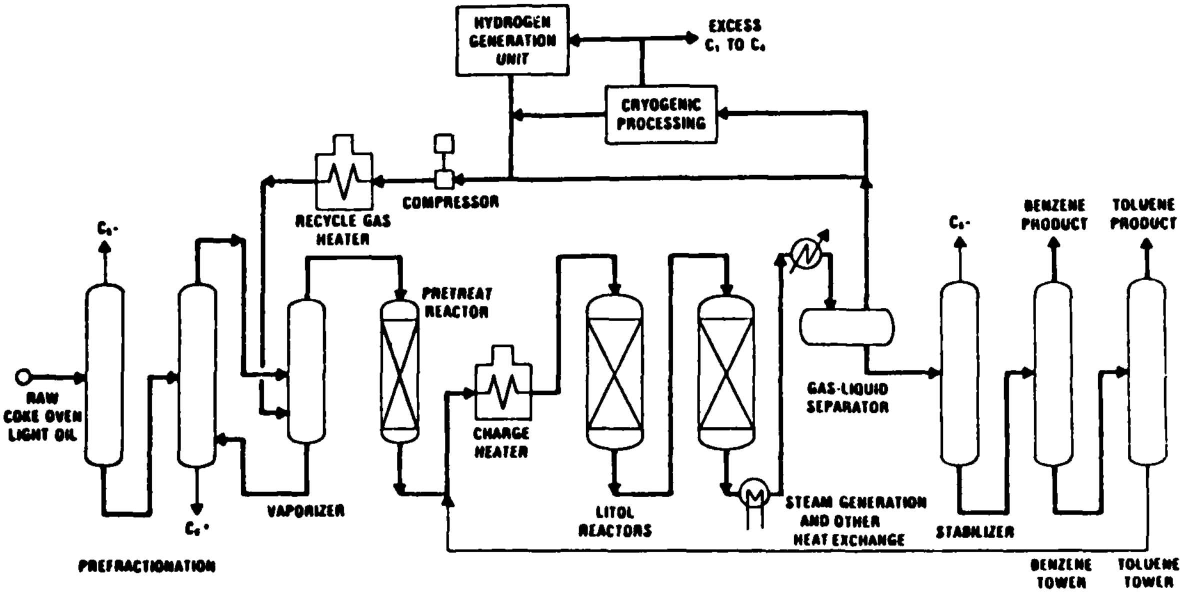


FIGURE 54

LITOL HYDRODEALKYLATION PROCESS

distillation towers. Unconverted alkylphenols are recycled to the Dynaphen reactor. Dehydroxylation by-products, primarily toluene and xylene, are also recycled, eventually producing benzene. Thus, the net products of the Dynaphen system are benzene and phenol.

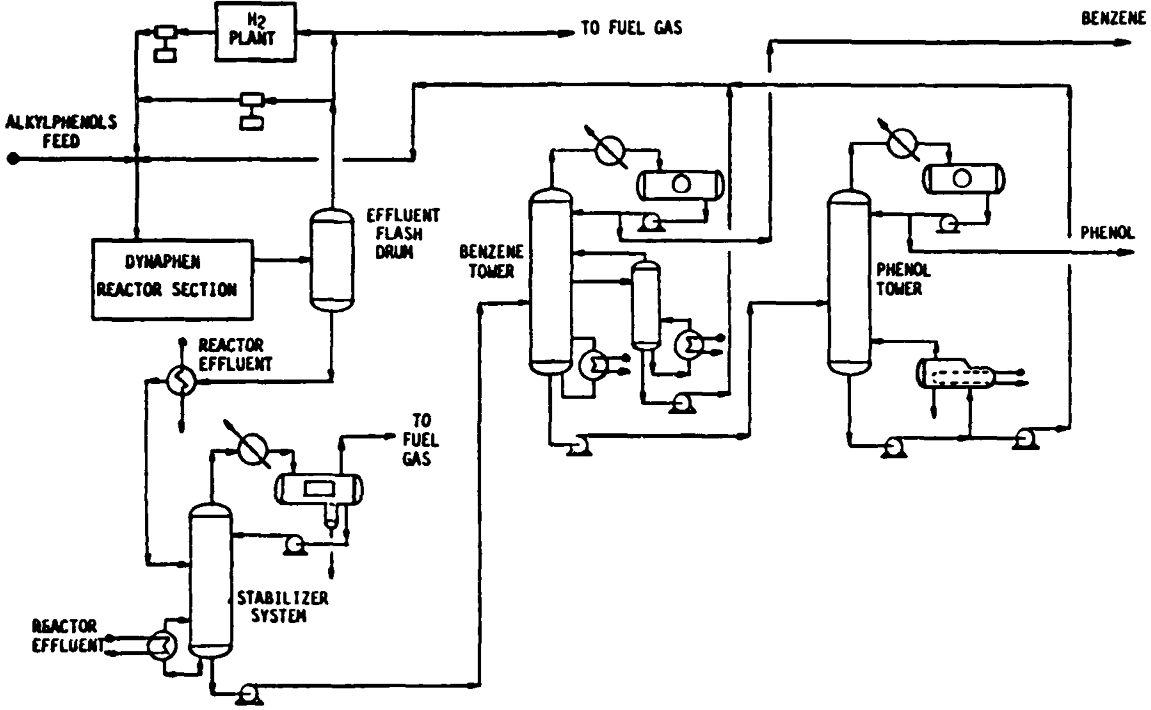


FIGURE 55

DYNAPHEN PROCESS

PROCESSING ECONOMICS

Capital and operating cost data from available sources were updated to 1986 costs and prices. A complete economic analysis was then carried out for several different product slates, process configurations, and capital cost estimates. It must be emphasized that the available cost data are far from investment-grade. The data are from preliminary feasibility studies which were not based on plants which had actually been built and operated in the recent past.

ECONOMIC PARAMETERS

Ground rules for performing the economic runs included the following:

1. Basis is 100 percent equity for capital investment.
2. Plant costs are given in 1986 dollars.
3. Construction starts in 1988 and the plant is onstream in 1990.
4. No land purchase necessary.
5. Onstream factor is assumed to be 100 percent.
6. Operating and capital costs, and product prices are assumed to escalate according to the Data Resources Inc. United States GNP deflator forecast.
7. Plant life is 20 years.
8. After calculating depreciation allowances and taxes, the year-by-year cash flows are then de-escalated to give net present values and rates of return on a constant dollar basis. This procedure properly accounts for the devaluation of depreciation deductions by inflation.
9. Federal taxes correspond to the Tax Reform Act of 1986.
10. At the time of beginning this study, the North Dakota tax structure allowed federal taxes to be deductible. This is likely to change in the future, but for this study it was necessary to assume no change.

North Dakota's tax structure contains some complex provisions for special taxes on coal conversion facilities. The "coal conversion facilities privilege tax" is imposed on the operator of a coal conversion facility for the privilege of producing electricity or other products from coal conversion plants. The coal conversion tax is in lieu of property taxes on the plant itself. For coal gasification plants, the tax amounts to 15 cents per 1,000 cubic feet of gas produced for sale, or else 2.5 percent of gross receipts, whichever is greater. The definition of gross receipts excludes any financial assistance from the federal government.

A five-year exemption from the tax may be allowed for any facilities constructed after July 1, 1985. This exemption is discretionary, and is granted in consideration of new jobs created by the facility. Privilege tax revenues are distributed 65 percent to the state and 35 percent to the county. The county may grant or deny a five-year exemption to their own portion of the tax. If an exemption is granted by the county the facility owner can then apply to the state for a similar exemption.

In this analysis, it was assumed that the new capital investment required for by-products upgrading would be a free-standing project. It would buy already-converted liquids from Great Plains and upgrade them for sale. As such, it would not be a coal conversion plant and would not be subject to the coal conversion privilege tax. Increased revenues flowing to the Great Plains plant under this arrangement might be subject to the 2.5 percent gross receipts tax. However, if the gas were being sold at current conditions, the rate of 15 cents per thousand cubic feet on the gas product would be much greater than 2.5 percent of total revenues. Therefore, there would be effectively no additional privilege tax to be paid as a result of added by-product revenues.

Although it is likely that a by-products plant would qualify for a five-year exemption from both ad valorem taxes and income taxes, such exemptions are discretionary, and this analysis did not assume that such an exemption would be available. For the purposes of this analysis, where only order-of-magnitude estimates are available for capital and operating costs, it was found that the tax effect would be small in comparison to other uncertainties.

In order to compute variable operating costs, it was necessary to assign a value to the three by-product streams coming from the plant. Because these streams can always be burned in the plant (as in current practice), they must be assigned a value equivalent to the cost of providing replacement fuels. Economic analyses were run by assigning three different values to this liquid feedstock transfer price. Liquids transfer prices of $1, $2 and $3 per million BTU were used to bracket the possible future value of these liquids as plant fuel. The maximum liquids transfer prices would be that required to purchase replacement residual fuel oil from outside sources. At early 1987 prices, this would be less than $3 per MMBTU. If it proves practical to fire the plant boilers and other systems with lignite fines, then the minimum liquids transfer price would be equivalent to the netback now received by sending the fines to the adjoining electric power plant (estimated to be about $0.58 per MMBTU). This is exclusive of the capital investment required to be able to fire lignite fines.

The other major unknown in each case, besides the transfer cost for the raw by-product streams, is the capital cost for the upgrading facilities. There are no reliable data available. No coal tar refining plants have been built for many years, and no up-to-date cost estimates were found. A number of the processes which might be used have never been demonstrated on a similar feedstock, and/or have not been built in the size range which would be necessary. This places an extremely high measure of uncertainty on the capital cost estimates. To partially account for this uncertainty, each case was run a second time, with the capital cost arbitrarily increased by 100 percent. It should be noted that it is possible that actual costs would be less than the base case. Verbal communication with ANG personnel indicates that the capital cost for a cresylic acids process could be 50 percent less than the El Paso estimates due to utilities and auxiliaries already in place and lesser factors for overhead, administration and marketing.

EL PASO PRODUCTS CASE

The first case analyzed was based on work carried by El Paso Products Company for a commercial coal gasification project in New Mexico. This was a paper study only, the plant was never built. The El Paso by-products flow sheet is shown in Figure 56. It is a total utilization scheme, converting all the liquid by-product schemes to saleable products. Flow rates have been adjusted to correspond to the quantities produced at the Great Plains plant. The product slate resulting from this configuration is given in Table 63. Prices are early 1987 prices.

Capital investment costs corresponding to Figure 56 are summarized in Table 64. Operating costs are given in Table 65.

The El Paso cost data are considered to be especially applicable because the plant was based on Lurgi gasifiers running on New Mexico subbituminous coal. The liquid by-products from such a facility would more nearly resemble the Great Plains lignite tar liquids than would liquids from coke oven tars (the liquids for which most tar refining facilities have been designed).

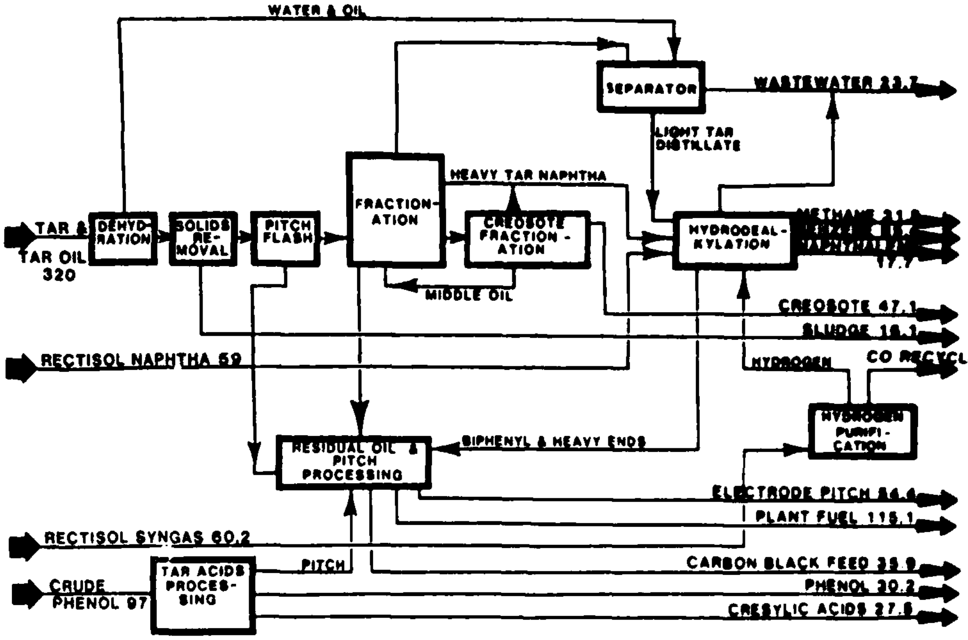
Results of the economic analysis are given in Figure 57. Discounted cash flow rate of return varied from 14.3 percent at a liquids transfer cost of $1.00 per million BTU to 2.6 percent at a transfer cost of $3.00 per million BTU. Increasing the capital investment by 100 percent dropped the rate of return by over seven percent.

MODIFIED EL PASO CASE

The El Paso processing scheme includes a hydrodealkylation unit to convert the Rectisol naphtha and tar oil naphtha to benzene and naphthalene. Co-product methane is returned to the gasification plant product stream for credit. Hydrogen for the dealkylation is obtained by cryogenic separation of a sidestream of synthesis gas from the gasification plant. This scheme was modified by changing the hydrogen generation step.

Instead of the cryogenic separation it was assumed that hydrogen would be obtained over-the-fence from a pressure-swing adsorption unit located at the gasification plant (Figure 58). A manufactured hydrogen cost of $1.70 per thousand cubic feet was provided by ANG Coal Gasification Company. This figure is based on a value of $3.00 per million BTU for the synthesis gas, and return of the carbon monoxide to the process. The product slate, capital investment, and operating costs for this case are given in Tables 66, 67 and 68, respectively.

Results of the economic analysis are plotted in Figure 59. The rate of return was improved considerably, with a maximum return of 20.2 percent for a liquids transfer cost of $1.00 per million BTU, dropping to 10.7 percent at $3 per million BTU. Doubling the capital cost had about the same effect as before.



EL PASO BYPRODUCTS SCHEME

(ADJUSTED FOR GREAT PLAINS FLOWS)

FLOWS IN MILLIONS OF POUNDS PER YEAR

FIGURE 56

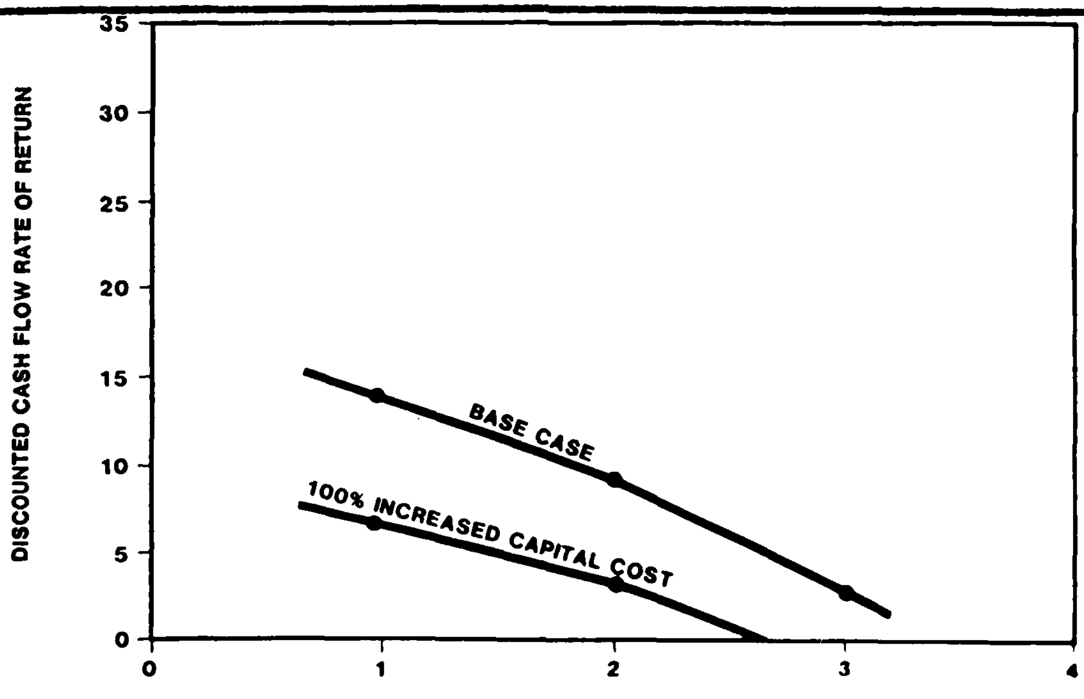


FIGURE 57

EL PASO CASE
(TOTAL PRODUCTS SCHEME)

TABLE 63

PRODUCT SLATE FOR EL PASO CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue $/Year
Benzene	85.4	0.157	13.41
Naphthalene	17.7	0.143	2.53
Creosote	47.1	0.090	4.24
Electrode Pitch	54.4	0.108	5.87
Carbon Black Feed	35.9	0.029	1.04
Natural Phenol	30.2	0.213	6.43
Refined Cresylics	27.5	0.383	10.53
			44.05

TABLE 64

CAPITAL INVESTMENT FOR EL PASO CASE

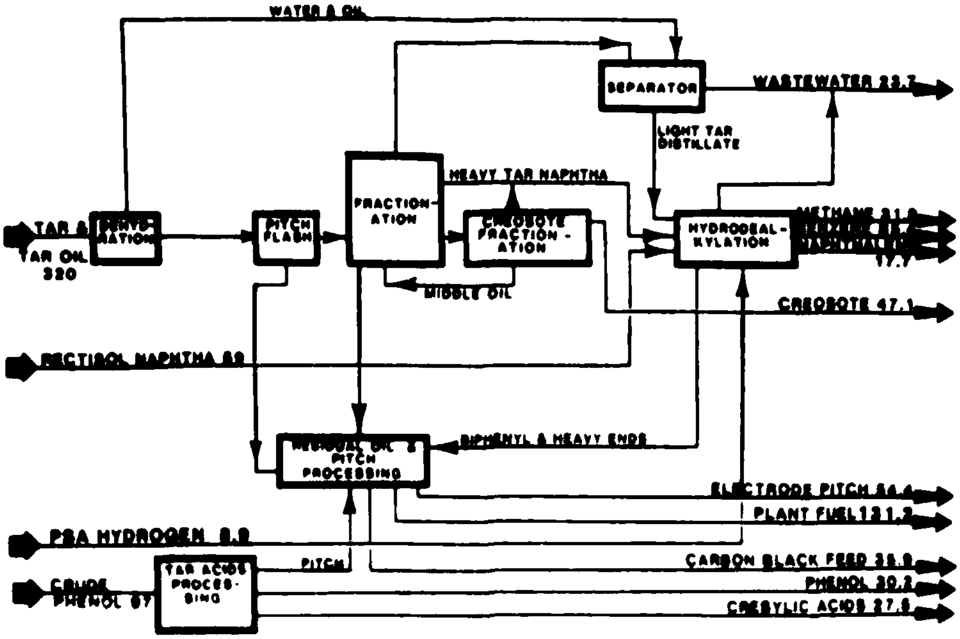
Process Unit	1986 Dollars
Dehydration	[illegible]2,000
Solids removal	1,449,000
Distillation	[illegible],[illegible]6,000
Hydrodealkylation	[illegible],[illegible]00,000
Residual oil and pitch	[illegible]012,000
Tar Acid Processing	6,16[illegible],000
Hydrogen Purification	[illegible],[illegible]9,000
Total Battery Limits Plant	[illegible]
[illegible]	[illegible],[illegible]19,000
Utilities	[illegible]
Contingency [illegible]	[illegible]
Total Depreciable Plant Cost	[illegible]
Pre-Production and Startup Expenses	[illegible]
Working Capital	[illegible]
Total Capital Investment	[illegible]

TABLE 65

OPERATING COSTS FOR EL PASO CASE

(1986 Dollars Per Year)

Fixed Operating Costs	
Labor and Supervision	2,229,000
Operating Supplies	455,000
Plant Overhead	335,000
Laboratory	550,000
Maintenance	2,442,000
Insurance and Taxes	1,462,000
Royalties	534,000
Total Fixed Cost	8,007,000
Corporate Overhead, R&D, Marketing	4,055,000
Total Fixed + Overhead Cost	12,062,000
Variable Operating Costs	
Utilities	1,366,000
Chemicals/Catalysts	280,000
Liquids Transfer Cost @ $1/MMBTU	7,548,000
Total Variable Cost @ $1/MMBTU	9,194,000
Total Variable Cost @ $2/MMBTU	16,742,000
Total Variable Cost @ $3/MMBTU	24,290,000



MODIFIED
EL PASO BYPRODUCTS SCHEME
(ADJUSTED FOR GREAT PLAINS FLOWS)
FLOWS IN MILLIONS OF POUNDS PER YEAR

FIGURE 58

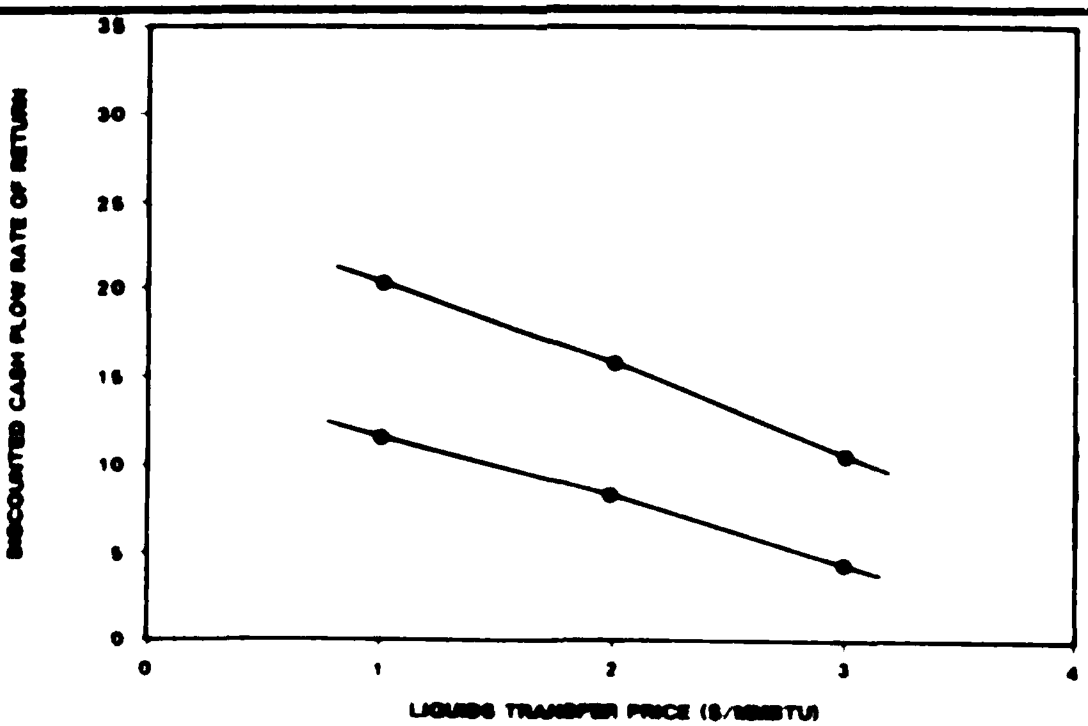


FIGURE 59

EL PASO CASE 2
(TOTAL PRODUCTS SCHEME)

TABLE 66

PRODUCT SLATE FOR MODIFIED EL PASO CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Benzene	85.4	0.157	13.41
Naphthalene	17.7	0.143	2.53
Creosote	47.1	0.090	4.24
Electrode Pitch	54.4	0.108	5.87
Carbon Black Feed	35.9	0.029	1.04
Natural Phenol	30.2	0.213	6.43
Refined Cresylics	27.5	0.383	10.53
Methane	4.0	0.343	1.37
			45.42

TABLE 67

CAPITAL INVESTMENT FOR MODIFIED EL PASO CASE

Process Unit	1986 Dollars
Dehydration	352,000
Distillation	2,776,000
Hydrodealkylation	13,500,000
Residual Oil and pitch	7,012,000
Tar Acid Processing	16,369,000
Total Battery Limits Plant	40,009,000
Offsites @ 50%	20,005,000
Subtotal	60,014,000
Contingency @ 25%	15,004,000
Total Depreciable Plant Cost	75,018,000
Pre Production Startup Expense	3,287,000
Working Capital	9,473,000
Total Capital Investment	87,778,000

TABLE 68

OPERATING COSTS FOR EL PASO CASE
(1986 Dollars Per Year)

Fixed Operating Costs	
Labor and Supervision	2,229,000
Operating Supplies	455,000
Plant Overhead	335,000
Laboratory	550,000
Maintenance	2,442,000
Insurance and Taxes	1,462,000
Royalties	534,000
Total Fixed Cost	8,007,000
Corporate Overhead, R&D, Marketing	4,055,000
Total Fixed + Overhead Cost	12,062,000
Variable Operating Costs	
Utilities	1,366,000
Chemicals/catalysts	280,000
Hydrogen Transfer Cost @ 1.70	2,716,000
Liquids Transfer Cost @ $1/MMBTU	7,548,000
Total Variable Cost @ $1/MMBTU	11,910,000
Total Variable Cost @ $2/MMBTU	19,458,000
Total Variable Cost @ $3/MMBTU	27,006,000

NON-HYDROGENATED EL PASO CASE

After observing the major effect that hydrogen costs could exert on overall economics, the El Paso scheme was modified further by eliminating the hydrodealkylation unit. The naphtha streams were simply returned to plant fuel and received a BTU credit equal to the liquids transfer charge (Figure 60).

The product slate, capital investment, and operating costs for this case are given in Tables 69, 70 and 71, respectively. Results of the economic analysis are graphed in Figure 61. The maximum discounted cash flow rate of return dropped sharply, to 10.8 percent. This result suggests that the benzene product stream is of major importance to the economics of by-product refining.

CRESYLIC ACIDS CASE

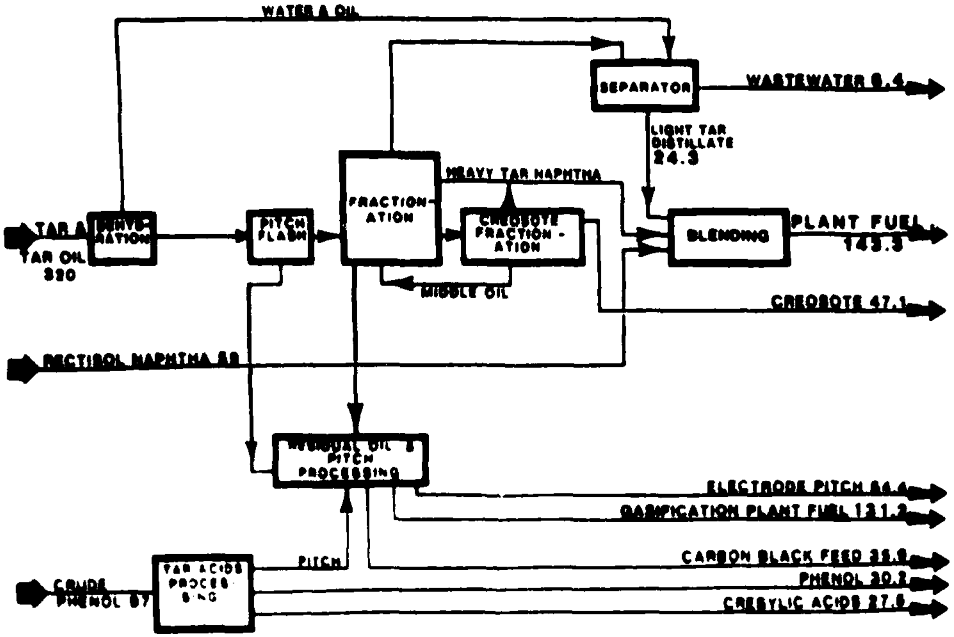
It had been assumed that the tar acids could be the most valuable constituents in the by-products. Because the Great Plains plant would have the option of continuing to burn any of the liquid by-products instead of attempting to upgrade them, the El Paso flow scheme was modified to process only the tar acids. All other liquids were returned to plant fuel. A co-product of the phenols extraction process would be an aromatic raffinate stream which could be sold for more than plant fuel value (Figure 62).

The product slate, capital investment, and operating costs for this case are given in Table 72, 73 and 74 respectively. The results of the economic analysis are shown in Figure 63. The results were not encouraging, with a maximum rate of return of 12.8 percent at a liquids transfer cost of $1.00 per million BTU, and only 5.0 percent for a liquids transfer cost of $3.00 per million BTU. Doubling the estimated plant cost dropped the rate of return to zero at a liquids transfer cost of $3.00 per million BTU.

PHENOLS ONLY CASE

To simplify the flow scheme further, and eliminate the cost of tar oil distillation, a case was designed in which only the crude phenol stream was processed. All other streams continued to be utilized as plant fuel (Figure 64).

The product slate, capital investment, and operating costs for this case are given in Tables 75, 76 and 77, respectively. Results of the economic analysis are shown in Figure 65. Return on investment was less favorable than for the previous case, in which phenols were extracted from both the crude phenol stream and the tar oil stream. The maximum discounted cash flow rate of return was 11.0 percent for a liquids transfer cost of $1.00 per million BTU, decreasing to 4.7 percent at $3.00 per million BTU. Increasing the capital cost by 100 percent resulted in a negative rate of return when using the highest liquids transfer cost.



NON-HYDROGENATED
EL PASO BYPRODUCTS SCHEME
(ADJUSTED FOR GREAT PLAINS FLOWS)
FLOWS IN MILLIONS OF POUNDS PER YEAR

FIGURE 60

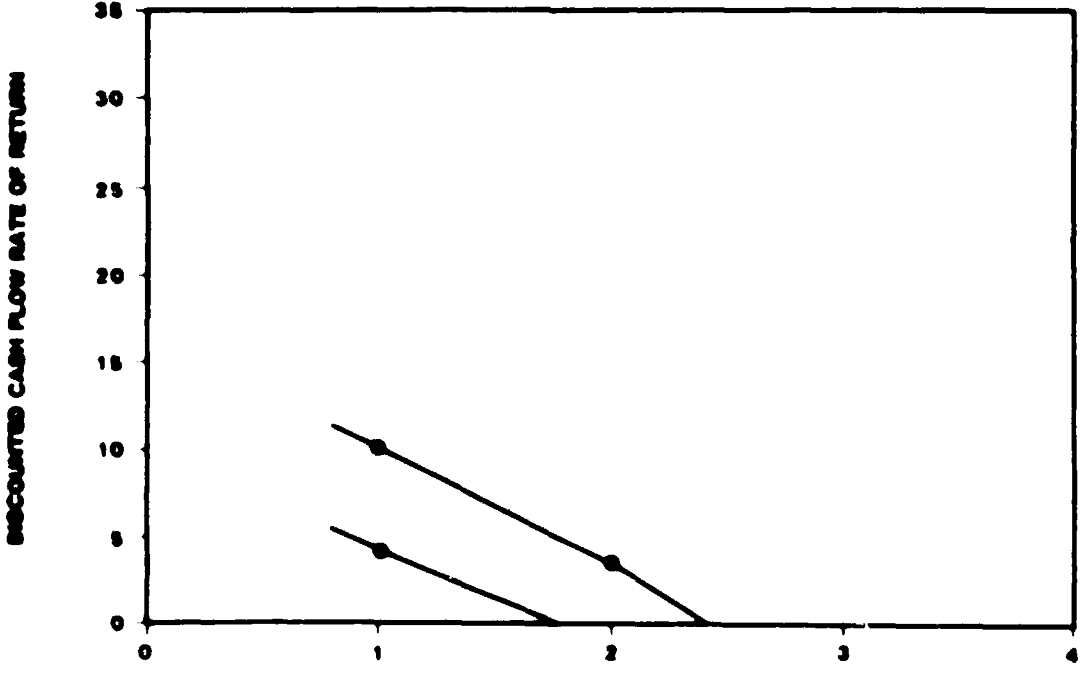


FIGURE 61

NON-HYDROTREATING EL PASO CASE
(BTX TO PLANT FUEL)

TABLE 69

PRODUCT SLATE FOR NON-HYDROGENATED EL PASO CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Creosote	47.1	0.090	4.24
Electrode Pitch	54.4	0.108	5.87
Carbon Black Feed	35.9	0.029	1.04
Natural Phenol	30.2	0.213	6.43
Refined Cresylics	27.5	0.383	10.53
			28.11

TABLE 70

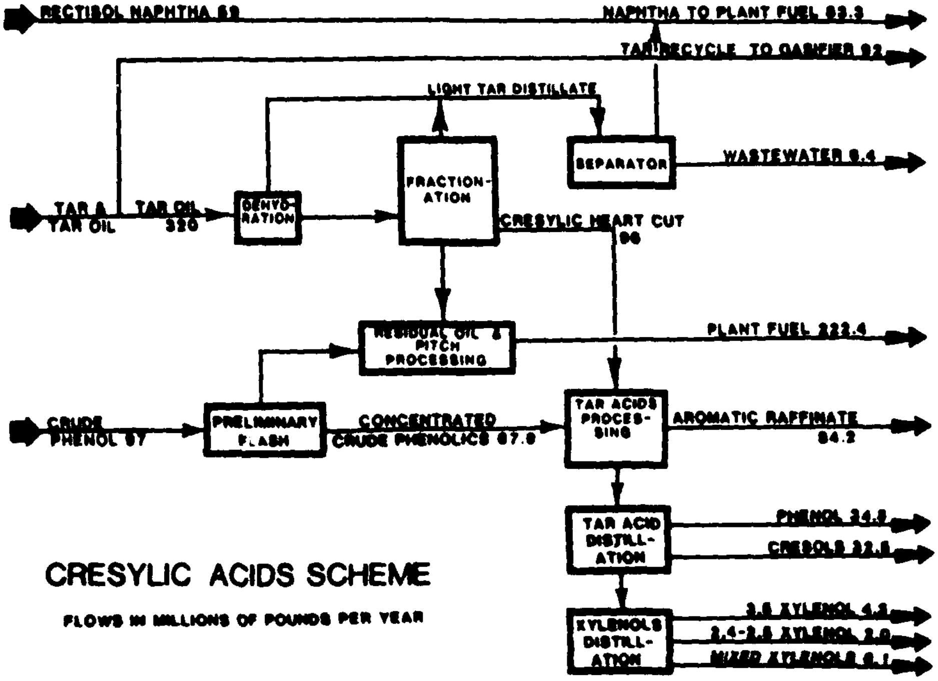
CAPITAL INVESTMENT FOR NON-HYDROGENATED EL PASO CASE

Process Unit	1986 Dollars
Dehydration	352,000
Distillation	2,776,000
Residual Oil and pitch	7,012,000
Tar Acid Processing	16,369,000
Total Battery Limits Plant	26,479,000
Offsites @ 50%	13,239,000
Subtotal	39,718,000
Contingency @ 25%	9,929,000
Total Depreciable Plant Cost	49,648,000
Pre-Production Startup Expense	1,986,000
Working Capital	6,504,000
Total Capital Investment	58,138,000

TABLE 71

OPERATING COSTS FOR NON-HYDROGENATED EL PASO CASE
(1986 Dollars Per Year)

Fixed Operating Costs	
Labor and Supervision	1,783,000
Operating Supplies	364,000
Plant Overhead	268,000
Laboratory	440,000
Maintenance	1,954,000
Insurance and Taxes	1,170,000
Royalties	427,000
Total Fixed Cost	6,406,000
Corporate Overhead, R&D, Marketing	3,243,000
Total Fixed + Overhead Cost	9,649,000
Variable Operating Costs	
Utilities, Chemicals	1,152,000
Liquids Transfer Cost @ $1/MMBTU	5,470,000
Total Variable Cost @ $1/MMBTU	7,829,000
Total Variable Cost @ $2/MMBTU	13,298,000
Total Variable Cost @ $3/MMBTU	18,769,000



CRESYLIC ACIDS SCHEME

FLOWS IN MILLIONS OF POUNDS PER YEAR

FIGURE 62

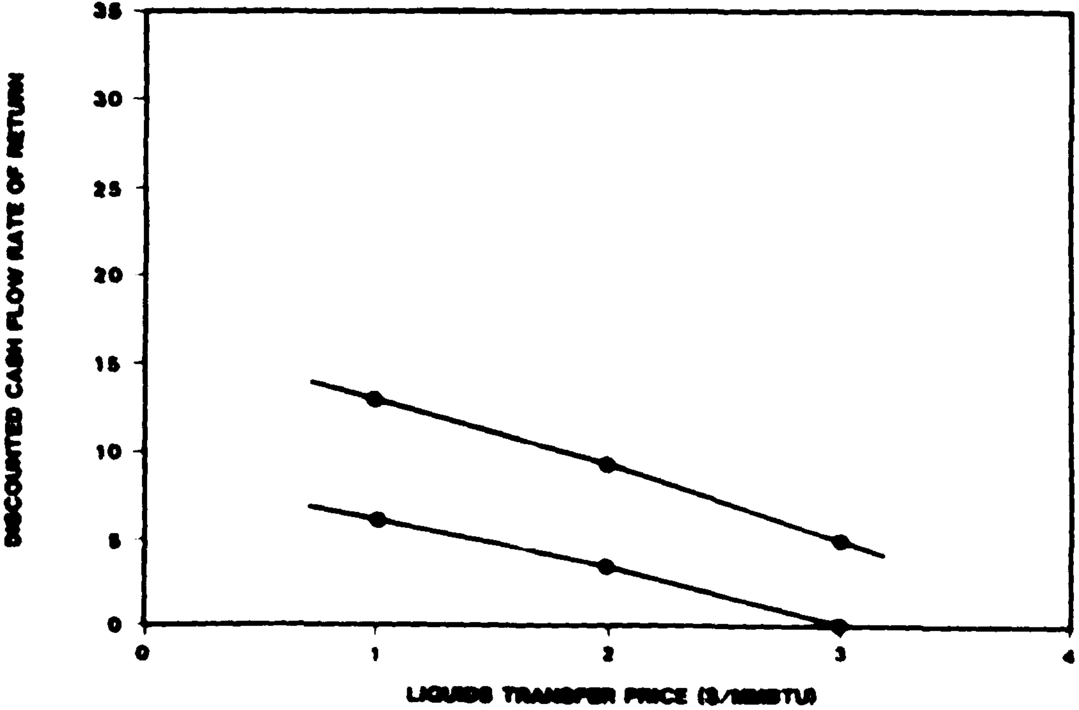


FIGURE 63

CRESYLIC ACID SCHEME

(PHENOL & TAR OIL)

TABLE 72

PRODUCT SLATE FOR CRESYLIC ACIDS CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Phenol	34.8	0.213	7.41
Cresols	32.5	0.383	12.45
Mixed Xylenols	12.4	0.503	6.45
Aromatic Raffinate	84.2	0.060	5.05
			31.36

TABLE 73

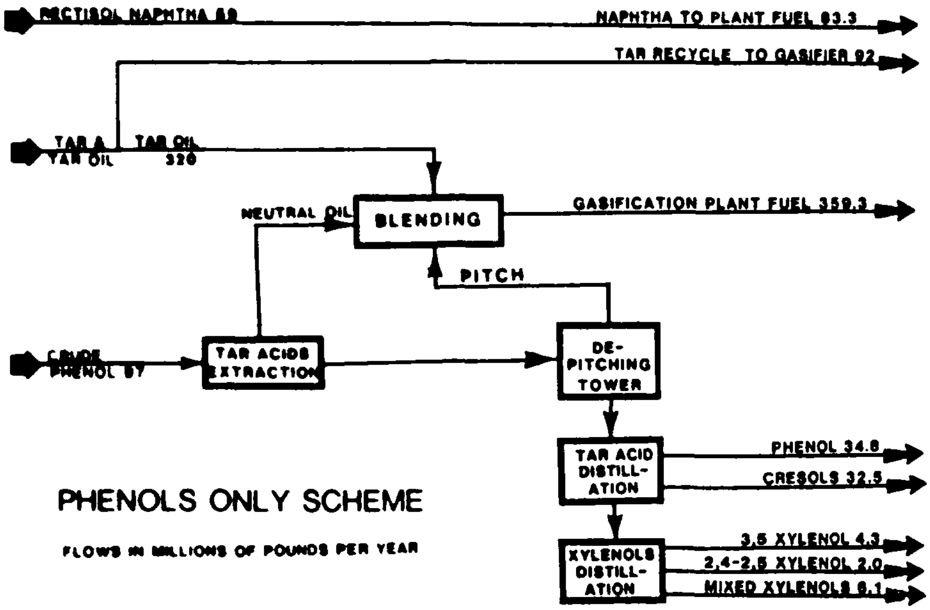
CAPITAL INVESTMENT FOR CRESYLIC ACIDS CASE

Process Unit	1986 Dollars
Dehydration	352,000
Distillation	2,776,000
Residual Oil and pitch	7,012,000
Tar Acid Processing	22,424,000
Phenol Fractionation	2,300,000
Total Battery Limits Plant	34,864,000
Offsites @ 50%	17,432,000
Subtotal	52,296,000
Contingency @ 25%	13,074,000
Total Depreciable Plant Cost	65,370,000
Pre-Production Startup Expense	2,615,000
Working Capital	6,680,000
Total Capital Investment	74,665,000

TABLE 74

OPERATING COSTS FOR CRESYLIC ACIDS CASE
(1986 Dollars Per Year)

Fixed Operating Costs	
Labor and Supervision	2,229,000
Operating Supplies	362,000
Plant Overhead	335,000
Laboratory	550,000
Maintenance	1,942,000
Insurance and Taxes	1,163,000
Royalties	376,000
Total Fixed Cost	6,957,000
Corporate Overhead, R&D, Marketing	3,854,000
Total Fixed + Overhead Cost	9,811,000
Variable Operating Costs	
Utilities	1,086,000
Chemicals catalysts	223,000
Liquids Transfer Cost @ $1/MMBTU	4,030,000
Total Variable Cost @ $1/MMBTU	5,339,000
Total Variable Cost @ $2/MMBTU	9,369,000
Total Variable Cost @ $3/MMBTU	13,399,000



PHENOLS ONLY SCHEME

FLOWS IN MILLIONS OF POUNDS PER YEAR

FIGURE 64

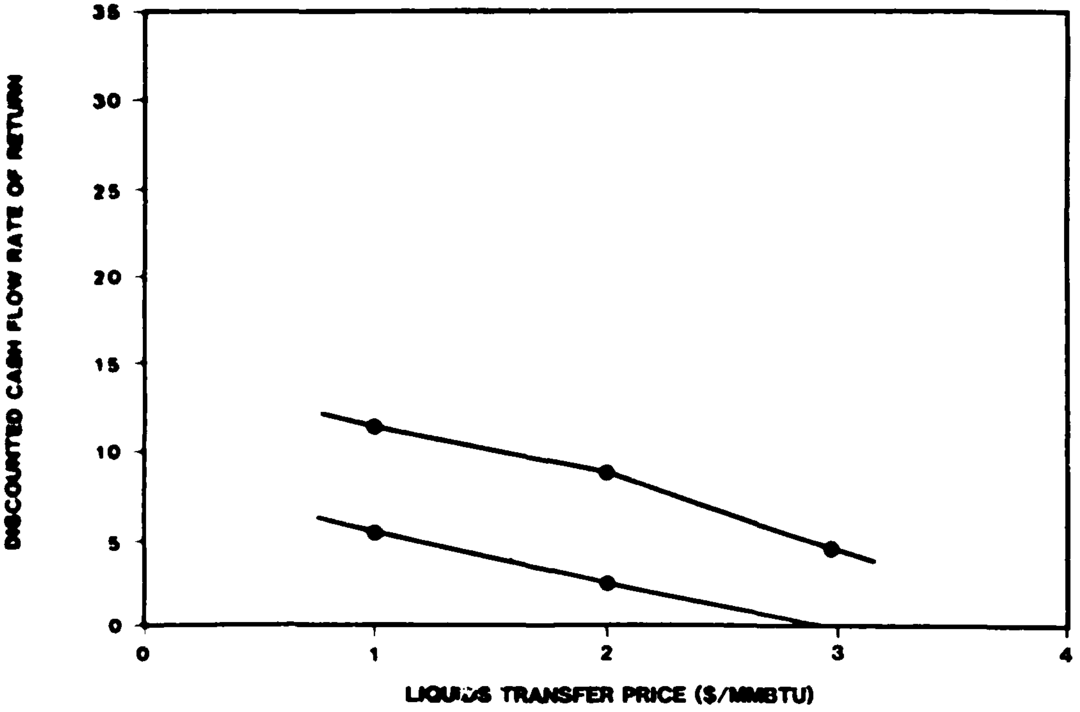


FIGURE 65

CRESYLIC ACID SCHEME
(PHENOL ONLY)

TABLE 75

PRODUCT SLATE FOR PHENOLS ONLY CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Phenol	30.2	0.213	6.43
Cresols	21.0	0.383	8.04
Xylenols	6.5	0.503	3.27
			17.74

TABLE 76

CAPITAL INVESTMENT FOR PHENOLS ONLY CASE

Process Unit	1986 Dollars
Cresol Distillation	2,300,000
Xylenol Distillation	2,300,000
Tar Acid Processing	16,369,000
Total Battery Limits Plant	20,969,000
Offsites @ 50%	10,985,000
Subtotal	31,454,000
Contingency @ 25%	7,863,000
Total Depreciable Plant Cost	39,317,000
Pre-Production Startup Expense	1,573,000
Working Capital	3,840,000
Total Capital Investment	44,730,000

TABLE 77

OPERATING COSTS FOR FUELS ONLY CASE

(1986 Dollars Per Year)

Fixed Operating Costs	
Labor and Supervision	1,493,000
Operating Supplies	362,000
Plant Overhead	268,000
Laboratory	550,000
Maintenance	1,301,000
Insurance and Taxes	779,000
Royalties	216,000
Total Fixed Cost	4,969,000
Corporate Overhead, R&D, Marketing	1,641,000
Total Fixed + Overhead Cost	6,610,000
Variable Operating Costs	
Utilities	760,000
Chemicals/catalysts	223,000
Liquids Transfer Cost @ $1/MMBTU	1,860,000
Total Variable Cost @ $1/MMBTU	2,843,000
Total Variable Cost @ $2/MMBTU	4,703,000
Total Variable Cost @ $3/MMBTU	6,563,000

GRADY/ANG CASE

Another source of cost estimates for an integrated products upgrading scheme was a feasibility study carried out for Great Plains Gasification Associates in 1983 by R. M. Grady & Associates. The flow scheme (Figure 66) is basically the same as the original El Paso scheme, except that phenols are extracted from both the crude phenol stream and the middle oil cut from the tar oil stream. Hydrotreating instead of hydrodealkylation of the naphtha is proposed to yield gasoline plus a solvent oil.

The product slate, capital costs, and operating costs are given in Tables 78, 79 and 80, respectively. The estimated capital cost is only $56 million, compared to $95 million for the El Paso case. As expected, this has a very favorable effect on the economics (Figure 67). Maximum rate of return is 28.9 percent compared to 14.3 percent calculated for the El Paso case.

GRADY/EL PASO CASE

Comparison of the capital cost data provided in the Grady/ANG case and the El Paso case reveals considerably more detail in the El Paso case, and suggestions of the expenditure of considerably more engineering design effort. Further comparison reveals that the major discrepancy is in the estimated cost of the tar acid extraction unit. The Grady scheme uses a caustic extraction procedure whereas the El Paso case is based on Lurgi's Phenoraffin solvent extraction process. To illustrate the effect of this unit on the economics, the Grady/ANG case was re-run by substituting El Paso's cost for the tar acid extraction unit in place of Grady's cost estimate.

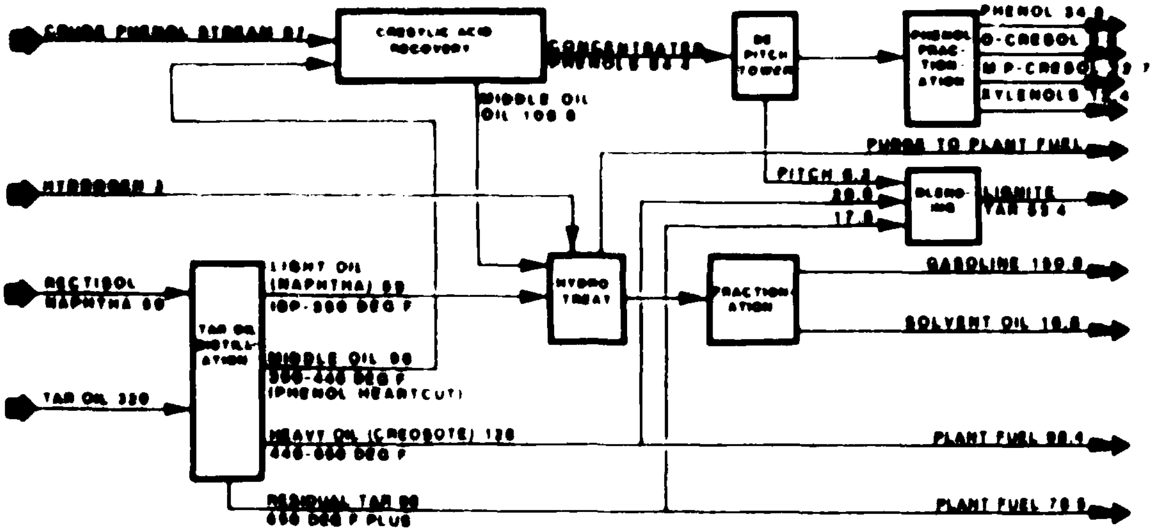
The product slate, capital cost and operating cost for this case are given in Tables 81, 82 and 83, respectively. Figure 68 shows the results of the economic analysis. The maximum return on investment was calculated to be 15.4 percent, very similar to the 14.3 percent obtained in the El Paso case. This return drops to 7.8 percent at a $3.00 per million BTU transfer cost for the liquids. The high value declines by about seven percent if the capital cost for the facility is doubled.

The results of this case clearly illustrate the crucial importance of a reliable cost estimate for the tar acids extraction unit. While the Lurgi estimate provided to the El Paso project may have been reasonably valid at that time, no Phenoraffin units have been built since 1963. There may be many questions about such old cost estimates being accurate, especially in today's environmental setting. The Grady estimate is not convincing in its depth of detail. No reliable cost estimate is available.

GRADY NON-HYDROTREATING CASE

As was done with the El Paso scheme, the Grady/ANG flow sheet was rearranged to eliminate the hydrotreating step (Figure 69). The product slate, capital costs and operating costs are given in Tables 84, 85 and 86, respectively.

The economic results are shown in Figure 70. The maximum rate of return (at a liquids transfer cost of $1.00 per million BTU) increases slightly to 32.0 percent from 28.9 percent. This is in contrast to the El Paso case, where the return dropped sharply when the hydrogenation step was eliminated.



GRADY/ANG SCHEME WITH HYDROTREATING

FIGURE 66

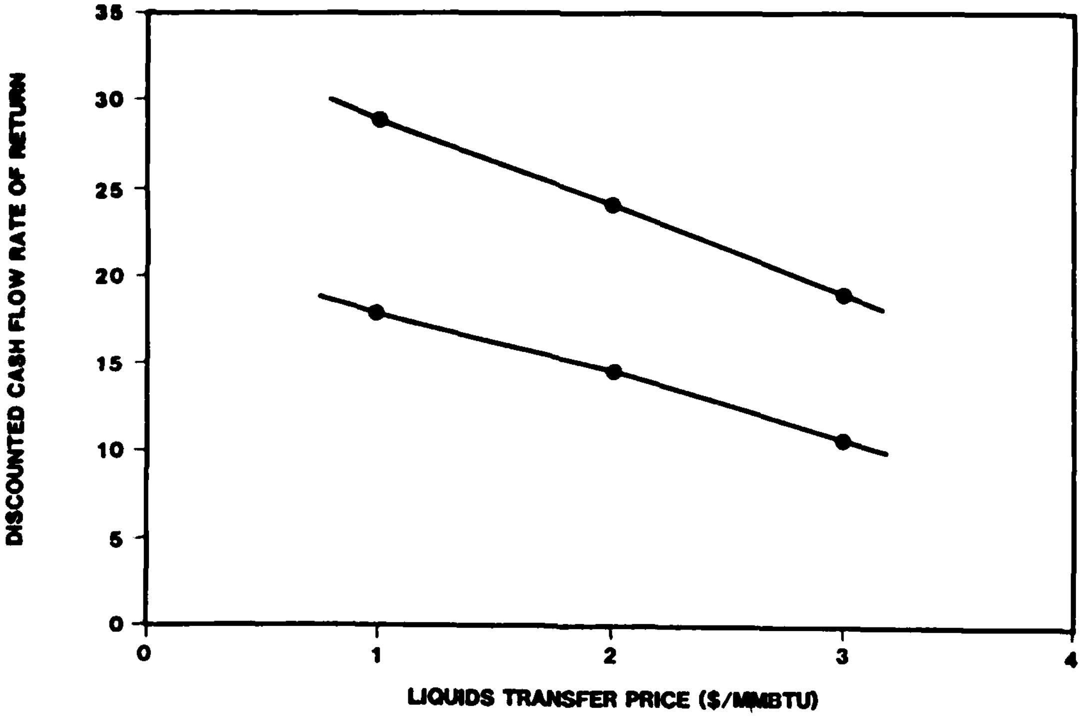


FIGURE 67

GRADY/ANG
(TOTAL PRODUCTS SCHEME)

TABLE 78

PRODUCT SLATE FOR GRADY/ANG CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Phenol	34.8	0.213	7.41
O-Cresol	9.8	0.503	4.93
M,P-Cresol	22.7	0.551	12.51
Xylenols	12.4	0.503	6.24
Lignite Tar	53.4	0.108	5.77
Gasoline	150.8	0.081	12.21
Solvent Oil	16.8	0.108	1.81
			50.88

TABLE 79

CAPITAL INVESTMENT FOR GRADY/ANG CASE

Process Unit	1986 Dollars
Depitching Tower	3,250,000
Tar Distillation	2,200,000
Hydrotreating	6,790,000
Tar Acid Processing	3,040,000
Phenol Fractionation	4,830,000
Total Battery Limits Plant	20,110,000
Offsites @ 35%	7,040,000
Subtotal	27,150,000
Engineering @ 20%	5,430,000
	32,580,000
Contingency @ 35%	11,400,000
Total Depreciable Plant Cost	43,980,000
Pre-Production Startup Expense	1,759,000
Working Capital	10,300,000
Total Capital Investment	56,039,000

TABLE 80

OPERATING COSTS FOR GRADY/ANG CASE
(1986 Dollars Per Year)

Fixed Operating Costs	5,604,000
Corporate Overhead, R&D, Marketing	4,055,000
Total Fixed + Overhead Cost	9,609,000
Variable Operating Costs	
Utilities	2,359,000
Chemicals/catalysts	938,000
Hydrogen Transfer Cost	814,000
Liquids Transfer Cost @ $1/MMBTU	6,248,000
Total Variable Cost @ $1/MMBTU	10,359,000
Total Variable Cost @ $2/MMBTU	16,607,000
Total Variable Cost @ $3/MMBTU	22,855,000

TABLE 81

PRODUCT SLATE FOR GRADY/EL PASO CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Phenol	34.8	0.213	7.41
O-Cresol	9.8	0.503	4.93
M,P-Cresol	22.7	0.551	12.51
Xylenols	12.4	0.503	6.24
Lignite Tar	53.4	0.108	5.77
Gasoline	150.8	0.081	12.21
Solvent Oil	16.8	0.108	1.81
			50.88

TABLE 82

CAPITAL INVESTMENT FOR GRADY/EL PASO CASE

Process Unit	1986 Dollars
Depitching Tower	3,250,000
Tar Distillation	2,200,000
Hydrotreating	6,790,000
Tar Acid Processing	24,733,000
Phenol Fractionation	4,830,000
Total Battery Limits Plant	41,803,000
Offsites @ 35%	14,631,000
Subtotal	56,434,000
Engineering @ 20%	11,287,000
	67,721,000
Contingency @ 35%	23,702,000
Total Depreciable Plant Cost	91,423,000
Pre-Production Startup Expense	3,657,000
Working Capital	10,300,000
Total Capital Investment	105,380,000

TABLE 83

OPERATING COSTS FOR GRADY/EL PASO CASE
(1986 Dollars Per Year)

Fixed Operating Costs	9,143,000
Corporate Overhead, R&D, Marketing	4,055,000
Total Fixed + Overhead Cost	13,198,000
Variable Operating Costs	
Utilities	2,359,000
Chemicals/catalysts	938,000
Hydrogen Transfer Cost	814,000
Liquids Transfer Cost @ $1/MMBTU	6,248,000
Total Variable Cost @ $1/MMBTU	10,359,000
Total Variable Cost @ $2/MMBTU	16,607,000
Total Variable Cost @ $3/MMBTU	22,855,000

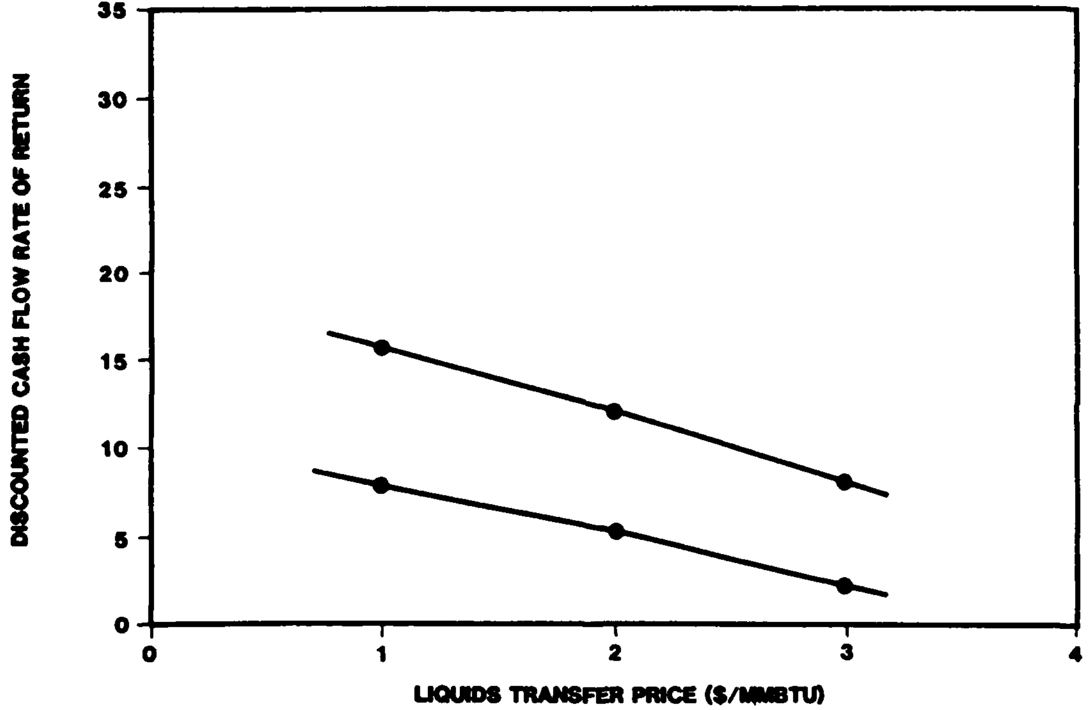
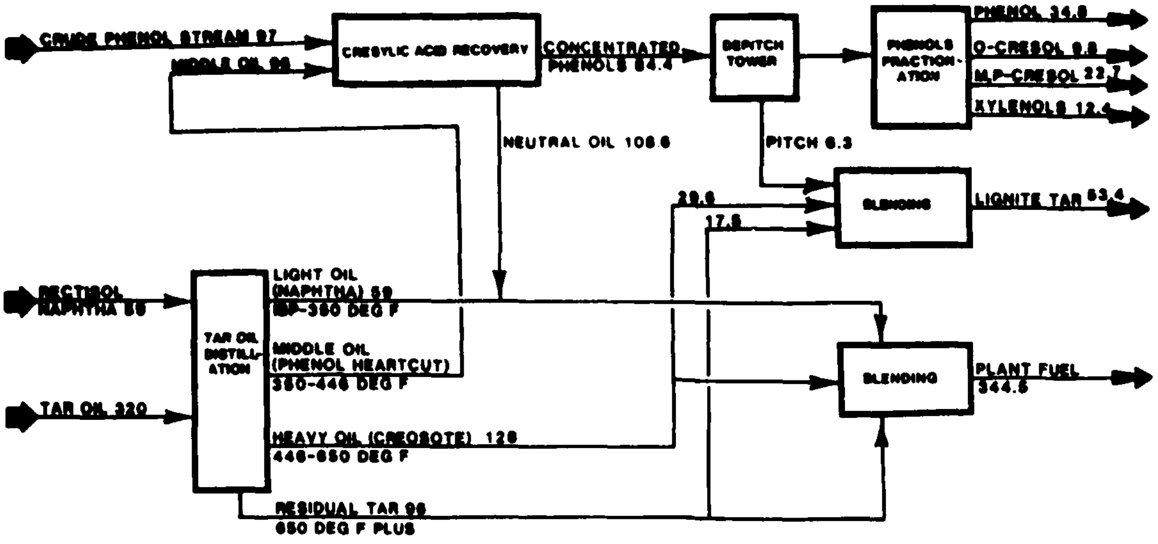


FIGURE 68

GRADY/ANG 2
(TOTAL PRODUCTS SCHEME)



GRADY/ANG SCHEME WITHOUT HYDROTREATING

FIGURE 69

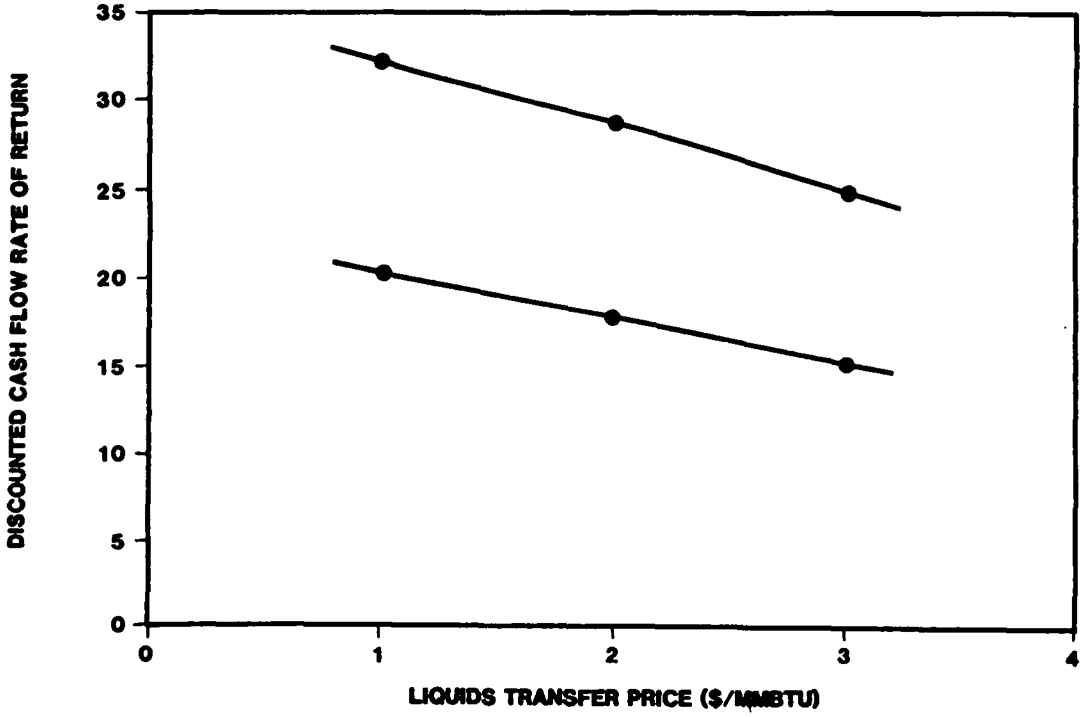


FIGURE 70

NON-HYDROTREATING GRADY/ANG

TABLE 84

PRODUCT SLATE FOR GRADY/ANG NON-HYDROTREATING CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Phenol	34.8	0.213	7.41
O-Cresol	9.8	0.503	4.93
M,P-Cresol	22.7	0.551	12.51
Xylenols	12.4	0.503	6.24
Lignite Tar	53.4	0.108	5.77
			36.86

TABLE 85

CAPITAL INVESTMENT FOR GRADY/ANG NON-HYDROTREATING CASE

Process Unit	1986 Dollars
Depitching Tower	3,250,000
Tar Distillation	2,200,000
Tar Acid Processing	3,040,000
Phenol Fractionation	4,830,000
Total Battery Limits Plant	13,320,000
Offsites @ 35%	4,662,000
Subtotal	17,982,000
Engineering @ 20%	3,596,000
	21,578,000
Contingency @ 35%	7,552,000
Total Depreciable Plant Cost	29,130,000
Pre-Production Startup Expense	1,165,000
Working Capital	7,815,000
Total Capital Investment	38,110,000

TABLE 86

OPERATING COSTS FOR GRADY/ANG NON-HYDROTREATING CASE

(1986 Dollars Per Year)

Fixed Operating Costs	3,811,000
Corporate Overhead, R&D, Marketing	3,073,000
Total Fixed + Overhead Cost	6,884,000
Variable Operating Costs	
Utilities	1,769,000
Chemicals/catalysts	938,000
Liquids Transfer Cost @ $1/MMBTU	3,330,000
Total Variable Cost @ $1/MMBTU	6,037,000
Total Variable Cost @ $2/MMBTU	9,367,000
Total Variable Cost @ $3/MMBTU	12,697,000

GRADY/EL PASO NON-HYDROTREATING CASE

The previous case was modified by again substituting El Paso's estimate of the cost for the tar acid extraction unit. The product slate, capital cost and operating cost are given in Tables 87, 88 and 89, respectively.

Figure 71 illustrates the economic results. The maximum discounted cash flow rate of return is 17.4 percent compared to the previously obtained value of 15.4 percent for the comparable hydrotreated case.

BENZENE ONLY

Although the Grady hydrotreated versus non-hydrotreated cases produced seemingly equivocal results, the El Paso cases indicated a strong economic incentive for producing benzene. There are a number of options for producing benzene, of which four were investigated (Figure 72). These four options are defined as follows:

Benzene only	-	Naphtha stream to Litol process
BTX option	-	Naphtha stream to Unibon hydrotreating followed by Sulfolane extraction
Benzene + Phenol	-	Naphtha and phenol streams to Dynaphen process
Dynaphen II	-	Same as preceding case but add tar acids from tar oil stream

The first case involves processing only the naphtha stream by hydrodealkylation to produce benzene. Houdry's Litol process was selected.

The product slate, capital cost and operating cost for this case are given in Table 90. Results of the economic analysis are shown in Figure 73. The maximum rate of return was calculated to be 23.3 percent at a liquids transfer cost of $1.00 per million BTU, falling to 17.0 percent at $3.00 per million BTU. Increasing the capital cost by 100 percent decreased the rate of return from 23.3 to 13.6 percent.

BTX ONLY CASE

An alternate method of treating the naphtha stream is to use a solvent extraction process. In this case a mixed benzene, toluene, xylene (BTX) product stream would result. The raw naphtha stream would have to be subjected to mild hydrotreatment before it would be acceptable to the solvent extraction process.

This case is based on UOP's LT Unibon process for hydrotreating, and their Sulfolane process for extraction. The product slate, capital cost and operating cost are given in Table 91. Economic results are seen in Figure 74. The maximum rate of return was found to be 26.8 percent at a liquids transfer cost of $1.00 per million BTU. This is essentially equivalent to the result obtained for the Litol/benzene case. However, the assumed product revenues are overly optimistic because prices for the pure components were used.

TABLE [illegible]

PRODUCT SLATE FOR GRADY/EL PASO NON-HYDROTREATING CASE

Product	Production, MM Pounds Per Year	Price, $/lb	Revenue, $/Year
Phenol	34.8	0.213	7.41
O-Cresol	9.8	0.503	4.93
M,P-Cresol	22.7	0.551	12.51
Xylenols	12.4	0.503	6.24
Lignite Tar	53.4	0.108	5.77
			36.86

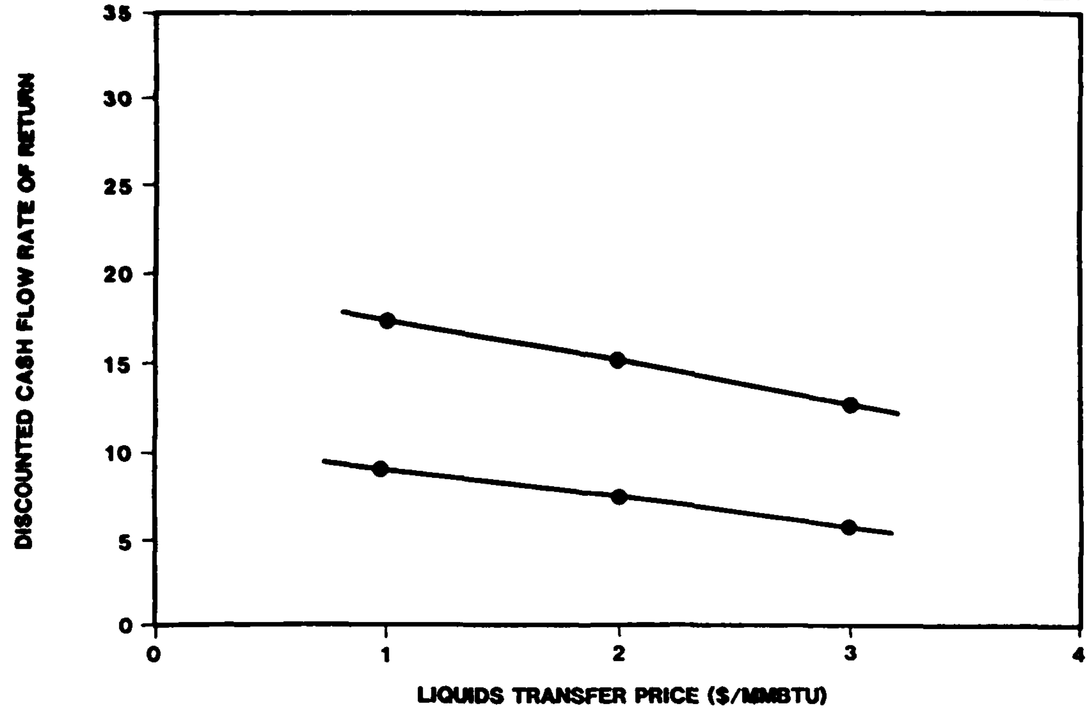


FIGURE 71

NON-HYDROTREATING GRADY/ANG 2

TABLE 88

CAPITAL INVESTMENT FOR GRADY/EL PASO NON-HYDROTREATING CASE

Process Unit	1986 Dollars
Depitching Tower	3,250,000
Tar Distillation	2,200,000
Tar Acid Processing	22,424,000
Phenol Fractionation	4,830,000
Total Battery Limits Plant	32,704,000
Offsites @ 35%	11,446,000
Subtotal	44,150,000
Engineering @ 20%	8,830,000
	52,980,000
Contingency @ 35%	18,543,000
Total Depreciable Plant Cost	71,523,000
Pre-Production Startup Expense	1,165,000
Working Capital	7,815,000
Total Capital Investment	80,503,000

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VOLUME 1 MARKET ASSESSM..(U) NORTH DAKOTA UNIV GRAND
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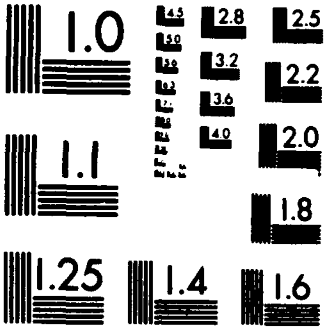

MICROCOPY RESOLUTION TEST CHART
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TABLE 89

OPERATING COSTS FOR GRADY/EL PASO
NON-HYDROTREATING CASE
(1986 Dollars Per Year)

Fixed Operating Costs	3,811,000
Corporate Overhead, R&D, Marketing	3,073,000
Total Fixed + Overhead Cost	6,884,000
Variable Operating Costs	
Utilities	1,769,000
Chemicals/catalysts	938,000
Liquids Transfer Cost @ $1/MMBTU	3,330,000
Total Variable Cost @ $1/MMBTU	6,037,000
Total Variable Cost @ $2/MMBTU	9,367,000
Total Variable Cost @ $3/MMBTU	12,697,000

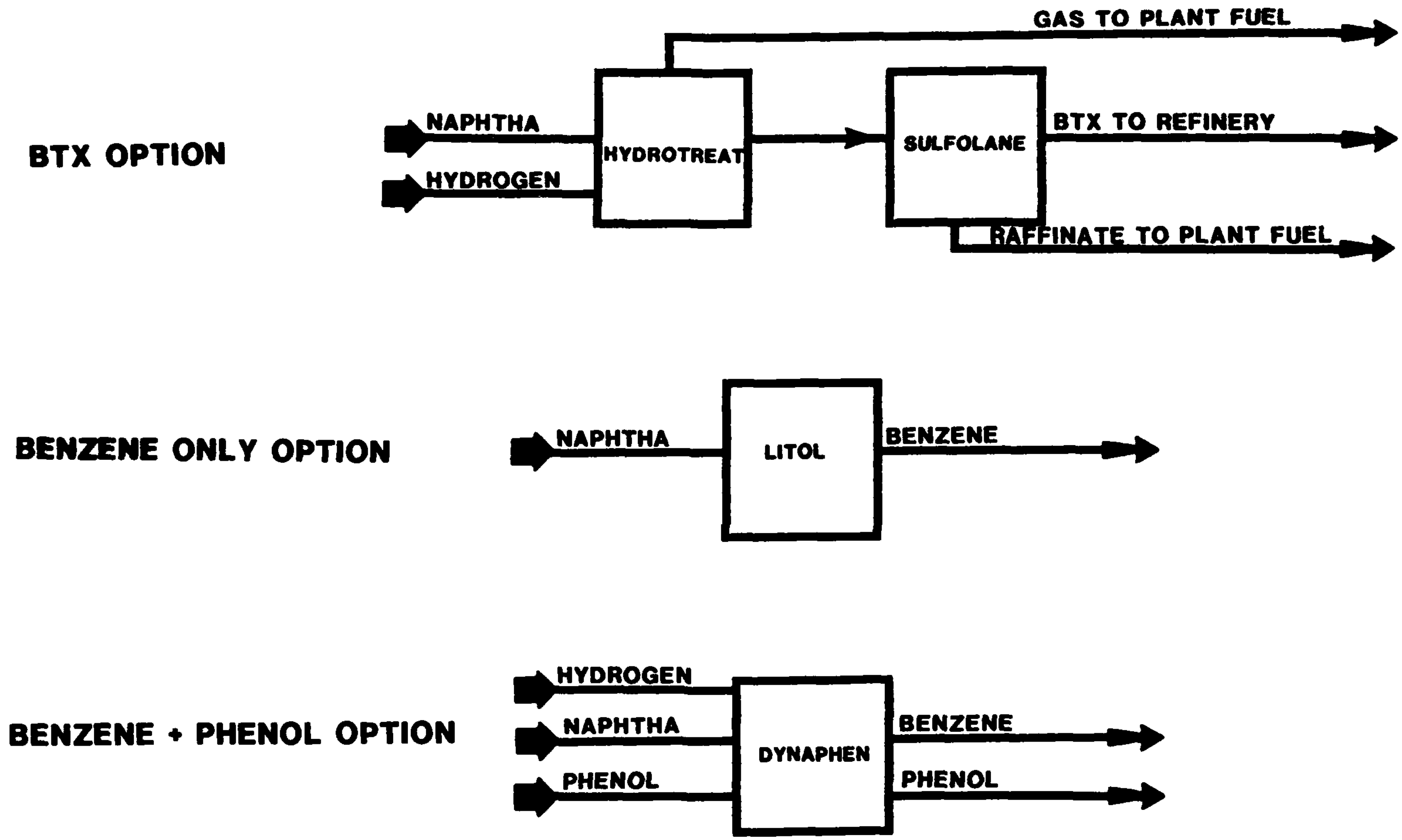


FIGURE 72

BENZENE PROCESS OPTIONS

TABLE 90

ECONOMIC PARAMETERS FOR BENZENE ONLY CASE
(Processing Naphtha Only--Litol Hydrodealkylation)

Product	
Benzene @ 7.34 lb/gal	32,000,000 lb/year
Revenue @ $0.157/lb	$5,024,000
Capital Cost	
Depreciable Capital Cost	$7,500,000
Working Capital	837,000
Pre-Production Startup Expense	300,000
	$8,637,000
Operating Cost	
Fixed Operating Cost	$432,000
Hydrogen @ 1.70	380,000
Liquids transfer net cost @ $1/MMBTU	576,000
Total Operating Cost @ $1/MMBTU	$1,388,000
Total Operating Cost @ $2/MMBTU	$1,964,000
Total Operating Cost @ $3/MMBTU	$2,540,000

TABLE 91

ECONOMIC PARAMETERS FOR BTX CASE
(Processing Naphtha Only--LT Unibon Plus Sulfolane)

Product Slate

Product	Million Pounds/year	Dollars Per Pound	Dollars Per Year
Benzene	21.2	0.157	$3,328,000
Toluene	8.8	0.125	1,100,000
Xylene	1.8	0.160	288,000
			$4,716,000

Capital Cost

Depreciable Capital Cost	$6,000,000
Working Capital	786,000
Pre-Production Startup Expense	280,000
	$7,066,000

Operating Cost

Fixed Operating Cost	$403,000
Hydrogen	190,000
Liquids Transfer Net Cost @ $1/MMBTU	554,000
Total Operating Cost @ $1/MMBTU	$1,147,000
Total Operating Cost @ $2/MMBTU	$1,701,000
Total Operating Cost @ $3/MMBTU	$2,255,000

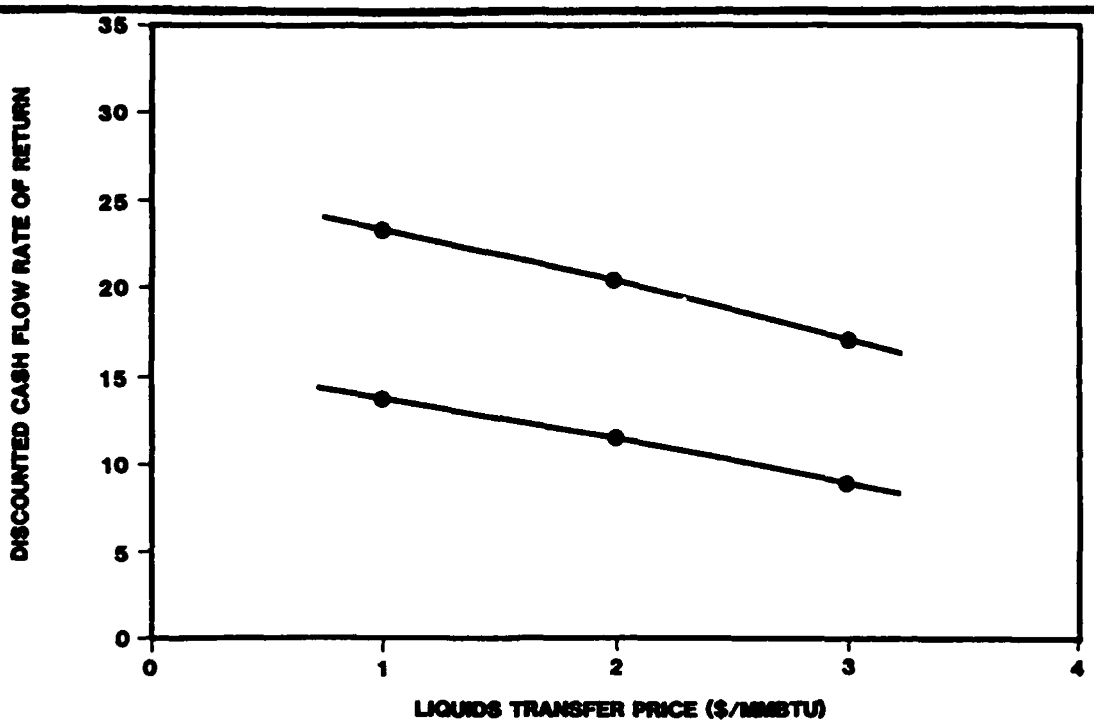


FIGURE 73

LITOL BENZENE
(NAPHTHA ONLY)

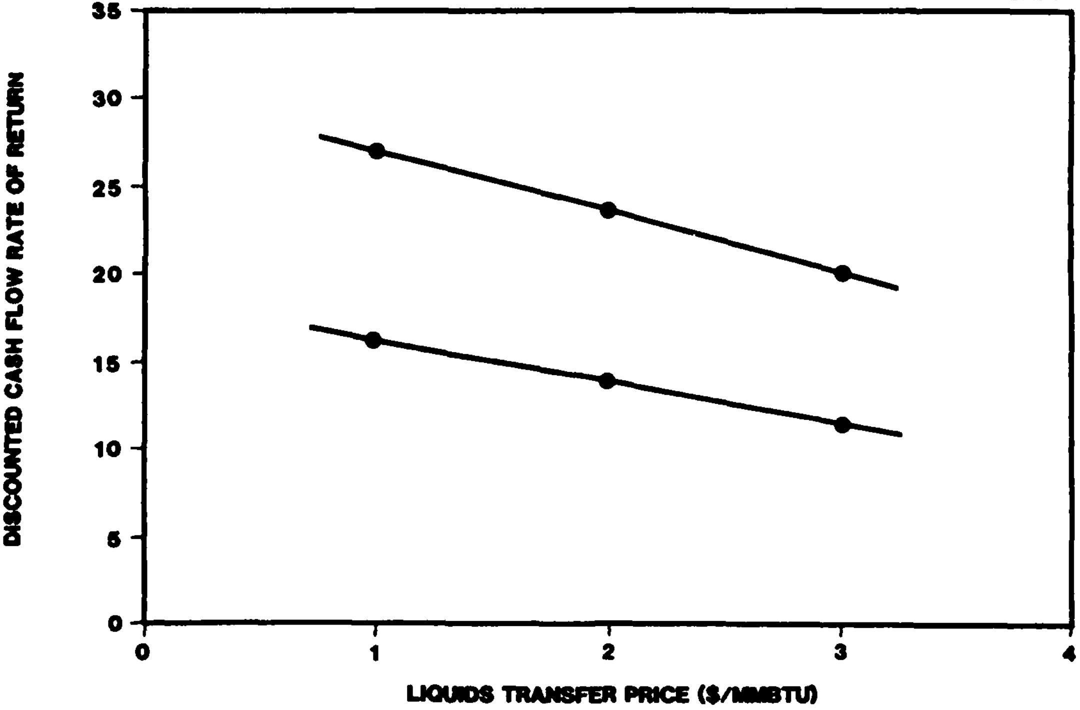


FIGURE 74

UNIBON & SULFOLANE
(NAPHTHA ONLY)

BENZENE PLUS PHENOL CASE

Having demonstrated the attractiveness of producing only benzene as a product in a relatively simple processing scheme, it was desirable to study the effect of co-producing phenol from the crude phenol stream. Because phenol is worth even more than benzene, producing it as a co-product instead of converting it to benzene seems logical.

HRI has a process still in the development stage, Dynaphen, which co-produces benzene and phenol from a mixed stream containing alkylated aromatics and phenols.

Estimated economic parameters for a Dynaphen facility processing the Great Plains naphtha and phenols streams are given in Table 92. With a simplistic assumption of 100 percent recovery, the product slate would be 35 million pounds of benzene and 51 million pounds of phenol per year.

Results of the economic analysis are seen in Figure 75. The maximum rate of return is 35.9 percent at a liquids transfer value of $1.00 per million BTU. At a transfer cost of $3.00 per million BTU, the rate of return drops to 22.5 percent. If the capital cost is then doubled, the return drops to 13.6 percent.

Although this appears to be the most attractive of the schemes investigated, it depends on a suitable definition of capital costs. Since the process has not yet been operated commercially, there will always be uncertainty in the cost estimate.

DYNAPHEN II CASE

In order to provide the maximum economy of scale for the Dynaphen process, along with the greatest cash flow, a second Dynaphen case was constructed in which the phenolics from the tar oil stream were processed in addition to the naphtha and crude phenol streams. The product slate, capital cost and operating cost are given in Table 93.

Figure 76 presents the economic results. A discounted cash flow rate of return of 33.8 percent is achieved at a liquids transfer price of $1.00 per million BTU. This falls to 21.0 percent at a liquids transfer value of $3.00 per million BTU. This processing scheme, like the previous Dynaphen case, is rather sensitive to capital costs, with the maximum return dropping from 33.8 percent to 21.5 percent if the capital cost is doubled.

It should be noted that no allowance was made for the cost of a tar oil distillation column to cut out the phenolic stream. This omission was justified on the grounds that this case would probably be implemented only if jet fuel were made from the tar oil and that the still would be provided as part of the jet fuel manufacturing facilities.

TABLE 92

ECONOMIC PARAMETERS FOR DYNAPHEN CASE
(Processing Naphtha Plus Phenol Streams)

Product Slate

Product	Million Pounds/Year	Dollars Per Pound	Dollars Per Year
Benzene	35.0	0.157	$5,495,000
Phenol	50.9	0.213	13,387,000
			$18,882,000

Capital Cost

Depreciable Capital Cost	$11,000,000
Working Capital	3,147,000
Pre-Production Startup Expense	513,000
	$14,660,000

Operating Cost

Fixed Operating Cost	$1,888,000
Hydrogen	1,340,000
Liquids Transfer Net Cost @ $1/MMBTU	2,414,000
Total Operating Cost @ $1/MMBTU	$5,640,000
Total Operating Cost @ $2/MMBTU	$8,056,000
Total Operating Cost @ $3/MMBTU	$10,470,000

TABLE 93

ECONOMIC PARAMETERS FOR DYNAPHEN II CASE
(Processing Naphtha + Phenol + Light Oil Streams)

Product Slate

Product	Million Pounds/Year	Dollars Per Pound	Dollars Per Year
Benzene	35.0	0.157	$5,495,000
Phenol	72.9	0.213	19,000,000
			$24,495,000

Capital Cost	
Depreciable Capital Cost	$15,000,000
Working Capital	4,082,000
Pre-Production Startup Expense	652,000
	$19,734,000
Operating Cost	
Fixed Operating Cost	$2,541,000
Hydrogen	2,010,000
Liquids Transfer Net Cost @ $1/MMBTU	2,993,000
Total Operating Cost @ $1/MMBTU	$7,544,000
Total Operating Cost @ $2/MMBTU	$10,537,000
Total Operating Cost @ $3/MMBTU	$13,530,000

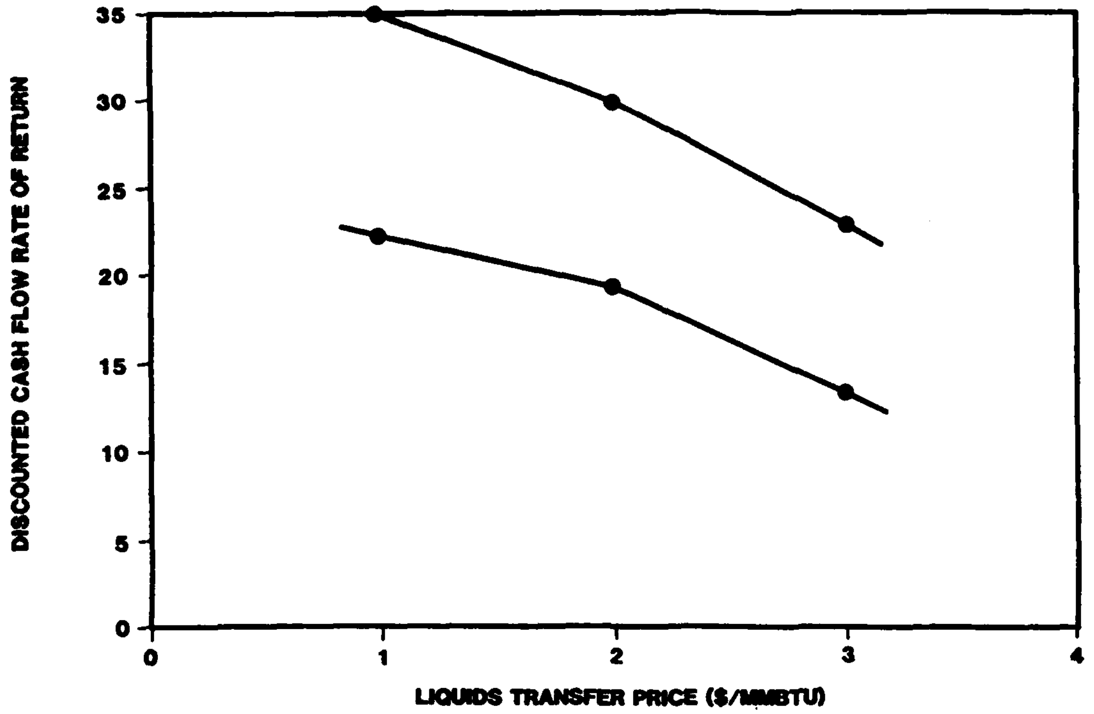


FIGURE 75

DYNAPHEN BENZENE PLUS PHENOL
NAPHTHA & PHENOLS

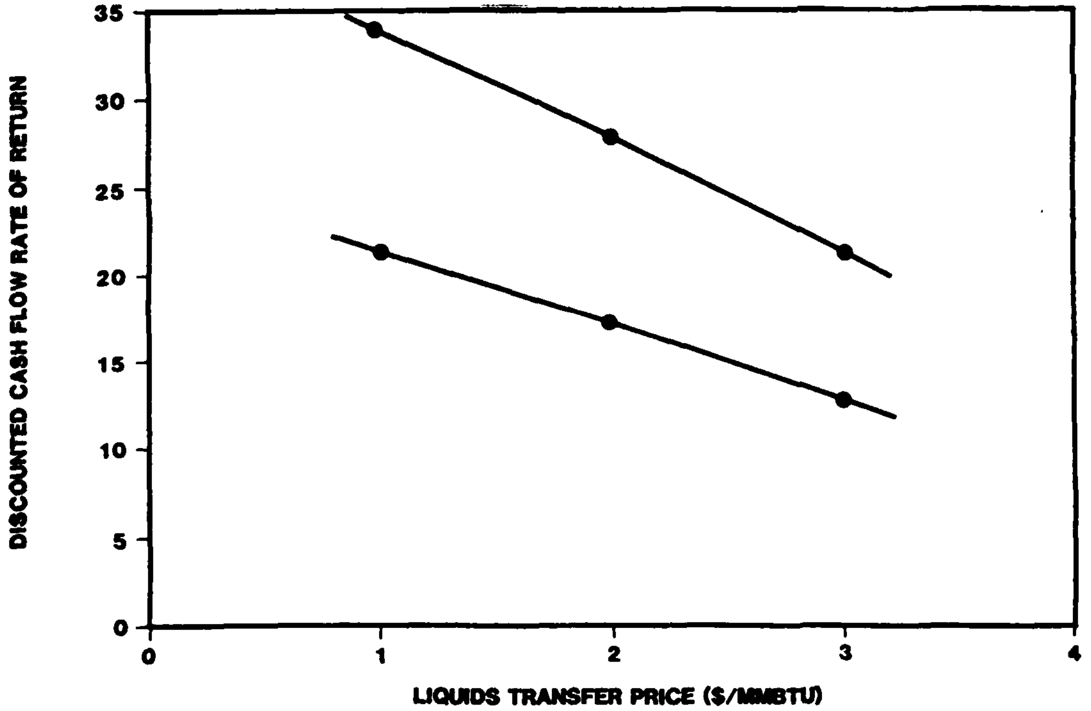


FIGURE 76

DYNAPHEN BENZENE PLUS PHENOL
(NAPHTHA, PHENOLS, TAR OIL)

SUMMARY OF ECONOMIC RESULTS

Summary pages from the computer printout for each run may be found in the Appendix. The major financial parameters of interest are the discounted cash flow rate of return on investment, the net present value, and the total net cash flow over the project life. These parameters are listed for the base case (best estimate for capital cost) runs in Table 94. The calculation of net present value depends upon the assumed value for threshold rate of return. Because both eight percent and ten percent are often used for threshold rate of return, the net present value was calculated both ways.

SENSITIVITY TO TRANSPORTATION COSTS

Four different cases showing attractive rates of return are based on the flow schemes which were referred to as the Benzene case (**Benzene**), the BTX case (**BTX**), the Dynaphen II case (**Benzene + Phenol**) and the Grady/ANG case (**Multiproduct**).

The **Benzene** and **BTX** cases treat only the naphtha stream and produce essentially a single product; the **Benzene + Phenol** treat the naphtha and phenol streams and part of the tar oil stream to produce two products; and the **Multiproduct** case treats all by-product streams to produce a wide range of products. It was of interest to see how these four different cases might vary in their sensitivity to the cost of transporting products to market.

Sensitivity cases were run for each of these four process concepts by changing the product transportation costs by plus or minus 100 percent. The starting point in each case was a liquids transfer cost of $2 per million BTU. The results of the sensitivity analysis are listed in Table 95 and plotted in Figure 77. As noted in Table 95 a doubling of the product transportation cost over the base case estimate leads to a decrease of three to four percentage points in the discounted cash flow rate of return on investment. This confirms initial assumptions that product transportation is a significant factor in marketing by-products from the Great Plains plant.

Figure 77 indicates that all four product slates are affected to about the same degree.

SENSITIVITY TO PRODUCT PRICES

The same four cases as above were also tested for sensitivity to product prices. A sensitivity range of -25 percent to +50 percent was tested, using the same base cases as before. Results are shown in Table 96 and Figure 78. The effects were very similar in all cases, with the rate of return on investment increasing almost in proportion to product prices. The multiple product cases benefit somewhat more than the single product cases.

TABLE 94

SUMMARY OF ECONOMIC RESULTS
(Results in 1987 Dollars)

Case	DCFROR Percent	NPV at 8% DCFROR, $Million	NPV at 10% DCFROR, $Million	Net Cash FLow, $Million
El Paso, (multiproducts scheme)				
$1 Transfer Cost	14.3	50.1	29.8	219.7
$2 Transfer Cost	9.3	9.1	-4.3	123.3
$3 Transfer Cost	2.6	-31.8	-38.4	26.9
El Paso, modified hydrogen source (multiproducts)				
$1 Transfer Cost	20.2	99.9	72.2	329.5
$2 Transfer Cost	15.8	59.0	38.1	233.2
$3 Transfer Cost	10.7	18.1	4.0	136.8
El Paso, non-hydrotreating, BTX to plant fuel				
$1 Transfer Cost	10.8	12.4	3.1	91.9
$2 Transfer Cost	3.3	-17.3	-21.7	22.1
$3 Transfer Cost	-12.7	-47.0	-46.4	-47.8
Grady/ANG, (multiproducts scheme)				
$1 Transfer Cost	28.9	122.8	95.3	351.3
$2 Transfer Cost	24.2	88.9	67.0	271.5
$3 Transfer Cost	18.9	55.0	38.8	191.7
Grady, using El Paso cost for tar acid extraction				
$1 Transfer Cost	15.4	66.6	42.3	269.7
$2 Transfer Cost	11.9	32.7	14.0	189.9
$3 Transfer Cost	7.8	-1.2	-14.2	110.1
Grady, non-hydrotreating case				
$1 Transfer Cost	32.0	99.1	77.7	275.9
$2 Transfer Cost	28.6	81.0	62.7	233.3
$3 Transfer Cost	24.9	62.9	47.6	190.8
Grady, non-hydrotreating, using El Paso tar acid unit				
$1 Transfer Cost	17.4	67.3	45.9	245.0
$2 Transfer Cost	15.2	49.2	30.8	202.5
$3 Transfer Cost	12.8	31.1	15.8	160.0
Cresylic Acids Only, treating phenols plus tar oil stream				
$1 Transfer Cost	12.8	29.2	14.9	148.3
$2 Transfer Cost	9.3	7.3	-3.3	96.8
$3 Transfer Cost	5.0	-14.6	-21.5	45.4

TABLE 94 (Continued)

SUMMARY OF ECONOMIC RESULTS
(Results in 1987 Dollars)

Case	DCFROR Percent	NPV at 8% DCFROR, $Million	NPV at 10% DCFROR, $Million	Net Cash FLow, $Million
Cresylic Acids Only, treating phenols stream only				
$1 Transfer Cost	11.0	10.5	3.1	72.4
$2 Transfer Cost	8.1	0.4	-5.3	48.6
$3 Transfer Cost	4.7	-9.7	-13.7	24.9
Benzene, (Litol treating naphtha stream only)				
$1 Transfer Cost	23.3	13.0	9.8	39.9
$2 Transfer Cost	20.2	9.9	7.2	32.6
$3 Transfer Cost	16.9	6.8	4.6	25.2
BTX, (Unibon + Sulfolane extraction, naphtha only)				
$1 Transfer Cost	26.8	13.9	10.7	40.2
$2 Transfer Cost	23.6	10.9	8.2	33.2
$3 Transfer Cost	20.0	7.9	5.7	26.1
Dynaphen, (benzene + phenol) from (naphtha + phenols) streams				
$1 Transfer Cost	35.9	46.2	36.6	125.1
$2 Transfer Cost	29.6	33.1	25.7	94.3
$3 Transfer Cost	22.5	19.9	14.8	63.4
Dynaphen, treating naphtha, phenols, tar oil streams				
$1 Transfer Cost	33.8	56.2	44.3	154.3
$2 Transfer Cost	27.8	39.9	30.8	116.0
$3 Transfer Cost	21.0	23.7	17.2	77.8

TABLE 95

SENSITIVITY TO PRODUCT TRANSPORTATION COSTS
(Liquids Transfer Value Set at $2/Million BTU)

Case	DCFROR, Percent	Net Present Value at 10% DCFROR $ Million	Total net Cash Flow, $ Million
Benzene			
Low Transport Cost	23.1	9.63	39.5
Base Case	20.2	7.18	32.6
High Transport Cost	17.1	4.72	25.6
BTX			
Low Transport Cost	26.8	10.6	40.1
Base Case	23.6	8.16	33.2
High Transport Cost	20.1	5.72	26.3
Benzene + Phenol			
Low Transport Cost	31.5	37.0	139.3
Base Case	27.8	30.8	116.0
High Transport Cost	23.8	22.5	92.8
Multiproduct			
Low Transport Cost	28.1	90.1	336.8
Base Case	24.2	67.0	271.5
High Transport Cost	19.9	43.9	206.3

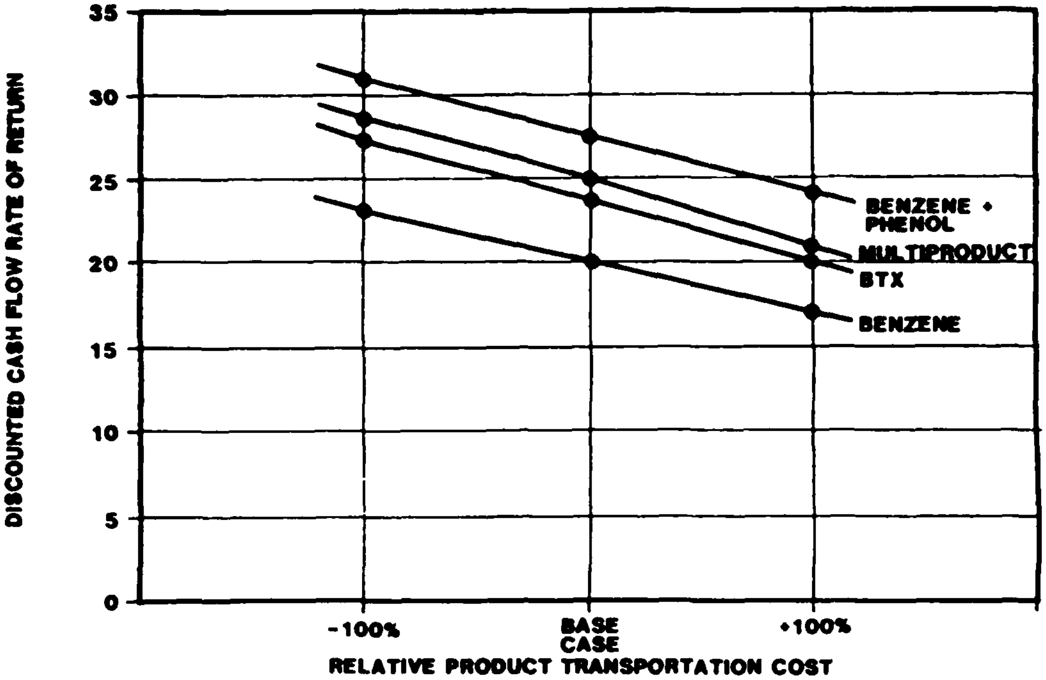


FIGURE 77

SENSITIVITY TO PRODUCT TRANSPORTATION COSTS

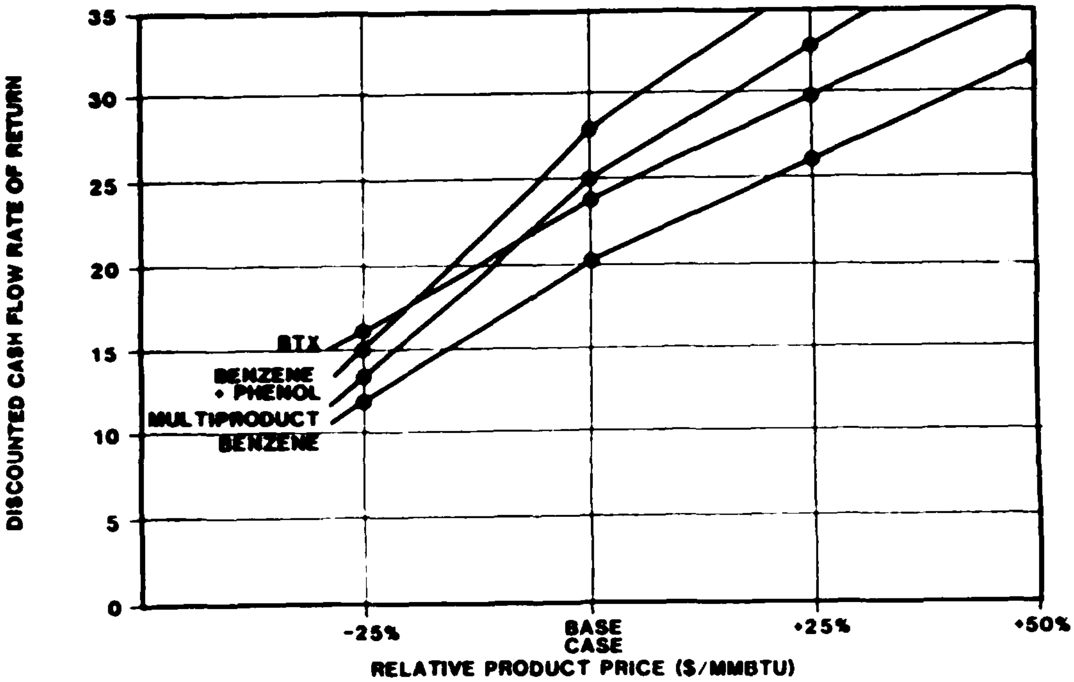


FIGURE 78

SENSITIVITY TO PRODUCT PRICES

TABLE 96

SENSITIVITY TO PRODUCT PRICES
(Liquids Transfer Value Set at $2/Million BTU)

Case	DCFROR, Percent	Net Present Value at 10% DCFROR, $ Million	Total Net Cash Flow, $ Million
Benzene			
High Product Prices	32.1	18.6	64.9
Base Case	20.2	7.2	32.6
Low Product Prices	12.6	1.5	16.6
BTX			
High Product Prices	36.2	18.9	63.5
Base Case	23.6	8.2	33.2
Low Product Prices	15.5	2.9	18.2
Benzene + Phenol			
High Product Prices	46.1	78.1	249.7
Base Case	27.8	30.8	116.0
Low Product Prices	15.2	7.3	49.9
Multiproduct			
High Product Prices	41.1	182.4	597.6
Base Case	24.2	67.0	271.5
Low Product Prices	12.5	9.7	109.5

RISK ANALYSIS

The effects of uncertainties in cost estimates and in price forecasts can be evaluated by the technique of risk analysis. A Monte Carlo type economic risk analysis was carried out for the same four process configurations as were used in the economic sensitivity runs. Triangular probability distribution curves were defined for capital costs and for product prices. In these distribution curves, the most likely value, defining the peak of the distribution, is the value which was used in making the base case runs. The upper and lower limits on the distribution were specified as -20 percent to +100 percent for the capital cost and -25 percent to +75 percent for the product prices.

Five hundred simulations were conducted for each evaluation at a liquids transfer value of $2 per million BTU. This resulted in probability distribution curves for both the DCFROR and the NPV. The results are summarized in Table 97 and in Figure 79 (DCFROR) and Figure 80 (NPV).

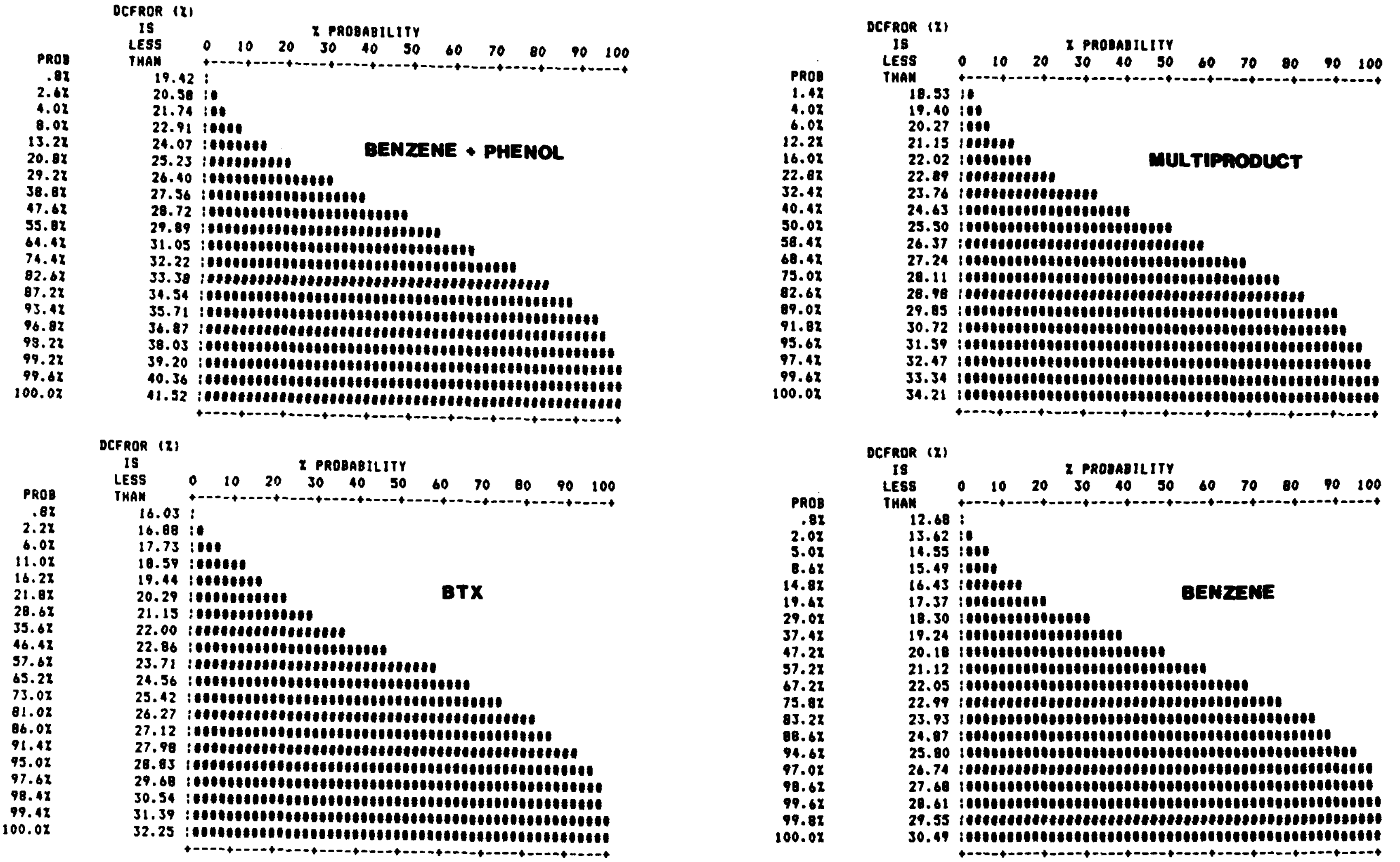
The expected values for DCFROR and NPV were changed very little by the risk analyses, although the Dynaphen (Benzene + Phenol) case showed a gain of a little over one percentage point in DCFROR.

This makes it even more clearly the case with the best rate of return. Table 97 suggests that it is also the case with the most risk (uncertainty) associated with the estimated rate of return. The standard deviation about the mean DCFROR is 4.4 percentage points for the Dynaphen case, compared to a standard deviation no larger than 3.6 percentage points for the other cases. However, this is partly due simply to having a larger expected DCFROR. On a relative basis, the Benzene case, with a DCFROR of 20.2 +/- 3.35, exhibits a wider range of uncertainty.

TABLE 97

RESULTS OF ECONOMIC RISK ANALYSIS
(Liquids Transfer Value set at $2/Million BTU)

	DCFROR, Percent		NPV, $ Million	
Case	Expected	Std. Dev.	Expected	Std. Dev.
Benzene	20.2	3.35	13.8	2.9
BTX	23.2	3.43	14.8	2.2
Benzene + Phenol	29.1	4.44	60.9	9.1
Multiproduct	25.4	3.63	136.7	15.0



BENZENE + PHENOL

PROB	DCFROR (%) IS LESS THAN
.8%	19.42
2.6%	20.58
4.0%	21.74
8.0%	22.91
13.2%	24.07
20.8%	25.23
29.2%	26.40
38.8%	27.56
47.6%	28.72
55.8%	29.89
64.4%	31.05
74.4%	32.22
82.6%	33.38
87.2%	34.54
93.4%	35.71
96.8%	36.87
98.2%	38.03
99.2%	39.20
99.6%	40.36
100.0%	41.52

MULTIPRODUCT

PROB	DCFROR (%) IS LESS THAN
1.4%	18.53
4.0%	19.40
6.0%	20.27
12.2%	21.15
16.0%	22.02
22.8%	22.89
32.4%	23.76
40.4%	24.63
50.0%	25.50
58.4%	26.37
68.4%	27.24
75.0%	28.11
82.6%	28.98
89.0%	29.85
91.8%	30.72
95.6%	31.59
97.4%	32.47
99.6%	33.34
100.0%	34.21

BTX

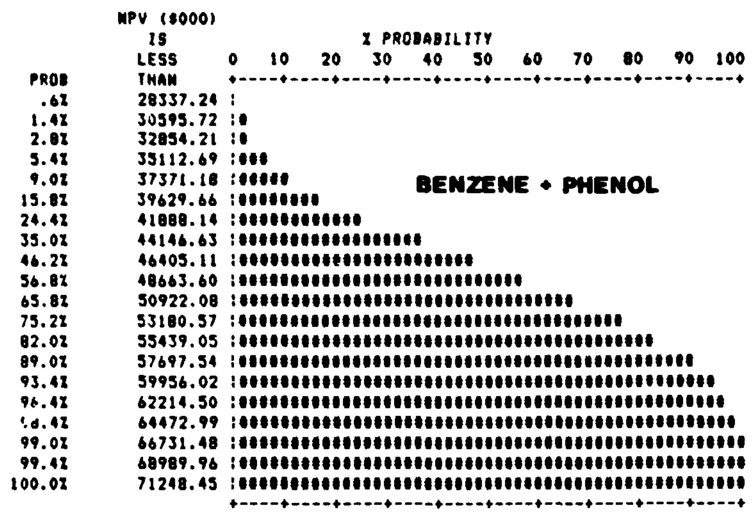
PROB	DCFROR (%) IS LESS THAN
.8%	16.03
2.2%	16.88
6.0%	17.73
11.0%	18.59
16.2%	19.44
21.8%	20.29
28.6%	21.15
35.6%	22.00
46.4%	22.86
57.6%	23.71
65.2%	24.56
73.0%	25.42
81.0%	26.27
86.0%	27.12
91.4%	27.98
95.0%	28.83
97.6%	29.68
98.4%	30.54
99.4%	31.39
100.0%	32.25

BENZENE

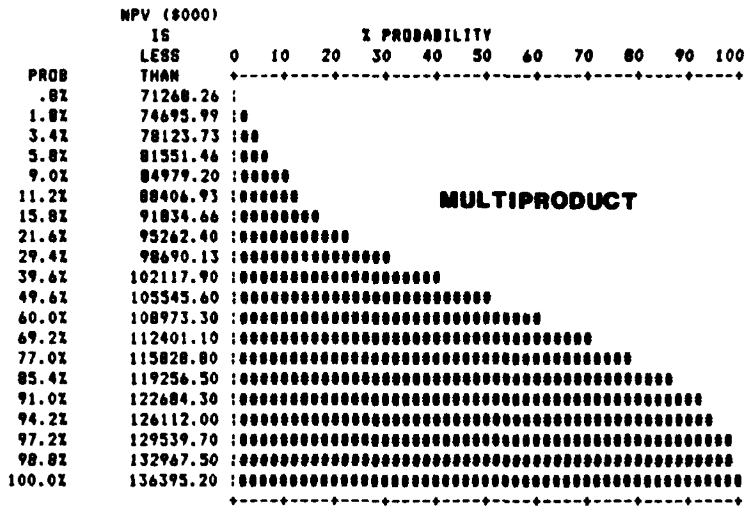
PROB	DCFROR (%) IS LESS THAN
.8%	12.68
2.0%	13.62
5.0%	14.55
8.6%	15.49
14.8%	16.43
19.6%	17.37
29.0%	18.30
37.4%	19.24
47.2%	20.18
57.2%	21.12
67.2%	22.05
75.8%	22.99
83.2%	23.93
88.6%	24.87
94.6%	25.80
97.0%	26.74
98.6%	27.68
99.6%	28.61
99.8%	29.55
100.0%	30.49

FIGURE 79

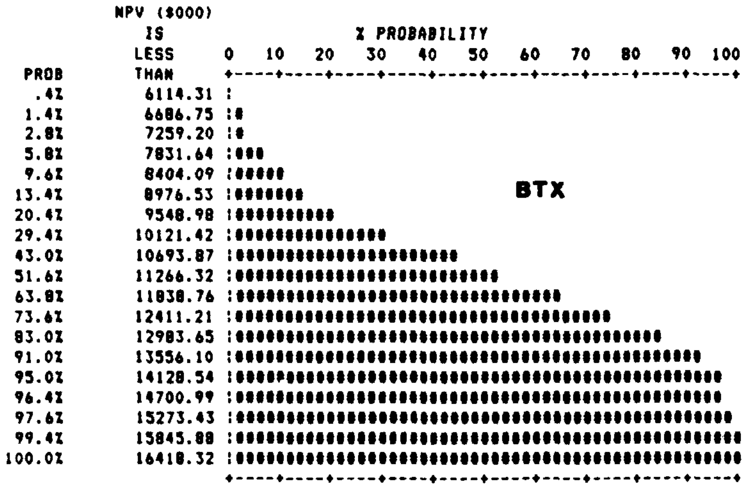
RISK ANALYSIS RESULTS ON DCFROR



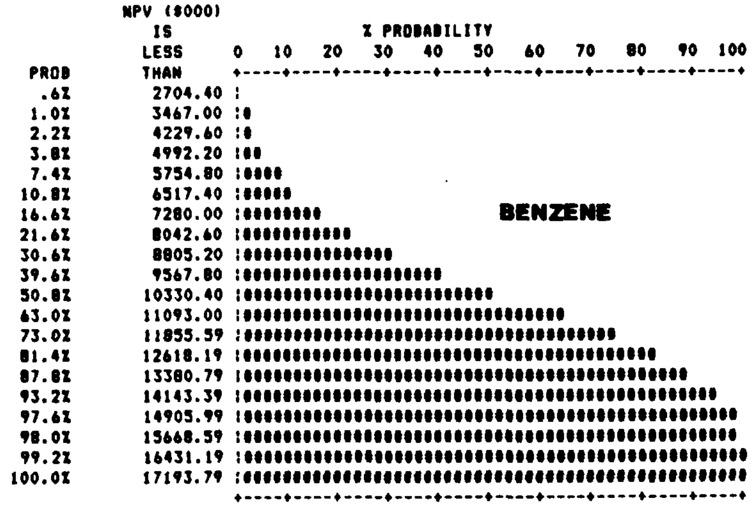
PROB	NPV ($000) IS LESS THAN
.6%	28337.24
1.4%	30595.72
2.8%	32854.21
5.4%	35112.69
9.0%	37371.18
15.8%	39629.66
24.4%	41888.14
35.0%	44146.63
46.2%	46405.11
56.8%	48663.60
65.8%	50922.08
75.2%	53180.57
82.0%	55439.05
89.0%	57697.54
93.4%	59956.02
96.4%	62214.50
98.4%	64472.99
99.0%	66731.48
99.4%	68989.96
100.0%	71248.45



PROB	NPV ($000) IS LESS THAN
.8%	71268.26
1.8%	74695.99
3.4%	78123.73
5.8%	81551.46
9.0%	84979.20
11.2%	88406.93
15.8%	91834.66
21.6%	95262.40
29.4%	98690.13
39.6%	102117.90
49.6%	105545.60
60.0%	108973.30
69.2%	112401.10
77.0%	115828.80
85.4%	119256.50
91.0%	122684.30
94.2%	126112.00
97.2%	129539.70
98.8%	132967.50
100.0%	136395.20



PROB	NPV ($000) IS LESS THAN
.4%	6114.31
1.4%	6686.75
2.8%	7259.20
5.8%	7831.64
9.6%	8404.09
13.4%	8976.53
20.4%	9548.98
29.4%	10121.42
43.0%	10693.87
51.6%	11266.32
63.8%	11838.76
73.6%	12411.21
83.0%	12983.65
91.0%	13556.10
95.0%	14128.54
96.4%	14700.99
97.6%	15273.43
99.4%	15845.88
100.0%	16418.32



PROB	NPV ($000) IS LESS THAN
.6%	2704.40
1.0%	3467.00
2.2%	4229.60
3.8%	4992.20
7.4%	5754.80
10.8%	6517.40
16.6%	7280.00
21.6%	8042.60
30.6%	8805.20
39.6%	9567.80
50.8%	10330.40
63.0%	11093.00
73.0%	11855.59
81.4%	12618.19
87.8%	13380.79
93.2%	14143.39
97.6%	14905.99
98.0%	15668.59
99.2%	16431.19
100.0%	17193.79

FIGURE 80

RISK ANALYSIS RESULTS ON NET PRESENT VALUE

OUTLOOK TO 1995

The market outlook for individual products which might be produced from the Great Plains liquid by-product streams was discussed in the "Market Assessment" section for each product. Each product forms a part of, and is keyed to, the state of the overall economy. The overall economy swings through both short-term and long-term business cycles, which define generally favorable and unfavorable periods for capital investment. In undertaking to produce a basic commodity, it is important to analyze how that commodity will be affected by general trends in the economy. It is always desirable to try to separate short-term effects from the longer-term outlook, over which any capital investment would have to be repaid.

WORLD TRENDS

The period 1984 to 1986 saw a sharp world-wide decline in the prices of most non-fuel basic commodities. From the second quarter of 1984 to the third quarter of 1986, commodity prices, as measured by the International Monetary Fund index of prices for 34 non-fuel commodities, fell by nearly one fourth in terms of United States dollars and by more than one third in terms of Special Drawing Rights. In the third quarter of 1986 these indices were at their lowest levels since the first half of 1976, when prices were low in the wake of the 1975 recession. It is difficult to make precise comparisons for longer term movements of commodity prices in real terms, i.e. prices adjusted for inflation, because of the difficulties in obtaining consistent historical data. However, it seems clear that real commodity prices in the third quarter of 1986 had fallen to a level not experienced since at least the 1930s. Some examples include copper, down 37 percent since 1980, aluminum, down 35 percent since 1980, iron ore down 20 percent, tin down 46 percent, zinc down 24 percent.

Because these price drops pre-date the fall in oil prices, they are obviously not a consequence of the latter. They are a consequence of the fact that major industries, world-wide, have over-invested in production capacity. This, combined with a downturn in demand, has created the pricing problem. Theoretically, the forces of supply and demand will produce prices which eventually cause the shutdown of "excess" capacity until the remaining producers can operate at a profit. This has been slow to occur, however, because of governmental and institutional incentives in many countries to keep producing regardless of price levels.

As an example, it has been estimated that the world overcapacity in steel is 75 to 200 million metric tons per year, out of a total capacity of 570 million tons in non-communist countries. Chase Econometrics states that only if the entire United States steel industry shut down would demand equal supply in the non-communist world. For Great Plains, this creates a positive aspect, in that supplies of by-product coal tar from the steel industry should continue to diminish, through 1995 and beyond.

ORGANIC CHEMICALS

The chemical sector is likely to be the first major commodity industry to break the trend of declining prices and profitability, and excessive overcapacity. Chemical companies have shut down scores of plants in recent years, and are finally seeing some growth in plant capacity utilization. According to the Chemical Manufacturers Association, chemical plant capacity factors rose to 80.5 percent from 66 percent five years ago. The association expects plant use to reach 82.3 percent in 1987.

The wave of plant closures in the early 1980's represented a dramatic turnaround from the industry's building boom in the mid-1970's. After six years of restructuring, cutbacks now appear to have succeeded in bringing capacity back in line with demand. Total production in 1986 at 540 billion pounds was essentially unchanged from 1985, and was still below the peak of 575 billion pounds reached in 1979, but was decidedly improved over the decade low point of 464 billion pounds registered in 1982. Although overall demand was flat between 1985 and 1986, the total was composed of a 9.2 percent increase in demand for organic chemicals, coupled with a further 5.1 percent decline in inorganic chemicals. Thus, the organic chemicals sector, which would encompass all the Great Plains by-products, appears to be fully recovered.

Some organic chemicals are already in short supply. Polystyrene plants are calculated to be running at 94 percent of capacity. Recent sharp price increases for benzene and phenol were discussed earlier. Several plans for new, small, specialty chemicals plants are under consideration. Business cycle analysis suggests that now would be an ideal time to invest in new organic chemical plant capacity. Such an investment should only be made in a project which is economically feasible now; but the investment can be made with a high degree of confidence that conditions in general will improve rather than deteriorate by 1995.

PETROLEUM

Producers of organic chemicals derived from petroleum may worry less about oil prices than about excess manufacturing capacity. Their business is based on competition over the manufacturing markup on petroleum prices, regardless of the price of petroleum itself. Producers of coal-based chemicals, such as Great Plains, however, must be vitally concerned about the absolute level of petroleum prices. Because world oil prices are subject to manipulation by the Organization of Petroleum Exporting Countries, it is difficult to make price forecasts based strictly on a supply/demand analysis.

The dramatic break in oil prices in 1986 created serious problems for the petroleum industry. It was, of course, almost totally disastrous for economically marginal sources of oil such as synthetic fuel processes based on coal. For the long-term picture, little has changed. Petroleum is a finite resource which will eventually be consumed.

Although the economics profession has been unable to successfully predict world oil prices, there are some fundamental facts about world energy markets which have been made more clear by recent events.

Prices are ultimately set by supply/demand relationships, and it is now obvious that energy demand is limited at any given price. In the 1970's, projections of future petroleum demand were based on continued exponential growth in total energy demand. Thoughtful persons realized that continuous exponential growth is impossible, but no one could predict why or when growth in demand would cease. For the time being, the world's potential supply of petroleum at the 1985 price of $28 per barrel clearly exceeds the demand at that price. It is not yet clear what the equilibrium supply would be at typical 1986 prices of $14 per barrel. Supply has increased in many areas during the last few years. In 1973 there were only 16 non-OPEC countries in the non-communist world capable of producing at least 25 percent of the oil which they used. Today that number is over 30. Six more non-OPEC countries have become net oil exporters in the same period.

Faced with an inexorable decline in the demand for their oil, several oil exporting countries abandoned, in late 1985, the strategy of curtailing production to keep prices high and, instead began to increase production for sale at market-determined prices. The resulting significant excess of supply over demand drove prices down sharply in 1986. The immediate effect of this price drop, in terms of decreased exploration activity, canceling new production plans and shutting in marginal producing wells, indicates clearly that 1986 oil prices would be insufficient to maintain supplies at current levels. We can therefore safely conclude that the economically optimum world price for oil in the near-to mid-term future is somewhere between $14 and $28 per barrel. There is a mild consensus by industry analysts that for the near-term it is probably in the neighborhood of $18 to $20 per barrel, although wide differences of opinion, both higher and lower, exist. By 1995, prices should again be approaching the top of the optimum range, or $28 per barrel.

With respect to the Great Plains situation, the difference between the price of oil and the price of coal is of fundamental concern. It is this difference which will justify or not justify burning coal instead of tar oil in the plant and using the tar oil to make petroleum-related products.

The relative share of the energy market captured by coal and oil undergoes slow but massive changes over time as a function of relative prices. Comparing oil and coal prices over a period of only a few years can be extremely misleading because of the lagging effects of long-term purchase contracts, the effects of inflation on capital costs for new mines, etc.

Any such general comparison also suffers from the non-fungible nature of coal, intermixing of data for thermal coal and metallurgical coal, contract versus spot market prices, world versus domestic markets, regional differences, etc. Nevertheless, a long-term comparison can be instructive. Figure 81 shows inflation-corrected prices for oil and coal over approximately the last 120 years. Although the possible shortcomings of such data must be remembered, there is a rough overall correlation between oil and coal prices.

Because there is no application where coal and oil compete in which coal would be preferable to oil at the same price per BTU, coal will take market share from oil only if it is available at a substantially lower price. Another way of looking at the situation is that converting either the form of coal (so that it can be used in oil-fueled equipment) or the form of equipment (so that it can use coal instead of oil) requires a differential between coal and oil prices. If oil is lower priced, no substitution will occur. Even when oil is higher priced, the coal/oil differential (COD) must be large enough to make some conversions feasible.

The constant-dollar COD is plotted in Figure 82. When the COD is positive, it indicates the amount of cash flow per BTU of fuel consumed which can be

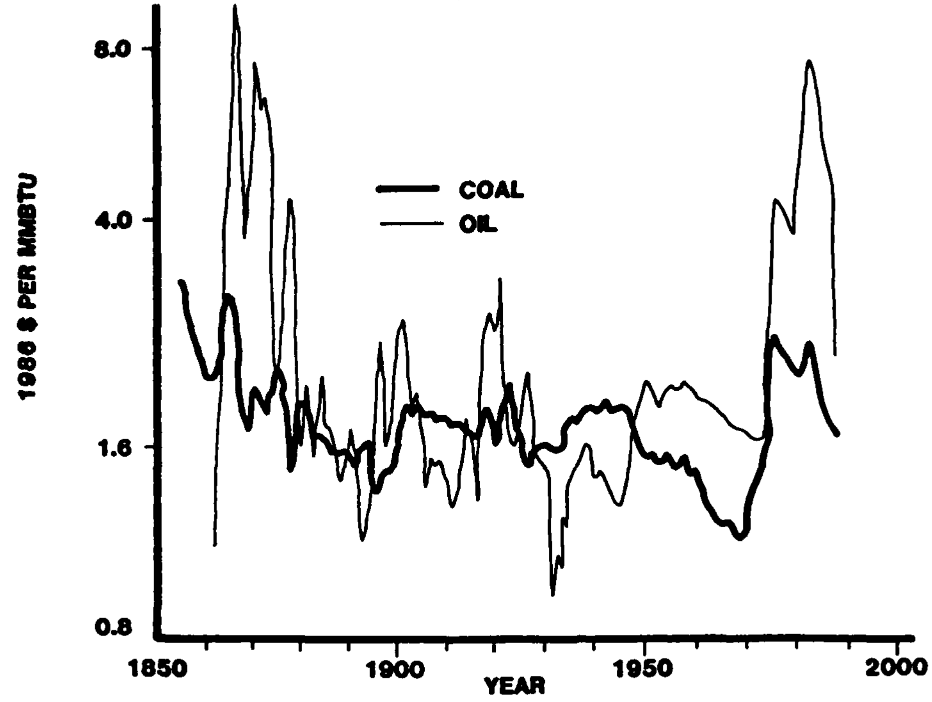


FIGURE 81

INFLATION - CORRECTED COAL & OIL PRICES

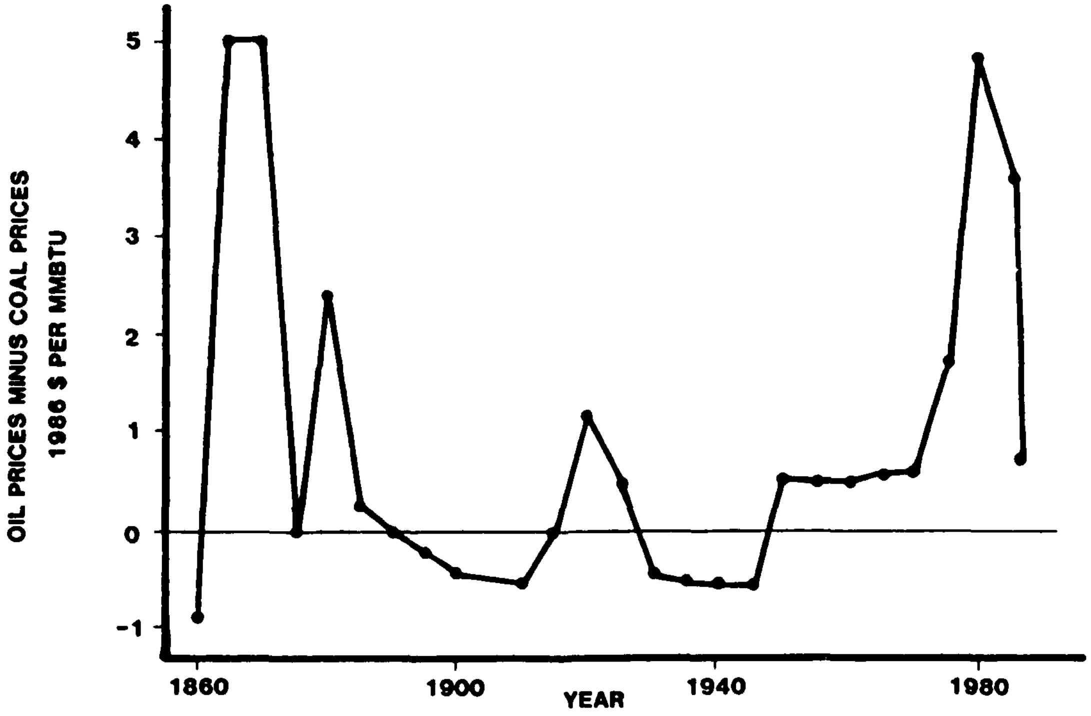


FIGURE 82

THE COAL - OIL DIFFERENTIAL

devoted either to manufacturing coal fuels with improved qualities or to direct coal utilization. It is easy to see why the period from the 1930's to 1950 saw a massive substitution of oil for coal in applications such as railroad locomotives.

Only after 1970 did the COD show a great increase, sparking widespread interest and activity in synthetic fuels from coal. Viewed from this perspective, the 1986 drop in oil prices appears to have returned the COD to its historical range. It appears prudent to conduct planning on the basis of a long-term COD of much less than the $5 per million BTU evidenced in 1980. The COD applicable to a particular coal would have to be adjusted for the difference between the production cost for that coal and the average production cost represented in Figure 82.

The coal/oil differential may be viewed as roughly equivalent to the price that a by-products operation could afford to pay as a transfer cost for the raw liquid streams. If the transfer cost (exclusive of the value of the lignite) is more than the coal/oil differential, then it will not be feasible to produce liquid products which compete directly with petroleum products. Figure 82 suggests that a coal/oil differential of less than $1 per million BTU will prevail in the period to 1995. Unless a liquids transfer cost of approximately this order of magnitude can be achieved, the production of petroleum-type products such as gasoline, diesel fuel, processing oils, etc. is unlikely to be profitable. Only those products whose characteristics or manufacturing costs derive some benefit from the specific chemical composition of the Great Plains liquids should be pursued.

OUTLOOK FOR SIC INDUSTRIES USING GREAT PLAINS PRODUCTS

Several of the major products likely to be produced by the Great Plains Gasification Project can be related to the four-digit industry codes published in the Standard Industrial Classification Manual, prepared by the Statistical Policy Division and published by the Office of Management and Budget. (The new Standard Industrial Classification Manual (SIC) will be published in mid-1987.)

Using the SIC manual and the latest published national input-output tables, it is possible to determine which industries are significant purchasers of the products which could be produced at Great Plains. This section describes the national input/output relationships between industries and the outlook for industries which are purchasers of potential Great Plains products. Relationships were found for the following:

Product	Industry
Carbon black	Rubber tires - SIC 3011
Rubber processing oils	Synthetic rubber - SIC 2822
Phenols	Plastics and resins - SIC 2821
Cresylic acids	Paints and varnishes - SIC 2851
Cresols	Adhesives and sealants - SIC 2891

Binder pitch	Aluminum smelting - SIC 3334
Creosote	Wood preservative - SIC 2491 (railroad ties, utility poles, etc.)
Coal tar pitch	Roofing compounds - SIC 2952

Outlook For Rubber Tires And Inner Tubes - SIC 3011

Rubber products shipments are highly dependent on the motor vehicle market. Approximately 85 percent of shipments go to passenger cars, trucks, and buses. Other markets include aircraft, agricultural, industrial, motorcycle, and bicycle uses. Inner tubes represent less than two percent of shipments now that tubeless tires dominate most markets.

As the rubber tires industry has shifted to longer-lasting radial tires, more than 20 older tire plants have closed. Employment in the rubber tire industry has dropped from 114,000 in 1977 to 66,500 in 1985. There have also been significant gains in imports of foreign automobiles with tires mounted and in imports of replacement tires. Import of replacement tires increased from 20 million annually during 1972-82 to 37 million in 1984. This trend is expected to continue. Tire exports go mainly to Canada; imports are shifting away from Canada and Europe to Asia. Asia accounted for 44 percent of United States tire imports in 1985.

Slow growth is seen for the rubber industry, based on a number of conflicting forces. Tires will be longer lasting. But demand will be enhanced by increases in the driving-age population and in motor vehicle mileage driven. Motor vehicles will remain a primary form of transportation and the number in operation will grow.

Outlook For Synthetic Rubber - SIC 2822

Production of synthetic rubber is also suppressed by reduced demand from the automotive industry. The only major exception is production of specialty elastomers. The overall output of the synthetic rubber industry has been adversely affected by the same factors affecting the rubber tire industry.

However, demand for specialty rubbers has grown as markets have developed for new automotive applications. Performance requirements in automotive and other applications have forced the substitution of specialty rubbers for general-purpose rubbers and rubbers have been increasingly alloyed with plastics to form new materials.

During 1985, shipments of synthetic rubber declined six percent from 1984; there also was a three percent decline in exports and a 17 percent increase in imports. The United States has lost world market share over the last few years but exports still amounted to $655 million in 1985.

Synthetic rubber prospects depend on the demand for rubber products in general and on the industry's ability to develop new rubber-based alloyed materials. Growth areas include roofing and oil additives, plus new products created from alloys of rubber and plastics.

Outlook For Plastics And Resins - SIC 2821

Plastics represent a wide variety of materials, with many built-in properties making them adaptable for diverse markets. Packaging and building/construction account for over 50 percent of the plastic end-use market. In addition, plastics are used in furniture, automobiles, toys, electronics, and many other applications. Special properties and high-output processing methods, such as injection molding, combine to give plastics a competitive edge over wood, metals, paper and glass.

The plastics materials industry is capital intensive, and its highly automated production facilities need relatively few production workers. Shipments of plastics in 1985 increased approximately 4 percent in real terms over 1984. U.S. exports of plastics accounted for about 11 percent of U.S. output in 1985. Saudi Arabia has recently entered the world market, a negative factor, but the formerly strong dollar is declining and weak overseas economies seem to be strengthening.

United States imports of plastics materials have been in an upward trend since 1977. Imports in 1985 were up nearly 16 percent following increases of 42 percent in 1984 and 75 percent in 1983. Major sources of imported plastics materials are Japan, Canada and West Germany. Producers in oil-rich countries have a favorable cost position in feedstocks and will continue to build up their capacity.

One of the more dynamic sectors of the plastics industry involves reinforced plastics or composites. Major fibers currently being used are glass, cellulose, aramid, and carbon or graphite. Consumption of plastics composites has been increasing rapidly.

Outlook For Paints And Varnishes - SIC 2851

The paints and coatings industry uses more than a thousand different raw materials to produce binders, pigments, solvents and additives. Strengthened economic conditions improved both the quantity and value of shipments in 1985. Most of the sales effort of the United States industry is directed towards the domestic market. Its ability to compete in foreign trade is limited by the high cost of transportation and fragmentation of the industry. Major export markets for the United States industry have been Canada and Mexico. Import competition is small, but growing.

Shipments by the industry should continue to grow about three percent per year. Growth areas include specialty coatings to pretreat polymer composites surfaces for bonding and new improved paints and specialty coatings for use by electronics manufacturers. Advances in corrosion protection should increase sales of special-purpose coatings.

The number of companies in the industry will probably decrease because of the continued investment needed for production and research and development.

Outlook For Adhesives And Sealants - SIC 2891

Adhesives and sealants are formulated products, similar in composition and design to paints and coatings. Adhesives are highly specialized and complex products tailored to meet the needs of many end-use markets. Packaging is the major market for adhesives, in addition to the construction, transportation, furniture, textile, shoe, bookbinding, and electronics industries.

Strong demand boosted industry shipments by five percent (constant dollars) in 1985. Synthetic resins and rubber-based adhesives accounted for 62 percent of these shipments; sealants and caulking compounds, 20 percent; natural-based adhesives, six percent; and other adhesives and sealants, 12 percent.

International trade in adhesives, both exports and imports, is small and primarily with other industrialized countries. Imports rose 23 percent in 1985; exports slipped because of the high value of the dollar. Canada is the major importer of United States adhesives and sealants, taking 30 percent of United States exports in 1985.

Long term prospects for the industry are favorable. High performance adhesives and sealants are gaining acceptance in a wide variety of applications, and the development and use of new materials are creating demands for improved and new adhesives. Growth will be based on the ability of adhesives to reduce the weight, increase the strength, and improve the quality of products, while also reducing manufacturing costs. Research and development will continue to be a controlling factor.

Outlook For Aluminum Smelting - SIC 3334

The total volume of aluminum industry shipments reached a record level in 1985, but primary aluminum smelters continued to close or to reduce output because prices for primary metal were well below United States producers' average cost of production. The domestic primary aluminum producing sector of the industry is buffeted by high costs (especially for electricity), capacity expansion in low-electricity-cost countries, oversupply, and low prices. These factors have caused the industry to reduce primary output and close capacity that is no longer competitive.

Thus, the domestic aluminum industry is facing a future that should see significant changes in the structure of the industry. In the wake of new offshore capacity are shut-downs of domestic smelters, which could not compete against relatively low electricity costs, low labor costs, and/or increased foreign government involvement.

The rate of growth in demand for primary aluminum has significantly declined due to increased secondary recovery, saturation of certain end use markets, and product improvements. These developments mean that the reopening of smelters that are currently closed is unlikely.

Outlook For The Wood Preservatives Industry - SIC 2491

The value of shipments of treated wood increased by an estimated two percent in 1985 over 1984. The similar increase in 1984 was 5.1 percent. Housing starts are a principal factor affecting demand. Markets for treated lumber and plywood have been expanding, while markets for treated telephone poles, marine pilings, and railroad ties tend to be cyclical and grow slowly over the longer term.

The railroad tie industry is complying with EPA directives that preservatives, such as creosote, should be used only by certified treatment plants or applicators. The EPA has also expressed concern over possible leakage of creosote during railroad tie treatment and in storage yards. In addition, there is concern over proper and safe disposal of used creosote-treated railroad ties by railroads.

Exports of treated wood products fell about 20 percent in 1985, due mostly to the strength of the United States dollar. Most of these exports were treated telephone poles that went to Bangladesh, Canada, the Caribbean, and Saudi Arabia. Exports of these products probably will not increase much unless foreign countries begin new rail, telephone, or port development projects.

Outlook For The Roofing Compounds Industry - SIC 2952

The demand for coal tar pitch used in roofing compounds depends primarily on the construction industry, principally the residential construction industry. The inflation-adjusted value of new construction put in place rose by six percent in 1985 and exceeded the previous peak year of 1973.

Overall construction spending will continue to reach record levels. Public works construction has ended its long-term decline and will grow steadily over the longer term.

DEFINITION OF OPTIMUM PRODUCT SLATE

Many factors enter into the definition of an optimum product slate. The "optimum" slate could be chosen strictly on the basis of the highest indicated rate of return on investment. It could be chosen on the basis of the highest net cash flow above a threshold rate of return. Other factors influencing the choice could be the amount of process (technical) risk, the long-term prospects for market demand, the prospects for future increase in product prices, etc.

DISCOUNTED RATE OF RETURN ON INVESTMENT

Considering only the discounted cash flow rate of return, the case involving HRI's Dynaphen process to make benzene and phenol from the naphtha and crude phenols streams would be assigned the highest ranking. A DCFROR of 22.5 to 35.9 percent was calculated. The only other process configurations achieving a maximum rate of return above 25 percent are the BTX case, based on UOP's Unibon hydrotreating plus Sulfolane extraction technology for the naphtha stream alone, and two multiproduct cases based on cost estimates prepared by R.B. Grady & Associates.

In all of these cases, there is considerable doubt about the accuracy of the capital cost estimate. The Dynaphen process is not yet commercialized, the Unibon and Sulfolane units are usually built in much larger sizes and have not been operated on similar feedstocks, and the Grady estimates were not based on detailed engineering. If the capital cost estimate is doubled, only the Dynaphen schemes show a rate of return above 20 percent.

NET PRESENT VALUE

The DCFROR criterion determines the greatest rate of return per dollar invested. However, a highly profitable but very small project will not contribute much to the total cash flow of a large corporation. It is also important to consider the net present value of all the cash flows generated over the lifetime of the project. When the cash flows are discounted back to the present, using a discount rate of 10 percent, the highest ranking goes to the Grady multiproducts case.

Of course the larger the project, the more money at risk if the project runs into difficulty.

SENSITIVITY TO CAPITAL COST

Because of the large uncertainties regarding capital cost estimates, it is desirable to have a project whose rate of return will still be robust if the capital cost turns out to be much larger than expected. The Dynaphen process shows the highest DCFROR after a doubling of the capital cost estimates.

ABILITY TO MEET PROCESS SPECIFICATIONS

Processes which produce a single fungible chemical as product are likely to have less difficulty in meeting customer specifications than a process which produces complex mixtures of chemicals. The complex mixtures present difficult quality control problems, and it may be necessary to allow the customer to make extensive sample runs before purchasing a product. In this respect, the multiproduct schemes are at a disadvantage because there will be many different specifications that have to be met in order for the plant to be profitable.

MARKET SIZE

The most desirable market to enter is one in which the amount of product which will be produced is small in relation to the total market volume. A product manufactured in large volumes cannot be introduced into a small volume market without depressing prices.

Those products most sensitive to market volume are the cresylic acid cases, where the Great Plains output could be of the same order of magnitude as the United States demand. Creosote could also be affected by market size. Potential benzene and phenol production from Great Plains is very small with respect to the total size of the market.

PROCESS RANKINGS

Each of the process configurations was ranked with respect to the others in accordance with the preceding discussion. The results are seen in Table 98. The two Benzene/Phenol cases (Dynaphen) clearly outranked all the other cases. The Benzene and BTX cases were next, in spite of a very low ranking for net present value. The lowest ranked cases were the Cresylic Acids Only cases.

Although this analysis is helpful in pointing out the more promising avenues to explore, and it points out problem areas which may require attention in some of the cases, it should not be accepted as a definitive judgment on the relative merits of each case. Although the ranking criteria used in Table 98 are commonly encountered, other criteria could be defined which would yield different results. Special situations can greatly change the ranking under any criterion. For example, a sales contract with a cresylic acid processor could remove most of the uncertainty concerning the ability to meet product specifications. This would materially improve the ranking for this process.

There are many unknowns with respect to the high-ranked Dynaphen process. The economic analysis was based on 100 percent conversion of all alkyl phenols to phenol. This could never be achieved in practice and a much lower yield would greatly reduce the estimated rate of return. A 75 percent yield, for example, would reduce the maximum rate of return from 34 percent to about 25 percent, and drop Dynaphen out of the top economic ranking.

OPTIMUM PRODUCT SLATE

Accepting that the words "optimum product slate" are incapable of exact definition, it nevertheless appears that a benzene plus phenol slate would have a number of intrinsic advantages. Of particular interest is the fact that it could be implemented either with or without the simultaneous production of military jet fuel.

There are strong national security arguments for demonstrating the production of military jet fuel at the Great Plains plant. However, the benzene and phenol components of the raw liquid streams are not of value for jet fuel

TABLE 98

PROCESS RANKINGS
(Highest Ranking = 11)

Case	DCFROR	NPV at 10%	Ability to Meet Product Specs	Sensitiv- ity to Capital Cost	Production Relative to Market Volume	Avergage Score
El Paso, Multiproduct	4	6	1	4	6	4.2
El Paso, Modified Hydrogen	5	9	2	5	7	5.6
El Paso, Nonhydrotreating	1	1	4	1	5	2.4
Grady, Multiproduct	8	11	3	8	4	6.8
Grady, Nonhydrotreating	9	10	5	9	3	7.2
Cresylic Acids, Phenols Only	3	5	7	3	2	4.0
Cresylic Aacids, All Streams	2	2	6	2	1	2.6
Benzene, Naphtha Only	6	3	11	6	11	7.4
BTX, Naphtha Only	7	4	10	7	10	7.6
Benzene/Phenol, Naphtha/Phenols	11	7	9	11	9	9.4
Benzene/Phenol, All Streams	10	8	8	10	8	8.8

production. Benzene is too low boiling for jet fuel and the phenolic constituents, if hydrotreated, would be converted to additional light aromatics. These components are not only of the highest value in themselves, but are of the least value for making jet fuel. Therefore an optimum strategy clearly suggests that the light aromatics and phenols in the naphtha and crude phenols streams be treated separately from the tar oil stream. Although it may eventually be possible to recover additional phenols from the tar oil stream, including this source does not appear to increase profitability, and would add additional complexity and technical risk.

The optimum product slate is therefore defined as follows:

Great Plains Plant Stream	Disposition	Final Product
Raw Naphtha	Hydrodealkylation	Benzene
Crude Phenols	Hydrodealkylation	Benzene + Phenol
Tar Oil	Hydrotreating	Military Jet Fuel

Although routes are known for hydrodealkylation of the naphtha stream, the only route discovered for dealkylation without dehydroxylation of the crude phenols stream is the Dynaphen process. Any heavy residue from the tar oil stream could perhaps be developed as a coal tar product for roofing tar or driveway sealers. These applications are purely speculative, however.

If the possibility of making military jet fuel does not materialize, the tar oil stream can best be marketed as creosote, provided that a new specification can be created with the American Wood Preservers Association.

CONCLUSIONS AND RECOMMENDATIONS

FEASIBILITY OF BY-PRODUCT PRODUCTION

The major conclusion of this study is that there are profitable opportunities for by-product development, even if the transfer price assigned to the crude liquid streams from the gasification plant is as high as $3 per million BTU. The profitability of any by-products production scheme is largely affected by the liquids transfer price, and becomes questionable for almost all schemes if the transfer price rises over $3.

Unless petroleum prices increase strongly in the near future (not forecast to occur) none of the potential Great Plains liquid products which would compete directly with crude oil or heavy fuels are likely to be economically practical. This includes such products as refinery feedstock, carbon black feedstock, gasoline, fuel oils and rubber processing oil.

SUITABILITY FOR MILITARY JET FUELS

It was not within the scope of this study to investigate the economics of producing military jet fuels from the gasification plant streams. It was determined that a suitable demand exists within the state of North Dakota to absorb the potential production without having to ship for excessive distances. It is highly unlikely that a jet fuel manufacturing operation could be successful on a commercial basis. A firm purchase contract with the Department of Defense and having a price floor would be required. Since some of the jet fuel supplied to Minot Air Force Base is currently trucked in from Canada, supplying this base from the Great Plains plant would reduce overall petroleum imports.

Long-term national security considerations make the demonstration of a small-scale jet-fuel-from-coal operation highly desirable. This demonstration could utilize the tar oil stream from Great Plains.

EFFECT ON REGIONAL REFINED PRODUCTS BALANCE

The Great Plains market region, consisting of five states and two provinces, is a net exporter of crude oil, and is approximately in balance with respect to production and consumption of refined products. It is concluded that any new production of refined products in the region, including jet fuel, gasoline, fuel oils and residual oil, would probably result in a slight decrease in regional refinery runs. The decrease in refinery purchases of crude would probably result in more crude oil being exported to other states.

A maximum of 5,000 barrels per day of liquid products could be produced at Great Plains, and this would be less than one percent of regional refining capacity. Therefore no discernible effect on average product prices within the region would be expected, although some effect could be seen at the point of introduction.

PRODUCT SLATE

The economic evaluations carried out in this study suggest that if jet fuel is produced, the naphtha and crude phenols streams are the most suitable for by-product development. Because these streams are not desirable feedstocks for jet fuel production, the optimum product slate consists of jet fuel from tar oil plus chemicals from the naphtha and crude phenols streams. Based on the preliminary economic analyses carried out with the limited cost data available, benzene and phenol would appear to be the most promising candidates. However, this appearance can be affected by a number of factors.

TAR ACIDS EXTRACTION

A major uncertainty in the estimation of capital costs for a multiproduct operation is the cost of a process unit for extracting tar acids from the gasification plant streams. Three major process contenders for this operation are:

1. Caustic extraction and springing with carbon dioxide.
2. Solvent extraction by the Lurgi Phenoraffin process.
3. Solvent extraction by a methanol/hexane solvent, as formerly practiced by Pitt-Consol Company and later by Merichem.

No good capital cost estimates for this process block are available. Using the available information, switching from the first process listed above to the second one made a difference of over 14 percentage points in the maximum calculated discounted cash flow rate of return. It is not possible to make sound judgments on process development routes to follow until the data in this area are improved. It is therefore recommended that some preliminary engineering design effort be expended to arrive at credible up-to-date costs for the tar acid extraction step. If jet fuel is not produced, extraction of cresols from the tar acids would produce the largest total revenue stream.

PROCESS DATA FOR BENZENE PRODUCTION

There are several processes available which might be suitable for making benzene from the naphtha stream. Both thermal and catalytic hydrodealkylation processes have been commercialized, or a solvent extraction process could be used. However, there are large question marks concerning the ability of these processes to handle the Great Plains liquids and concerning the costs for such processes if constructed at the relatively small scale dictated by the Great Plains flows. Further definition of the engineering parameters and costs is required.

COMBINED PRODUCTION OF BENZENE AND PHENOL

The combined production of benzene and phenol by the HRI Dynaphen process is theoretically intriguing. It would make it possible to take advantage of the natural characteristics of the gasification by-product liquids (i.e. high phenol content) rather than simply using brute force to transform the constituents into other, saleable materials.

Demonstrating the feasibility of the Dynaphen process on the Great Plains feedstock will require some basic laboratory research and development because the process is not yet commercialized. The potential advantages of the process would appear to justify such an effort, and it is recommended that this be initiated.

PARALLEL MARKETING EFFORTS

It is strongly emphasized that the apparent economic advantage of the "optimum product slate" defined by this study may be illusory. The cost data used for the upgrading processes are simply not of sufficient quality to draw firm conclusions. Further refinement of the cost data could significantly change the rankings of different processes. Therefore, it is not recommended that any potential by-products be eliminated from consideration at this time. Creosote, cresylic acids and rubber processing oils could be developed as profitable products if the liquids transfer price is low enough.

If the liquids transfer price is above \$3.00 per million BTU, however, it will be difficult to develop a profitable operation based on significant upgrading unless the product selling prices are at least \$5 per million BTU, or approximately \$30 per barrel (\$0.10 per pound). Products clearly meeting this criterion include benzene and other light aromatics, phenol and cresylic acids. Almost all other products become marginal under these conditions.

PRICE OUTLOOK

Prices for most chemical and petroleum commodities have suffered significant declines over the past few years. Further significant declines appear unlikely because present levels are low enough to have resulted in the shutting down of most "excess" capacity. Demand for some chemicals (such as benzene) in the petrochemical sector has recently surged, and there are solid prospects for future growth in demand.

On the whole, the downside risk for future prices of most products should be relatively small. Projects which can be shown to be profitable under current conditions should be even more profitable in the future. It is recommended that planning for by-products production be given a high project priority.

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